Rising energy prices could negatively impact our business.

While we have fuel clause recovery mechanisms in most of our states, higher fuel costs could significantly impact our results of operations if costs are not recovered. In addition, higher fuel costs could reduce customer demand and/or increase bad debt expense, which could also have a material impact on our results of operations. Delays in the timing of the collection of fuel cost recoveries as compared with expenditures for fuel purchases could have an impact on our cash flows. Low fuel costs could have a positive impact on sales although, particularly on the southern part of our service territory, low oil prices could negatively impact oil and gas production activities. We are unable to predict future prices or the ultimate impact of such prices on our results of operations or cash flows.

Our operating results may fluctuate on a seasonal and quarterly basis and can be adversely affected by milder weather.

Our electric and natural gas utility businesses are seasonal, and weather patterns can have a material impact on our operating performance. Demand for electricity is often greater in the summer and winter months associated with cooling and heating. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout our service territory, and a significant amount of natural gas revenues are recognized in the first and fourth quarters related to the heating season. Accordingly, our operations have historically generated less revenues and income when weather conditions are milder in the winter and cooler in the summer. Unusually mild winters and summers could have an adverse effect on our financial condition, results of operations, or cash flows.

Item 1B — Unresolved Staff Comments

None.

Item 2 — Properties

Virtually all of the utility plant property of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS is subject to the lien of their first mortgage bond indentures.

Electric Utility Generating Stations:

NSP-Minnesota

Station, Location and Unit	Fuel	Installed	Summer 2014 Net Dependable Capability (MW)	
Steam:				
A.S. King-Bayport, Minn., 1 Unit	Coal	1968	511	
Sherco-Becker, Minn.				
Unit 1	Coal	1976	680	
Unit 2	Coal	1977	682	
Unit 3	Coal	1987	507	(a)
Monticello-Monticello, Minn., 1 Unit	Nuclear	1971	554	
PI-Welch, Minn.				
Unit 1	Nuclear	1973	521	
Unit 2	Nuclear	1974	519	
Black Dog-Burnsville, Minn., 2 Units	Coal/Natural Gas	1955-1960	215	
Various locations, 4 Units	Wood/Refuse-derived fuel	Various	36	(b)
Combustion Turbine:				
Angus Anson-Sioux Falls, S.D., 3 Units	Natural Gas	1994-2005	327	
Black Dog-Burnsville, Minn., 2 Units	Natural Gas	1987-2002	271	
Blue Lake-Shakopee, Minn., 6 Units	Natural Gas	1974-2005	453	
High Bridge-St. Paul, Minn., 3 Units	Natural Gas	2008	534	
Inver Hills-Inver Grove Heights, Minn., 6 Units	Natural Gas	1972	282	
Riverside-Minneapolis, Minn., 3 Units	Natural Gas	2009	470	
Various locations, 17 Units	Natural Gas	Various	101	
Wind:				
Grand Meadow-Mower County, Minn., 67 Units	Wind	2008	101	(c)
Nobles-Nobles County, Minn., 134 Units	Wind	2010	201	(c)
		Total	6,965	

(a) Based on NSP-Minnesota's ownership of 59 percent.

(b) Refuse-derived fuel is made from municipal solid waste.

(c) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

NSP-Wisconsin

Station, Location and Unit	Fuel	Installed	Summer 2014 Net Dependable Capability (MW)	
Steam:				
Bay Front-Ashland, Wis., 3 Units	Coal/Wood/Natural Gas	1948-1956	56	(a)
French Island-La Crosse, Wis., 2 Units	Wood/Refuse-derived fuel	1940-1948	16	
Combustion Turbine:				
Flambeau Station-Park Falls, Wis., 1 Unit	Natural Gas	1969	12	
French Island-La Crosse, Wis., 2 Units	Natural Gas	1974	122	
Wheaton-Eau Claire, Wis., 6 Units	Natural Gas	1973	290	
Hydro:				
Various locations, 63 Units	Hydro	Various	135	
		Total	631	

(a) Refuse-derived fuel is made from municipal solid waste.

PSCo

Station, Location and Unit	Fuel	Installed	Summer 2014 Net Dependable Capability (MW)	
Steam:				
Cherokee-Denver, Colo., 2 Units	Coal	1957-1968	504	
Comanche-Pueblo, Colo.				
Unit 1	Coal	1973	325	
Unit 2	Coal	1975	335	
Unit 3	Coal	2010	500	(a)
Craig-Craig, Colo., 2 Units	Coal	1979-1980	83	(b)
Hayden-Hayden, Colo., 2 Units	Coal	1965-1976	237	(c)
Pawnee-Brush, Colo., 1 Unit	Coal	1981	505	
Valmont-Boulder, Colo., 1 Unit	Coal	1964	184	
Zuni-Denver, Colo., 1 Unit	Coal	1948-1954	59	
Combustion Turbine:				
Blue Spruce-Aurora, Colo., 2 Units	Natural Gas	2003	264	
Fort St. Vrain-Platteville, Colo., 6 Units	Natural Gas	1972-2009	969	
Rocky Mountain-Keenesburg, Colo., 3 Units	Natural Gas	2004	580	
Various locations, 6 Units	Natural Gas	Various	172	
Hydro:				
Cabin Creek-Georgetown, Colo.				
Pumped Storage, 2 Units	Hydro	1967	210	
Various locations, 9 Units	Hydro	Various	26	
Wind:				
Ponnequin-Weld County, Colo., 37 Units	Wind	1999-2001	25	(d)
		Total	4,978	

(a) Based on PSCo's ownership interest of 67 percent of Unit 3.

(b) Based on PSCo's ownership interest of 10 percent.

(c) Based on PSCo's ownership interest of 76 percent of Unit 1 and 37 percent of Unit 2.

(d) This capacity is only available when wind conditions are sufficiently high enough to support the noted generation values above. Therefore, the on-demand net dependable capacity is zero.

SPS

Station, Location and Unit	Fuel	Installed	Summer 2014 Net Dependable Capability (MW)
Steam:			
Harrington-Amarillo, Texas, 3 Units	Coal	1976-1980	1,018
Tolk-Muleshoe, Texas, 2 Units	Coal	1982-1985	1,067
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1957-1965	254
Jones-Lubbock, Texas, 2 Units	Natural Gas	1971-1974	486
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1967	112
Nichols-Amarillo, Texas, 3 Units	Natural Gas	1960-1968	457
Plant X-Earth, Texas, 4 Units	Natural Gas	1952-1964	411
Combustion Turbine:			
Carlsbad-Carlsbad, N.M., 1 Unit	Natural Gas	1968	10
Cunningham-Hobbs, N.M., 2 Units	Natural Gas	1998	212
Jones-Lubbock, Texas, 2 Units	Natural Gas	2011-2013	338
Maddox-Hobbs, N.M., 1 Unit	Natural Gas	1963-1976	61
		Total	4,426

Electric utility overhead and underground transmission and distribution lines (measured in conductor miles) at Dec. 31, 2014:

Conductor Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
500 KV	2,917	—	—	—
345 KV	8,403	1,152	2,630	8,110
230 KV	1,803	—	12,162	9,312
161 KV	416	1,575	—	—
138 KV	—	—	92	—
115 KV	7,502	1,746	4,889	12,378
Less than 115 KV	84,090	32,408	75,110	23,294

Electric utility transmission and distribution substations at Dec. 31, 2014:

	NSP-Minnesota	NSP-Wisconsin	PSCo	SPS
Quantity	356	201	229	433

Natural gas utility mains at Dec. 31, 2014:

Miles	NSP-Minnesota	NSP-Wisconsin	PSCo	WGI
Transmission	136	—	2,258	11
Distribution	9,931	2,316	21,844	—

Item 3 — Legal Proceedings

Xcel Energy is involved in various litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or is a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Management maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of a reasonably possible loss in certain situations, including but not limited to when (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Additional Information

See Note 13 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Item 1, Item 7 and Note 12 to the consolidated financial statements for a discussion of proceedings involving utility rates and other regulatory matters.

Item 4 — Mine Safety Disclosures

None.

PART II

Item 5 — Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Quarterly Stock Data

Xcel Energy Inc.'s common stock is listed on the New York Stock Exchange (NYSE). The trading symbol is XEL. The number of common shareholders of record as of Dec. 31, 2014 was approximately 67,716. The following are the high and low stock prices based on the NYSE Composite Transactions for the quarters of 2014 and 2013 and the dividends declared per share during those quarters. See Item 7 and Note 4 to the consolidated financial statements for further discussion of Xcel Energy Inc.'s dividend policy.

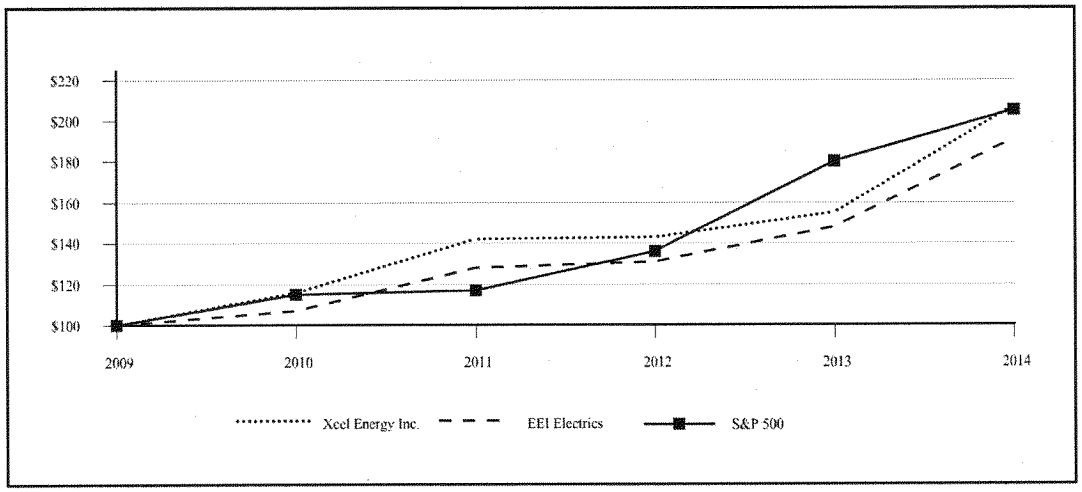
2014	High	Low	Dividends
First quarter	$ 30.77	$ 27.27	$ 0.3000
Second quarter	32.37	29.83	0.3000
Third quarter	32.48	29.60	0.3000
Fourth quarter	37.58	30.18	0.3000

2013	High	Low	Dividends
First quarter	$ 29.74	$ 26.77	$ 0.2700
Second quarter	31.79	27.38	0.2800
Third quarter	30.41	26.90	0.2800
Fourth quarter	29.40	27.14	0.2800

The following compares our cumulative TSR on common stock with the cumulative total return of the EEI Investor-Owned Electrics Index and the S&P's 500 Composite Stock Price Index over the last five years (assuming a $100 investment on Dec. 31, 2009, and the reinvestment of all dividends).

The EEI Investor-Owned Electrics Index currently includes 48 companies and is a broad measure of industry performance.

COMPARISON OF FIVE YEAR CUMULATIVE TOTAL RETURN*
Among Xcel Energy Inc., the EEI Investor-Owned Electrics
and the S&P 500



* $100 invested on Dec. 31, 2009 in stock or index — including reinvestment of dividends. Fiscal years ending Dec. 31.

	2009	2010	2011	2012	2013	2014
Xcel Energy Inc.	$ 100	$ 116	$ 142	$ 143	$ 155	$ 207
EEI Investor-Owned Electrics	100	107	128	131	148	191
S&P 500	100	115	117	136	180	205

Securities Authorized for Issuance Under Equity Compensation Plans

Information required under Item 5 — Securities Authorized for Issuance Under Equity Compensation Plans is contained in Xcel Energy Inc.'s Proxy Statement for its 2015 Annual Meeting of Shareholders, which is incorporated by reference.

UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

The following table provides information about our purchases of equity securities that are registered by Xcel Energy Inc. pursuant to Section 12 of the Exchange Act for the year ended Dec. 31, 2014:

	Issuer Purchases of Equity Securities			
Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares That May Yet Be Purchased Under the Plans or Programs
Jan. 1, 2014 — Jan. 31, 2014 [a]	18,874	$ 28.11	—	—
Feb. 1, 2014 — Dec. 31, 2014	—	—	—	—
Total	18,874		—	—

[a] Xcel Energy Inc. or one of its agents periodically purchases common shares in order to satisfy obligations under the Stock Equivalent Plan for Non-Employee Directors.

Item 6 — Selected Financial Data

(Millions of Dollars, Thousands of Shares, Except Per Share Data)	2014	2013	2012	2011	2010
Operating revenues	$ 11,686	$ 10,915	$ 10,128	$ 10,655	$ 10,311
Operating expenses	9,738	9,067	8,306	8,873	8,691
Net income	1,021	948	905	841	756
Earnings available to common shareholders	1,021	948	905	834	752
Weighted average common shares outstanding:					
Basic	503,847	496,073	487,899	485,039	462,052
Diluted	504,117	496,532	488,434	485,615	463,391
EPS:					
Basic	$ 2.03	$ 1.91	$ 1.86	$ 1.72	$ 1.63
Diluted	2.03	1.91	1.85	1.72	1.62
Dividends declared per common share	1.20	1.11	1.07	1.03	1.00
Total assets	36,958	33,907	31,141	29,497	27,388
Long-term debt [a]	11,500	10,911	10,144	8,849	9,263
Book value per share	20.20	19.21	18.19	17.44	16.76
Return on average common equity	10.3%	10.3%	10.4%	10.1%	9.8%
Ratio of earnings to fixed charges [b]	3.3	3.1	2.8	2.8	2.7
Non-GAAP:					
Ongoing earnings [c]	$ 1,021	$ 968	$ 888	$ 841	$ 756

[a] Includes capital lease obligations.
[b] See Exhibit 12.01.
[c] See Item 7 for a reconciliation of ongoing earnings to GAAP earnings.

Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations

Business Segments and Organizational Overview

Xcel Energy Inc. is a public utility holding company. Xcel Energy's operations included the activity of four utility subsidiaries that serve electric and natural gas customers in eight states. These utility subsidiaries are NSP-Minnesota, NSP-Wisconsin, PSCo and SPS. These utilities serve customers in portions of Colorado, Michigan, Minnesota, New Mexico, North Dakota, South Dakota, Texas and Wisconsin. Along with the TransCo subsidiaries, WYCO, a joint venture formed with CIG to develop and lease natural gas pipelines, storage and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the regulated utility operations.

Xcel Energy Inc.'s nonregulated subsidiary is Eloigne, which invests in rental housing projects that qualify for low-income housing tax credits.

Forward-Looking Statements

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including the 2015 EPS 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 to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slowdown 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; cyber security threats and data security breaches; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the NRC; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Operations; and the other risk factors listed from time to time by Xcel Energy Inc. in reports filed with the SEC, including "Risk Factors" in Item 1A of this Annual Report on Form 10-K and Exhibit 99.01 hereto.

Management's Strategic Plans

Xcel Energy's corporate strategy focuses on the following primary objectives:

- Improving utility performance;
- Driving operational excellence;
- Providing options and solutions to customers; and
- Investing for the future.

These objectives are designed to provide our investors an attractive total return and our customers with clean, safe, reliable energy at a competitive price. Below is a discussion of these objectives and how they support our overall strategy.

Improving utility performance

Xcel Energy is made up of several utility operating companies. As part of the regulatory process, each state will generally establish an authorized ROE. In many of our states, our utility operating companies are earning less than the authorized ROE. This is referred to as an ROE gap. An ROE gap can be a result of numerous factors including the timing of implementation of new rates, timing of capital investments, a regulatory commission not allowing the recovery of certain costs, the time period used as test year for rate cases, fluctuations in sales, the impact of weather, unanticipated cost increases, etc. Xcel Energy is focused on closing this gap over the next several years. As a result, we have established the following goals:

- Close the ROE gap by 50 basis points by 2018; and
- Derive 75 percent of our revenue from multi-year plans by 2017.

We are pursuing regulatory and legislative changes to streamline rate case proceedings and optimize recovery, while improving our alignment with state policies and keeping pace with evolving customer preferences.

Driving operational excellence

Managing our operational performance and satisfying our customers has, and will continue to be, a fundamental priority. However, operational excellence also includes managing costs. By building on past success, leveraging technology, managing risks and continuously striving to improve our processes, we can bend the cost curve downward. Over the next five years, Xcel Energy is planning to implement cost saving measures which are intended to align increases in O&M expense more closely to sales growth. Our financial objective is to slow our annual O&M expense growth to approximately zero percent to two percent. However, we will not sacrifice reliability or safety to meet this initiative.

In addition, 50 percent of our workforce will be eligible to retire in the next ten years. Managing this workforce transition is key to our operational excellence objective.

Providing options and solutions to customers

Adapting to a changing environment is critical to our success. Our customers expect to be offered choices and we are committed to providing options and solutions that are fair and satisfy their needs. Environmental leadership is a core priority and is designed to meet customer and policy maker expectations for clean energy at a competitive price while creating shareholder value. We will continue to offer and expand our production of renewable energy, including wind and solar alternatives, and further develop DSM, conservation and renewable programs.

Investing for the future

Sound investments today are necessary for tomorrow's success. Our base capital expenditures are projected to be approximately $14.5 billion from 2015 through 2019. This capital forecast will grow rate base at a compounded average annual rate of approximately 4.7 percent. Our capital investment plan includes needed investments in transmission, adding new generation, reducing emissions in our power plants, refreshing our infrastructure, improving reliability, replacing natural gas pipelines and increasing the levels of renewable energy on our system. In addition to our base capital investment plan, we are looking at potential incremental investments in natural gas assets and transmission projects through our recently established independent TransCos.

Xcel Energy has a proven track record of making sound investments. We proactively made the decision to balance our generation portfolio and expand our alternative energy production. Our customers, stakeholders and the environment are currently benefiting from these decisions and will continue to do so in the future.

Providing an attractive total return

Successful execution of our strategic plan should allow Xcel Energy to deliver an attractive total return for our shareholders. Through a combination of earnings growth and dividend yield, we plan to:

- Deliver long-term annual EPS growth of four percent to six percent, based on a weather-normalized 2014 EPS of $2.00;
- Deliver annual dividend increases of five percent to seven percent;
- Target a dividend payout ratio of 60 to 70 percent of annual ongoing EPS; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

We have successfully achieved our prior financial objectives, meeting or exceeding our earnings guidance range for ten consecutive years and believe we are positioned to continue to achieve our value proposition. Our ongoing earnings have grown approximately 6.5 percent and our dividend has grown approximately 3.8 percent annually from 2005 through 2014. Prior to 2014, our objective was to grow the dividend two to four percent annually. In addition, our current senior unsecured debt credit ratings for Xcel Energy and its utility subsidiaries are in the BBB+ to A range.

Financial Review

The following discussion and analysis by management focuses on those factors that had a material effect on Xcel Energy's financial condition, results of operations and cash flows during the periods presented, or are expected to have a material impact in the future. It should be read in conjunction with the accompanying consolidated financial statements and the related notes to consolidated financial statements.

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary as well as the ROE of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS and ongoing ROE for Xcel Energy and by subsidiary are financial measures not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain nonrecurring items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Ongoing ROE is calculated by dividing the net income or loss attributable to the controlling interest of Xcel Energy or each subsidiary, adjusted for certain nonrecurring items, by each entity's average common stockholders' or stockholder's equity. We use these non-GAAP financial measures to evaluate and provide details of earnings results. We believe these measurements are useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. These non-GAAP financial measures should not be considered as alternatives to measures calculated and reported in accordance with GAAP.

Results of Operations

The following table summarizes the diluted EPS for Xcel Energy:

Diluted Earnings (Loss) Per Share	2014	2013	2012
PSCo	$ 0.90	$ 0.91	$ 0.90
NSP-Minnesota	0.80	0.79	0.70
SPS	0.26	0.23	0.22
NSP-Wisconsin	0.14	0.12	0.10
Equity earnings of unconsolidated subsidiaries	0.04	0.04	0.04
Regulated utility	2.14	2.09	1.96
Xcel Energy Inc. and other	(0.11)	(0.14)	(0.14)
Ongoing diluted EPS	**2.03**	**1.95**	**1.82**
SPS FERC complaint case orders	—	(0.04)	—
Prescription drug tax benefit	—	—	0.03
GAAP diluted EPS	**$ 2.03**	**$ 1.91**	**$ 1.85**

Ongoing earnings exclude adjustments for certain items. For 2013, the adjustment to GAAP earnings is related to the SPS FERC complaint case orders. For 2012, the adjustment is related to the Patient Protection and Affordable Care Act. See below under Adjustments to GAAP Earnings and Note 12 and Note 6 to the consolidated financial statements for further discussion, respectively, for the 2013 and 2012 adjustments.

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, in determining whether performance targets are met for performance-based compensation, and when communicating its earnings outlook to analysts and investors.

2013 Adjustment to GAAP Earnings

SPS FERC Orders — As a result of the orders issued in August 2013 by the FERC for a potential SPS customer refund, a pre-tax charge of $36 million was recorded in 2013. Of this amount, approximately $30 million ($26 million revenue reduction and $4 million of interest) was attributable to periods prior to 2013 and not representative of ongoing earnings. As such, GAAP earnings include the total after tax amount of $24.4 million and ongoing earnings exclude $20.2 million. See Note 12 to the consolidated financial statements for further discussion.

2012 Adjustment to GAAP Earnings

Prescription drug tax benefit — 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, or $0.03 per share, of income tax benefit. See Note 6 to the consolidated financial statements for further discussion.

Earnings Adjusted for Certain Items (Ongoing EPS)

2014 Comparison with 2013

Xcel Energy — Overall, ongoing earnings increased $0.08 per share for 2014. Ongoing earnings increased as a result of higher electric and natural gas margins due to rate increases in various jurisdictions, weather-normalized sales growth and lower interest charges. These positive factors were partially offset by the unfavorable impact of milder weather, as well as higher expected O&M expenses, property taxes and depreciation. 2013 GAAP earnings include a $0.04 per share charge for a potential SPS customer refund based on FERC orders issued in August 2013. This item was excluded from 2013 ongoing earnings.

PSCo — PSCo's ongoing earnings decreased $0.01 per share for 2014. Higher natural gas and electric margins primarily due to rate increases, higher AFUDC, lower O&M expenses and weather-normalized sales growth were offset by higher property taxes, depreciation, accruals associated with the electric earnings test refund obligations and the unfavorable impact of weather.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.01 per share for 2014. Ongoing earnings were positively impacted by electric rate increases in Minnesota (interim, subject to refund) and North Dakota and weather-normalized sales growth. These items were partially offset by higher O&M expenses, the unfavorable impact of weather, lower AFUDC, increased property taxes and interest charges.

SPS — SPS' ongoing earnings increased $0.03 per share for 2014. Electric rate increases in Texas and New Mexico and weather-normalized sales growth offset higher O&M and depreciation expenses.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.02 per share for 2014. An electric rate increase led to higher electric margin, while weather-normalized sales growth positively impacted both electric and natural gas margins. These increases were partially offset by additional O&M expenses.

Xcel Energy Inc. and other — Xcel Energy Inc. and other includes financing costs at the holding company and other items. Earnings improved by $0.03 per share for 2014, largely due to lower financing costs as a result of the refinancing of junior subordinated notes.

2013 Comparison with 2012

Xcel Energy — Overall, ongoing earnings increased $0.13 per share for 2013. Ongoing earnings increased as a result of higher electric and gas margins due to rate increases in various states, the impact of favorable colder weather on the natural gas business and reduced interest charges. These positive factors were partially offset by planned increases in O&M expenses and depreciation.

PSCo — PSCo's ongoing earnings increased $0.01 per share for 2013. Ongoing earnings increased as a result of higher gas and electric margins primarily due to rate increases, the impact of cooler weather on natural gas margins and lower interest charges, partially offset by higher depreciation, O&M expenses and customer refunds related to the 2013 electric earnings test refund obligation.

NSP-Minnesota — NSP-Minnesota's ongoing earnings increased $0.09 per share for 2013. Ongoing earnings were positively impacted by electric rate increases in Minnesota and South Dakota, interim rates subject to refund in North Dakota, the impact of cooler winter weather and lower interest charges. These items were partially offset by higher O&M expenses.

SPS — SPS' ongoing earnings increased $0.01 per share for 2013. Electric rate increases in Texas and the gain associated with the sale of certain transmission assets to Sharyland were partially offset by higher depreciation.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings increased $0.02 per share for 2013. Higher ongoing earnings from electric and natural gas rates and cooler winter weather were partially offset by higher O&M expenses and depreciation.

Changes in Diluted EPS

The following table summarizes significant components contributing to the changes in 2014 EPS compared with the same period in 2013.

Diluted Earnings (Loss) Per Share	Dec. 31
2013 GAAP diluted EPS	**$ 1.91**
SPS FERC complaint case orders	0.04
2013 ongoing diluted EPS	**1.95**
Components of change — 2014 vs. 2013	
Higher electric margins (excludes 2013 impact of SPS FERC complaint case orders)	0.26
Higher natural gas margins	0.06
Lower interest charges (excludes 2013 impact of SPS FERC complaint case orders)	0.01
Higher O&M expenses	(0.07)
Higher taxes (other than income taxes)	(0.06)
Higher depreciation and amortization	(0.05)
Higher conservation and DSM program expenses	(0.05)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.03)
Other, net	0.01
2014 ongoing and GAAP diluted EPS	**$ 2.03**

Diluted Earnings (Loss) Per Share	Dec. 31
2012 GAAP diluted EPS	**$ 1.85**
Prescription drug tax benefit	(0.03)
2012 ongoing diluted EPS	**1.82**
Components of change — 2013 vs. 2012	
Higher electric margins (excludes impact of SPS FERC complaint case orders)	0.18
Higher natural gas margins	0.08
Higher AFUDC — equity	0.05
Lower interest charges (excludes impact of SPS FERC complaint case orders)	0.04
Gain on sale of transmission assets (included in O&M expenses)	0.02
Higher O&M expenses (excludes gain on sale of transmission assets)	(0.14)
Higher depreciation and amortization	(0.06)
Dilution from at-the-market program, direct stock purchase plan and benefit plans	(0.03)
Higher taxes (other than income taxes)	(0.01)
2013 ongoing diluted EPS	**1.95**
SPS FERC complaint case orders	(0.04)
2013 GAAP diluted EPS	**$ 1.91**

The following table summarizes the ROE for Xcel Energy and its utility subsidiaries:

ROE — 2014	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2014 ongoing and GAAP ROE	9.40%	8.82%	8.88%	10.85%	10.33%

ROE — 2013	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2013 ongoing ROE	9.66%	9.24%	9.03%	10.61%	10.50%
SPS FERC complaint case orders	—	—	(1.54)	—	(0.22)
2013 GAAP ROE	9.66%	9.24%	7.49%	10.61%	10.28%

ROE - 2012	PSCo	NSP-Minnesota	SPS	NSP-Wisconsin	Xcel Energy
2012 ongoing ROE	9.92%	8.77%	9.44%	9.62%	10.24%
Prescription drug tax benefit	0.38	—	—	—	0.19
2012 GAAP ROE	10.30%	8.77%	9.44%	9.62%	10.43%

The following tables provide reconciliations of ongoing to GAAP earnings (net income) and ongoing to GAAP diluted EPS for the years ended Dec. 31:

(Millions of Dollars)	2014	2013	2012
Ongoing earnings	$ 1,021.3	$ 968.4	$ 888.3
SPS FERC complaint case orders (2013) and prescription drug tax benefit (2012)	—	(20.2)	16.9
GAAP earnings	$ 1,021.3	$ 948.2	$ 905.2

Diluted Earnings (Loss) Per Share	2014	2013	2012
Ongoing diluted EPS	$ 2.03	$ 1.95	$ 1.82
SPS FERC complaint case orders (2013) and prescription drug tax benefit (2012)	—	(0.04)	0.03
GAAP diluted EPS	$ 2.03	$ 1.91	$ 1.85

The following tables summarize the earnings contributions of Xcel Energy's business segments:

(Millions of Dollars)	2014	2013	2012
GAAP income (loss) by segment			
Regulated electric income	$ 890.5	$ 850.7	$ 851.9
Regulated natural gas income	128.6	123.7	98.1
Other [(a)]	59.5	44.6	22.1
Xcel Energy Inc. and other costs [(a)]	(57.3)	(70.8)	(66.9)
Total net income	$ 1,021.3	$ 948.2	$ 905.2

Contributions to Diluted Earnings (Loss) Per Share	2014	2013	2012
GAAP earnings (loss) by segment			
Regulated electric	$ 1.77	$ 1.71	$ 1.74
Regulated natural gas	0.25	0.25	0.20
Other [(a)]	0.12	0.09	0.05
Xcel Energy Inc. and other costs [(a)]	(0.11)	(0.14)	(0.14)
Total diluted EPS	$ 2.03	$ 1.91	$ 1.85

(a) Not a reportable segment. Included in all other segment results in Note 17 to the consolidated financial statements.

Statement of Income Analysis

The following discussion summarizes the items that affected the individual revenue and expense items reported in the consolidated statements of income.

Estimated Impact of Temperature Changes on Regulated Earnings — Unusually hot summers or cold winters increase electric and natural gas sales, while mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

Degree-day or Temperature-Humidity Index (THI) data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature and humidity. Heating degree-days (HDD) is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65° Fahrenheit. Cooling degree-days (CDD) is the measure of the variation in the weather based on the extent to which the average daily temperature rises above 65° Fahrenheit. Each degree of temperature above 65° Fahrenheit is counted as one cooling degree-day, and each degree of temperature below 65° Fahrenheit is counted as one heating degree-day. In Xcel Energy's more humid service territories, a THI is used in place of CDD, which adds a humidity factor to CDD. HDD, CDD and THI are most likely to impact the usage of Xcel Energy's residential and commercial customers. Industrial customers are less sensitive to weather.

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction, based on regulatory practice. To calculate the impact of weather on demand, a demand factor is applied to the weather impact on sales as defined above to derive the amount of demand associated with the weather impact.

The percentage increase (decrease) in normal and actual HDD, CDD and THI are provided in the following table:

	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2012 vs. Normal	2013 vs. 2012
HDD	7.8%	6.5%	0.4%	(15.9)%	25.8%
CDD	(2.6)	24.7	(20.3)	46.1	(13.6)
THI	(11.9)	21.8	(24.2)	36.1	(9.7)

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

	2014 vs. Normal	2013 vs. Normal	2014 vs. 2013	2012 vs. Normal	2013 vs. 2012
Retail electric	$ 0.010	$ 0.088	$ (0.078)	$ 0.081	$ 0.007
Firm natural gas	0.019	0.021	(0.002)	(0.033)	0.054
Total	$ 0.029	$ 0.109	$ (0.080)	$ 0.048	$ 0.061

Sales Growth (Decline) — The following tables summarize Xcel Energy and its utility subsidiaries' sales growth (decline) for actual and weather-normalized sales for the years ended Dec. 31, compared with the previous year:

	2014 vs. 2013				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	(1.8)%	(0.3)%	(0.4)%	(2.8)%	(1.6)%
Electric C&I	1.0	4.2	2.5	0.3	—
Total retail electric sales	0.2	2.8	1.8	(0.7)	(0.5)
Firm natural gas sales	2.3	7.4	N/A	(0.7)	7.3

	2014 vs. 2013				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	0.5%	0.5%	0.4%	0.3%	0.7%
Electric C&I	1.7	4.4	2.8	1.6	0.6
Total retail electric sales	1.3	3.3	2.3	1.2	0.6
Firm natural gas sales	4.6	3.8	N/A	5.2	3.6

Weather-normalized Electric Growth

- NSP-Wisconsin's electric sales growth was largely due to strong sales to large C&I customers primarily in the oil, gas and sand mining industries.
- SPS' C&I growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area.
- PSCo's electric sales growth was primarily due to customers in the food manufacturing, fracking and mining industries.
- NSP-Minnesota's electric sales growth was led by an increased number of customers for both residential and small C&I, as well as higher use per customer in small C&I.

Weather-normalized Natural Gas Growth

- Across our natural gas service territories, strong sales were experienced in 2014, which continued the trend that began in the last half of 2013.

Weather-normalized sales for 2015 are projected to increase approximately 1.0 percent for retail electric customers and to decline approximately 2.0 percent for retail firm natural gas customers.

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual (Without 2012 Leap Day)					
Electric residential	1.4%	3.9%	0.9%	1.1%	1.3%
Electric C&I	0.3	1.0	1.8	0.3	(0.7)
Total retail electric sales	0.6	1.9	1.5	0.5	(0.1)
Firm natural gas sales	21.9	30.0	N/A	17.8	29.1

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized (Without 2012 Leap Day)					
Electric residential	0.5%	0.5%	0.7%	1.3%	(0.2)%
Electric C&I	0.4	0.9	2.1	0.9	(1.1)
Total retail electric sales	0.4	0.8	1.7	1.0	(0.8)
Firm natural gas sales	3.8	5.9	N/A	3.3	4.2

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Actual					
Electric residential	1.1%	3.6%	0.6%	0.8%	1.1%
Electric C&I	—	0.7	1.5	—	(1.0)
Total retail electric sales	0.3	1.6	1.3	0.3	(0.4)
Firm natural gas sales	21.3	29.4	N/A	17.3	28.5

	2013 vs. 2012				
	Xcel Energy	NSP-Wisconsin	SPS	PSCo	NSP-Minnesota
Weather-normalized					
Electric residential	0.2%	0.2%	0.5%	1.0%	(0.5)%
Electric C&I	0.1	0.6	1.8	0.7	(1.4)
Total retail electric sales	0.1	0.5	1.5	0.7	(1.1)
Firm natural gas sales	3.3	5.3	N/A	2.8	3.7

Electric Revenues and Margin

Electric revenues and fuel and purchased power expenses are largely impacted by the fluctuation in the price of natural gas, coal and uranium used in the generation of electricity, but as a result of the design of fuel recovery mechanisms to recover current expenses, these price fluctuations have minimal impact on electric margin. The following table details the electric revenues and margin:

(Millions of Dollars)	2014	2013	2012
Electric revenues	$ 9,466	$ 9,034	$ 8,517
Electric fuel and purchased power	(4,210)	(4,019)	(3,624)
Electric margin	$ 5,256	$ 5,015	$ 4,893

The following tables summarize the components of the changes in electric revenues and electric margin for the years ended Dec. 31:

Electric Revenues

(Millions of Dollars)	2014 vs. 2013
Retail rate increases [a]	$ 129
Trading	100
Fuel and purchased power cost recovery	78
Non-fuel riders	57
Transmission revenue	48
Conservation and DSM program revenues (offset by expenses)	44
Retail sales growth, excluding weather impact	24
Estimated impact of weather	(60)
Other, net	(14)
Total increase in ongoing electric revenues	406
SPS FERC complaint case orders [b]	26
Total increase in GAAP electric revenues	$ 432

2014 Comparison with 2013 — Electric revenues increased primarily due to various rate increases across all of the utility subsidiaries, higher trading and increased fuel and purchased power cost recovery, which is offset in operating expense.

Electric Margin

(Millions of Dollars)	2014 vs. 2013
Retail rate increases [a]	$ 129
Non-fuel riders	57
Conservation and DSM program revenues (offset by expenses)	44
Transmission revenue, net of costs	31
Retail sales growth, excluding weather impact	24
NSP-Wisconsin fuel recovery	11
Estimated impact of weather	(60)
Firm wholesale	(6)
Other, net	(15)
Total increase in ongoing electric margin	215
SPS FERC complaint case orders [b]	26
Total increase in GAAP electric margin	$ 241

(a) The retail rate increases include final rates in Texas, Colorado (net of estimated earnings test refund obligations), New Mexico, Wisconsin and North Dakota and interim rates in Minnesota, subject to and net of estimated provision for refund. See Note 12 to the consolidated financial statements.

(b) As a result of two orders issued by the FERC in August 2013, a pretax charge of approximately $36 million ($32 million in electric revenues, of which $6 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in 2013. See Note 12 to the consolidated financial statements.

2014 Comparison to 2013 — The increase in electric margin was primarily due to the various rate increases across all of the utility subsidiaries.

Electric Revenues

(Millions of Dollars)	2013 vs. 2012
Fuel and purchased power cost recovery	$ 360
Retail rate increases [a]	229
Transmission revenue	68
Non-fuel riders	18
Estimated impact of weather	7
PSCo earnings test refund obligation	(43)
Firm wholesale	(36)
Conservation and DSM program incentives	(24)
Trading	(19)
SPS FERC complaint case orders [b]	(6)
Other, net	(11)
Total increase in ongoing electric revenues	543
SPS FERC complaint case orders [b]	(26)
Total increase in GAAP electric revenues	$ 517

2013 Comparison with 2012 — Electric revenues increased primarily due to higher fuel and purchased power cost recovery, which is offset in operating expense, and various rate increases across all of the utility subsidiaries.

Electric Margin

(Millions of Dollars)	2013 vs. 2012
Retail rate increases [a]	$ 229
Transmission revenue, net of costs	36
Non-fuel riders	18
Estimated impact of weather	7
PSCo earnings test refund obligation	(43)
Conservation and DSM program incentives	(24)
Firm wholesale	(24)
Trading margin	(12)
SPS FERC complaint case orders [b]	(6)
Other, net	(33)
Total increase in ongoing electric margin	148
SPS FERC complaint case orders [b]	(26)
Total increase in GAAP electric margin	$ 122

(a) The retail rate increases include final rates in Minnesota, Colorado, Wisconsin, South Dakota and Texas and interim rates, subject to refund, in North Dakota. The Minnesota rate increase is net of a provision for customer refunds of $131 million for the twelve months ended Dec. 31, 2013 based on the final rate order received for the 2013 electric rate case. Due to the order, there was a reduction in revenues and expenses of approximately $40 million, primarily related to depreciation of $32 million and O&M expense of $8 million in 2013.

(b) As a result of two orders issued by the FERC in August 2013, a pretax charge of approximately $36 million ($32 million in electric revenues, of which $6 million relates to 2013 and $26 million relates to periods prior to 2013, and $4 million in interest charges) was recorded in 2013. See Note 12 to the consolidated financial statements.

2013 Comparison to 2012 — The increase in electric margin was primarily due to the various rate increases across all of the utility subsidiaries.

Natural Gas Revenues and Margin

Total natural gas expense tends to vary with changing sales requirements and the cost of natural gas purchases. However, due to the design of purchased natural gas cost recovery mechanisms to recover current expenses for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin. The following table details natural gas revenues and margin:

(Millions of Dollars)	2014	2013	2012
Natural gas revenues	$ 2,143	$ 1,805	$ 1,537
Cost of natural gas sold and transported	(1,372)	(1,083)	(881)
Natural gas margin	$ 771	$ 722	$ 656

The following tables summarize the components of the changes in natural gas revenues and natural gas margin for the years ended Dec. 31:

Natural Gas Revenues

(Millions of Dollars)	2014 vs. 2013
Purchased natural gas adjustment clause recovery	$ 293
Retail rate increases (Colorado)	19
PSIA rider (Colorado)	14
Retail sales growth, excluding weather impact	10
Estimated impact of weather	(1)
Other, net	3
Total increase in natural gas revenues	$ 338

2014 Comparison to 2013 — Natural gas revenues increased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2014 vs. 2013
Retail rate increases (Colorado)	$ 19
PSIA rider (Colorado), partially offset in O&M expenses	14
Retail sales growth, excluding weather impact	10
Estimated impact of weather	(1)
Other, net	7
Total increase in natural gas margin	$ 49

2014 Comparison to 2013 — Natural gas margins increased primarily due to rate increases and the PSIA in Colorado.

Natural Gas Revenues

(Millions of Dollars)	2013 vs. 2012
Purchased natural gas adjustment clause recovery	$ 198
Estimated impact of weather	42
Retail rate increases (Colorado and Wisconsin)	15
Retail sales growth	9
Conservation and DSM program incentives	5
Conservation and DSM program revenues (offset by expenses)	4
Other, net	(5)
Total increase in natural gas revenues	$ 268

2013 Comparison to 2012 — Natural gas revenues increased primarily due to the purchased natural gas adjustment clause recovery, which is offset in operating expense.

Natural Gas Margin

(Millions of Dollars)	2013 vs. 2012
Estimated impact of weather	$ 42
Retail rate increases (Colorado and Wisconsin)	15
Retail sales growth	9
Conservation and DSM program incentive	5
Conservation and DSM program revenues (offset by expenses)	4
Other, net	(9)
Total increase in natural gas margin	$ 66

2013 Comparison to 2012 — Natural gas margins increased primarily due to cooler winter weather and rate increases in Colorado and Wisconsin.

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $60.8 million, or 2.7 percent, for 2014 compared with 2013, and $97.4 million, or 4.5 percent, for 2013 compared with 2012. The following tables summarize the changes in O&M expenses:

(Millions of Dollars)	2014 vs. 2013
Nuclear plant operations and amortization	$ 36
2013 gain on sale of transmission assets	14
Transmission costs	4
Electric and natural gas distribution expenses	1
Employee benefits	(6)
Plant generation costs	(3)
Other, net	15
Total increase in O&M expenses	$ 61

2014 Comparison to 2013 — The increase in O&M expenses for 2014 was largely driven by the following:

- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants; and
- Gain on sale of transmission assets relates to the 2013 gain associated with the sale of certain SPS' transmission assets to Sharyland.

(Millions of Dollars)	2013 vs. 2012
Electric and gas distribution expenses	$ 44
Nuclear plant operations and amortization	33
Transmission costs	13
Employee benefits	7
Gain on sale of transmission assets	(14)
Other, net	14
Total increase in O&M expenses	$ 97

2013 Comparison to 2012 — The increase in O&M expenses for 2013 was largely driven by the following:

- Electric and gas distribution expenses were primarily driven by increased maintenance activities due to vegetation management, storms and outages;
- Nuclear cost increases are related to the amortization of prior outages and initiatives designed to improve the operational efficiencies of the plants;
- Increased transmission costs were related to higher substation maintenance expenditures and reliability costs;
- Higher employee benefits related primarily to increased pension expense; and
- See Note 12 to the consolidated financial statements for further discussion of the gain on sale of transmission assets.

Conservation and DSM Program Expenses — Conservation and DSM program expenses increased $41.0 million, or 15.7 percent, for 2014 compared with 2013. The increase was primarily attributable to higher electric recovery rates 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 $41.2 million, or 4.2 percent, for 2014 compared with 2013. The increase was primarily attributable to the PI steam generator replacement placed in service in December 2013 and normal system expansion, partially offset by additional accelerated amortization of the excess depreciation reserve associated with certain Minnesota assets. See further discussion within Note 12 to the consolidated financial statements.

Depreciation and amortization increased $51.8 million, or 5.6 percent, for 2013 compared with 2012. The increase is primarily attributable to normal system expansion, which was partially offset by reductions related to the final rate order received for the 2013 Minnesota electric rate case that reduced depreciation expense by approximately $32 million for 2013.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $45.3 million, or 10.8 percent, for 2014 compared with 2013. The increase was primarily due to higher property taxes in Colorado, Minnesota and Texas.

Taxes (other than income taxes) increased $11.6 million, or 2.8 percent, for 2013 compared with 2012. The annual increase is due to higher property taxes primarily in Colorado and Texas.

AFUDC, Equity and Debt — AFUDC increased $1.3 million for 2014 compared with 2013. The increase was primarily due to construction related to the CACJA and the expansion of transmission facilities, partially offset by the portion of the Monticello LCM/EPU placed in service in July 2013 and the PI steam generator replacement placed in service in December 2013.

AFUDC increased $28.7 million for 2013 compared with 2012. The increase is primarily due to construction related to the CACJA and the expansion of transmission facilities.

Interest Charges — Interest charges decreased $8.6 million, or 1.5 percent, for 2014 compared with 2013. The decrease was primarily due to refinancings at lower interest rates, partially offset by higher long-term debt levels. In addition, interest charges in 2013 reflected $4 million of interest associated with the customer refund at SPS based on a FERC order, interest on customer refunds in Minnesota and the write off of $6.3 million of unamortized debt expense related to the junior subordinated notes called in May 2013.

Interest charges decreased $26.4 million, or 4.4 percent, for 2013 compared with 2012. The decrease is primarily due to refinancings at lower interest rates. This was partially offset by higher long-term debt levels, $4 million of interest associated with the customer refund at SPS based on the August 2013 FERC orders, $5 million of interest associated with customer refunds in Minnesota for the 2013 electric rate case 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 increased $39.8 million for 2014 compared with 2013. The increase was primarily due to higher 2014 pretax earnings and recognition of additional R&E credits in 2013. These were partially offset by a 2014 tax benefit for prior year adjustments. The ETR was 33.9 percent for 2014 compared with 33.8 percent for 2013. See Note 6 to the consolidated financial statements for further discussion.

Income tax expense increased $33.8 million for 2013 compared with 2012. The increase in income tax expense was primarily due to higher pretax earnings in 2013, a tax benefit for a carryback in 2012 and for the restoration in 2012 of a portion of the tax benefit associated with federal subsidies for prescription drug plans that was previously written off in 2010. These were partially offset in 2013 by a tax benefit for a carryback claim related to 2013, R&E credits and increased permanent plant-related reductions. The ETR was 33.8 percent for 2013 compared with 33.2 percent for 2012. The higher ETR for 2013 was primarily due to the adjustments referenced above. See Note 6 to the consolidated financial statements for further discussion.

Xcel Energy Inc. and Other Results

The following tables summarize the net income and EPS contributions of Xcel Energy Inc. and its nonregulated businesses:

	Contribution to Xcel Energy's Earnings		
(Millions of Dollars)	2014	2013	2012
Xcel Energy Inc. financing costs	$ (51.8)	$ (62.9)	$ (71.5)
Eloigne [a]	(0.5)	(0.8)	3.8
Xcel Energy Inc. taxes and other results	(5.0)	(7.1)	0.8
Total Xcel Energy Inc. and other costs	$ (57.3)	$ (70.8)	$ (66.9)

	Contribution to Xcel Energy's EPS		
(Earnings per Share)	2014	2013	2012
Xcel Energy Inc. financing costs	$ (0.10)	$ (0.13)	$ (0.15)
Eloigne [a]	—	—	0.01
Xcel Energy Inc. taxes and other results	(0.01)	(0.01)	—
Total Xcel Energy Inc. and other costs	$ (0.11)	$ (0.14)	$ (0.14)

[a] Amounts include gains or losses associated with sales of properties held by Eloigne.

Xcel Energy Inc.'s results include interest charges, which are incurred at Xcel Energy Inc. and are not directly assigned to individual subsidiaries.

Factors Affecting Results of Operations

Xcel Energy's utility revenues depend on customer usage, which varies with weather conditions, general business conditions and the cost of energy services. Various regulatory agencies approve the prices for electric and natural gas service within their respective jurisdictions and affect Xcel Energy's ability to recover its costs from customers. The historical and future trends of Xcel Energy's operating results have been, and are expected to be, affected by a number of factors, including those listed below.

General Economic Conditions

Economic conditions may have a material impact on Xcel Energy's operating results. While economic growth has been improving over the past year, management cannot predict whether this trend will be sustained going forward. Other events impact overall economic conditions and management cannot predict the impact of fluctuating energy prices, terrorist activity, war or the threat of war. However, Xcel Energy could experience a material impact to its results of operations, future growth or ability to raise capital resulting from a sustained general slowdown in economic growth or a significant increase in interest rates.

Fuel Supply and Costs

Xcel Energy Inc.'s operating utilities have varying dependence on coal, natural gas and uranium. Changes in commodity prices are generally recovered through fuel recovery mechanisms and have very little impact on earnings. However, availability of supply, the potential implementation of a carbon tax or emissions-related generation restrictions and unanticipated changes in regulatory recovery mechanisms could impact our operations. See Item 1 for further discussion of fuel supply and costs.

Pension Plan Costs and Assumptions

Xcel Energy has significant net pension and postretirement benefit costs that are measured using actuarial valuations. Inherent in these valuations are key assumptions including discount rates and expected return on plan assets. Xcel Energy evaluates these key assumptions at least annually by analyzing current market conditions, which include changes in interest rates and market returns. Changes in the related net pension and postretirement benefits costs and funding requirements may occur in the future due to changes in assumptions. The payout of a significant percentage of pension plan liabilities in a single year due to high retirements or employees leaving the company would trigger settlement accounting and could require the company to recognize material incremental pension expense related to unrecognized plan losses in the year these liabilities are paid. For further discussion and a sensitivity analysis on these assumptions, see "Employee Benefits" under Critical Accounting Policies and Estimates.

Regulation

FERC and State Regulation — The FERC and various state and local regulatory commissions regulate Xcel Energy Inc.'s utility subsidiaries and TransCo subsidiaries. Decisions by these regulators can significantly impact Xcel Energy's results of operations. Xcel Energy expects to periodically file for rate changes based on changing energy market and general economic conditions.

The electric and natural gas rates charged to customers of Xcel Energy Inc.'s utility subsidiaries are approved by the FERC or the regulatory commissions in the states in which they operate. The rates are designed to recover plant investment, operating costs and an allowed return on investment. Xcel Energy requests changes in rates for utility services through filings with the governing commissions. Changes in operating costs can affect Xcel Energy's financial results, depending on the timing of filing general rate cases and the implementation of final rates. In addition to changes in operating costs, other factors affecting rate filings are new investments, sales, conservation and DSM efforts, and the cost of capital. In addition, the regulatory commissions authorize the ROE, capital structure and depreciation rates in rate proceedings.

Wholesale Energy Market Regulation — Wholesale energy markets in the Midwest and South Central U.S. are operated by MISO and SPP, respectively, to centrally dispatch all regional electric generation and apply a regional transmission congestion management system. NSP-Minnesota and NSP-Wisconsin are members of MISO and SPS is a member of SPP. NSP-Minnesota, NSP-Wisconsin and SPS expect to recover energy charges through either base rates or various recovery mechanisms. See Note 12 to the consolidated financial statements for further discussion.

Capital Expenditure Regulation — Xcel Energy Inc.'s utility subsidiaries make substantial investments in plant additions to build and upgrade power plants, and expand and maintain the reliability of the energy transmission and distribution systems. In addition to filings for increases in base rates charged to customers to recover the costs associated with such investments, the CPUC, MPUC, SDPUC, NDPSC and PUCT in certain instances have approved proposals to recover, through a rate rider, costs to upgrade generation plants and lower emissions, increase transmission investment cost, and/or increase distribution investment cost, and increase purchased power capacity cost. These non-fuel rate riders are expected to provide cash flows to enable recovery of costs incurred on a more timely basis. For wholesale electric transmission and production services, Xcel Energy has, consistent with FERC policy, implemented formula rates for each of the utility subsidiaries that will provide annual rate changes as transmission or production investments increase in a manner similar to the retail rate riders. In November 2014, the FERC approved transmission formula rates for XETD and XEST, which would apply to electric transmission assets the TransCos may own. NSP-Minnesota and NSP-Wisconsin have no cost-based wholesale production customers and therefore have not implemented a production formula rate.

Environmental Matters

Environmental costs include accruals for nuclear plant decommissioning and payments for storage of spent nuclear fuel, disposal of hazardous materials and waste, remediation of contaminated sites, monitoring of discharges to the environment and compliance with laws and permits with respect to emissions. A trend of greater environmental awareness and increasingly stringent regulation may continue to cause higher operating expenses and capital expenditures for environmental compliance.

Costs charged to operating expenses for nuclear decommissioning and spent nuclear fuel disposal expenses, environmental monitoring and disposal of hazardous materials and waste were approximately:

- $292 million in 2014;
- $275 million in 2013; and
- $263 million in 2012.

Xcel Energy estimates an average annual expense of approximately $339 million from 2015 through 2019 for similar costs. The precise timing and amount of environmental costs, including those for site remediation and disposal of hazardous materials, are unknown. Additionally, the extent to which environmental costs will be included in and recovered through rates may fluctuate.

Capital expenditures for environmental improvements at regulated facilities were approximately:

- $373 million in 2014;
- $517 million in 2013; and
- $255 million in 2012.

See Item 7 — Capital Requirements for further discussion.

Xcel Energy's operations are subject to federal and state laws and regulations related to air emissions, water discharges and waste management from various sources. Such laws and regulations impose monitoring and reporting requirements and may require Xcel Energy to obtain pre-approval for the construction or modification of projects that increase air emissions, water discharges or land disposal of wastes, obtain and comply with permits that contain emission, discharge and operational limitations, or install or operate pollution control equipment at facilities. Xcel Energy will likely be required to incur capital expenditures in the future to comply with these requirements for remediation plans of MGP sites and various regulations for air emissions, water intake and discharge and waste disposal. Actual expenditures could vary from the estimates presented. The scope and timing of these expenditures cannot be determined until any new or revised regulations become final.

There are emission controls, known as BART, for industrial facilities releasing emissions that reduce visibility in certain national parks and wilderness areas. Xcel Energy generating facilities in Minnesota and Colorado are subject to BART requirements. Further, generating facilities throughout the Xcel Energy territory are subject to state and federal mercury reduction requirements. In addition, the EPA has proposed to require installation of dry scrubbers on Tolk Units 1 and 2 under a federal visibility plan for Texas.

See Note 13 to the consolidated financial statements for further discussion of Xcel Energy's environmental contingencies.

Inflation

Inflation at its current level is not expected to materially affect Xcel Energy's prices or returns to shareholders. However, potential future inflation could result from economic conditions or the economic and monetary policies of the U.S. Government and the Federal Reserve. This could lead to future price increases for materials and services required to deliver electric and natural gas services to customers. These potential cost increases could in turn lead to increased prices to customers. If current low oil prices lead to sustained deflation, that could also reduce general economic activity although it may lead to lower electric and natural gas prices to customers.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Preparation of the consolidated financial statements and related disclosures in compliance with GAAP requires the application of accounting rules and guidance, as well as the use of estimates. The application of these policies involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments could materially impact the consolidated financial statements and disclosures, based on varying assumptions. In addition, the financial and operating environment also may have a significant effect on the operation of the business and on the results reported. The following is a list of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and require management's most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions. Each critical accounting policy has been reviewed and discussed with the Audit Committee of Xcel Energy Inc.'s Board of Directors on a quarterly basis.

Regulatory Accounting

Xcel Energy Inc. is a holding company with rate-regulated subsidiaries that are subject to the accounting for Regulated Operations, which provides that rate-regulated entities account and report assets and liabilities consistent with the recovery of those incurred costs in rates and if the competitive environment makes it probable that such rates will be charged and collected. Xcel Energy's rates are derived through the ratemaking process, which results in the recording of regulatory assets and liabilities based on the probability of future cash flows. Regulatory assets generally represent incurred or accrued costs that have been deferred because they are probable of future recovery from customers. Regulatory liabilities generally represent amounts that are expected to be refunded to customers in future rates or amounts collected in current rates for future costs. In other businesses or industries, regulatory assets and regulatory liabilities would generally be charged to net income or OCI.

Each reporting period Xcel Energy assesses the probability of future recoveries and obligations associated with regulatory assets and liabilities. Factors such as the current regulatory environment, recently issued rate orders and historical precedents are considered. Decisions made by regulatory agencies can directly impact the amount and timing of cost recovery as well as the rate of return on invested capital and may materially impact Xcel Energy's results of operations, financial condition, or cash flows.

As of Dec. 31, 2014 and 2013, Xcel Energy has recorded regulatory assets of $3.2 billion and $2.9 billion and regulatory liabilities of $1.6 billion and $1.3 billion, respectively. Each subsidiary is subject to regulation that varies from jurisdiction to jurisdiction. If future recovery of costs, in any such jurisdiction, ceases to be probable, Xcel Energy would be required to charge these assets to current net income or OCI. There are no current or expected proposals or changes in the regulatory environment that impact the probability of future recovery of these assets. See Note 15 to the consolidated financial statements for further discussion of regulatory assets and liabilities and Note 12 to the consolidated financial statements for further discussion of rate matters.

Income Tax Accruals

Judgment, uncertainty, and estimates are a significant aspect of the income tax accrual process that accounts for the effects of current and deferred income taxes. Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals require that judgment and estimates be made in the accrual process and in the calculation of the ETR. Changes in tax laws and rates may affect recorded deferred tax assets and liabilities and our ETR in the future. There exists the potential for federal tax reform that may significantly change the tax rules applicable to Xcel Energy. At this time, due to the inherent uncertainty of future legislation, any potential resulting impact cannot be reasonably estimated.

ETRs are also highly impacted by assumptions. ETR calculations are revised every quarter based on best available year-end tax assumptions (income levels, deductions, credits, etc.); adjusted in the following year after returns are filed, with the tax accrual estimates being trued-up to the actual amounts claimed on the tax returns; and further adjusted after examinations by taxing authorities have been completed.

In accordance with the interim period reporting guidance, income tax expense for the first three quarters in a year is based on the forecasted ETR. The forecasted ETR reflects a number of estimates including forecasted annual income, permanent tax adjustments and tax credits.

Accounting for income taxes also requires that only tax benefits that meet the more likely than not recognition threshold can be recognized or continue to be recognized. The change in the unrecognized tax benefits needs to be reasonably estimated based on evaluation of the nature of uncertainty, the nature of event that could cause the change and an estimated range of reasonably possible changes. Management will use prudent business judgment to derecognize appropriate amounts of tax benefits at any period end, and as new developments occur. Unrecognized tax benefits can be recognized as issues are favorably resolved and loss exposures decline.

We may adjust our unrecognized tax benefits and interest accruals to the updated estimates as disputes with the IRS and state tax authorities are resolved. These adjustments may increase or decrease earnings. See Note 6 to the consolidated financial statements for further discussion.

Employee Benefits

Xcel Energy's pension costs are based on an actuarial calculation that includes a number of key assumptions, most notably the annual return level that pension and postretirement health care investment assets are expected to earn in the future and the interest rate used to discount future pension benefit payments to a present value obligation. In addition, the pension cost calculation uses an asset-smoothing methodology to reduce the volatility of varying investment performance over time. See Note 9 to the consolidated financial statements for further discussion on the rate of return and discount rate used in the calculation of pension costs and obligations.

Pension costs are expected to increase in 2015 and decline in the following few years. Funding requirements are expected to decrease in 2015 and then be flat in the following years. While investment returns exceeded the assumed levels in 2012 and again in 2014, investment returns were slightly below the assumed levels in 2013. The pension cost calculation uses a market-related valuation of pension assets. Xcel Energy uses a calculated value method to determine the market-related value of the plan assets. The market-related value is determined by adjusting the fair market value of assets at the beginning of the year to reflect the investment gains and losses (the difference between the actual investment return and the expected investment return on the market-related value) during each of the previous five years at the rate of 20 percent per year. As these differences between the actual investment returns and the expected investment returns are incorporated into the market-related value, the differences are recognized in pension cost over the expected average remaining years of service for active employees which was approximately 11 years in 2014.

Based on current assumptions and the recognition of past investment gains and losses, Xcel Energy currently projects the pension costs recognized for financial reporting purposes will be $140.4 million in 2015 and $129.6 million in 2016, while the actual pension costs were $126.5 million in 2014 and $151.8 million in 2013. The expected increase in the 2015 cost is due primarily to the impact of a potential settlement in the most recent Colorado electric rate case, updating the mortality tables and a decrease in the discount rate which were offset by the reduced amortization of prior service costs and other historic loss amounts, including the 2008 market loss. Further, future year costs are expected to decrease primarily as a result of reductions in loss amortizations and an increase in expected return on assets as a result of increases in assets via planned contributions and the subsequent expected return of current assets.

In 2014, the Society of Actuaries published a new mortality table and projection scale that increased the overall life expectancy of males and females. Xcel Energy has reviewed its own population through a credibility analysis and adopted the RP 2014 table with modifications based on our population and specific experience.

At Dec. 31, 2014, Xcel Energy set the rate of return on assets used to measure pension costs at 7.09 percent, which is a four basis point increase from Dec. 31, 2013. The rate of return used to measure postretirement health care costs is 5.80 percent at Dec. 31, 2014 and is a 137 basis point decrease from Dec. 31, 2013. Xcel Energy's ongoing investment strategy is based on plan-specific investment recommendations that seek to minimize potential investment and interest rate risk as a plan's funded status increases over time. The investment recommendations result in a greater percentage of long-duration fixed income securities being allocated to specific plans having relatively higher funded status ratios and a greater percentage of growth assets being allocated to plans having relatively lower funded status ratios.

Xcel Energy set the discount rates used to value the Dec. 31, 2014 pension and postretirement health care obligations at 4.11 percent and 4.08 percent, which represent a 64 basis point and 74 basis point decrease from Dec. 31, 2013, respectively. Xcel Energy uses a bond matching study as its primary basis for determining the discount rate used to value pension and postretirement health care obligations. The bond matching study utilizes a portfolio of high grade (Aa or higher) bonds that matches the expected cash flows of Xcel Energy's benefit plans in amount and duration. The effective yield on this cash flow matched bond portfolio determines the discount rate for the individual plans. The bond matching study is validated for reasonableness against the Citigroup Pension Liability Discount Curve and the Citigroup Above Median Curve. At Dec. 31, 2014, these reference points supported the selected rate. In addition to these reference points, Xcel Energy also reviews general actuarial survey data to assess the reasonableness of the discount rate selected.

The following are the pension funding contributions across all four of Xcel Energy's pension plans, both voluntary and required, for 2012 through 2015:

- $90.0 million in January 2015;
- $130.6 million in 2014;
- $192.4 million in 2013; and
- $198.1 million in 2012.

For future years, we anticipate contributions will be made as necessary. These contributions are summarized in Note 9 to the consolidated financial statements. Future year amounts are estimates and may change based on actual market performance, changes in interest rates and any changes in governmental regulations. Therefore, additional contributions could be required in the future.

If Xcel Energy were to use alternative assumptions at Dec. 31, 2014, a one-percent change would result in the following impact on 2015 pension costs:

(Millions of Dollars)	Pension Costs +1%	Pension Costs -1%
Rate of return	$ (20.6)	$ 20.6
Discount rate [a]	(10.6)	13.4

[a] These costs include the effects of regulation.

Effective Jan. 1, 2015, the initial medical trend assumption was decreased from 7.00 percent to 6.50 percent. The ultimate trend assumption remained at 4.5 percent. The period until the ultimate rate is reached is four years. Xcel Energy bases its medical trend assumption on the long-term cost inflation expected in the health care market, considering the levels projected and recommended by industry experts, as well as recent actual medical cost experienced by Xcel Energy's retiree medical plan.

- Xcel Energy contributed $17.1 million, $17.6 million and $47.1 million during 2014, 2013 and 2012, respectively, to the postretirement health care plans.
- Xcel Energy expects to contribute approximately $12.8 million during 2015.

Xcel Energy recovers employee benefits costs in its regulated utility operations consistent with accounting guidance with the exception of the areas noted below.

- NSP-Minnesota recognizes pension expense in all regulatory jurisdictions based on expense as calculated using the aggregate normal cost actuarial method. Differences between aggregate normal cost and expense as calculated by pension accounting standards are deferred as a regulatory liability.
- Colorado, Texas, New Mexico and FERC jurisdictions allow the recovery of other postretirement benefit costs only to the extent that recognized expense is matched by cash contributions to an irrevocable trust. Xcel Energy has consistently funded at a level to allow full recovery of costs in these jurisdictions.
- PSCo and SPS recognize pension expense in all regulatory jurisdictions based on expense consistent with accounting guidance. The Colorado electric retail and Texas jurisdictions record the difference between annual recognized pension expense and the annual amount of pension expense approved in their last respective general rate case as a deferral to a regulatory asset.
- Beginning in 2015, the Colorado electric retail jurisdiction expects to recognize additional expense associated with a pending order to accelerate amortization of the qualified prepaid pension asset. A regulatory liability would be recorded to account for any resulting regulatory obligation.

See Note 9 to the consolidated financial statements for further discussion.

Nuclear Decommissioning

Xcel Energy recognizes liabilities for the expected cost of retiring tangible long-lived assets for which a legal obligation exists. These AROs are recognized at fair value as incurred and are capitalized as part of the cost of the related long-lived assets. In the absence of quoted market prices, Xcel Energy estimates the fair value of its AROs using present value techniques, in which it makes various assumptions including estimates of the amounts and timing of future cash flows associated with retirement activities, credit-adjusted risk free rates and cost escalation rates. When Xcel Energy revises any assumptions used to estimate AROs, it adjusts the carrying amount of both the ARO liability and the related long-lived asset. Xcel Energy accretes ARO liabilities to reflect the passage of time using the interest method.

A significant portion of Xcel Energy's AROs relates to the future decommissioning of NSP-Minnesota's nuclear facilities. The total obligation for nuclear decommissioning is expected to be funded 100 percent by the external decommissioning trust fund. The difference between regulatory funding (including depreciation expense less returns from the external trust fund) and expense recognized under current accounting guidance is deferred as a regulatory asset. The amounts recorded for AROs related to future nuclear decommissioning were $2,038 million and $1,628 million as of Dec. 31, 2014 and 2013, respectively. Based on their significance, the following discussion relates specifically to the AROs associated with nuclear decommissioning.

NSP-Minnesota obtains periodic cost studies in order to estimate the cost and timing of planned nuclear decommissioning activities. These independent cost studies are based on relevant information available at the time performed. Estimates of future cash flows for extended periods of time are by nature highly uncertain and may vary significantly from actual results. NSP-Minnesota is required to file a nuclear decommissioning study every three years. In December 2014, NSP-Minnesota submitted this filing to the MPUC, which covered all expenses over the decommissioning period of the nuclear plants, including decontamination and removal of radioactive material. A decision on the filing is expected in late 2015 or early 2016.

The following key assumptions have a significant effect on the estimated nuclear obligation:

- Timing — Decommissioning cost estimates are impacted by each facility's retirement date and the expected timing of the actual decommissioning activities. Currently, the estimated retirement dates coincide with each unit's operating license with the NRC (i.e., 2030 for Monticello and 2033 and 2034 for PI's Unit 1 and 2, respectively). The estimated timing of the decommissioning activities is based upon the DECON method, which is required by the MPUC. By utilizing this method, which assumes prompt removal and dismantlement, these activities are expected to begin at the end of the license date and be completed for both facilities by 2091.

- Technology and Regulation — There is limited experience with actual decommissioning of large nuclear facilities. Changes in technology and experience as well as changes in regulations regarding nuclear decommissioning could cause cost estimates to change significantly. NSP-Minnesota's 2014 nuclear decommissioning filing assumed current technology and regulations.

- Escalation Rates — Escalation rates represent projected cost increases over time due to both general inflation and increases in the cost of specific decommissioning activities. NSP-Minnesota used an escalation rate of 4.36 percent in calculating the AROs related to nuclear decommissioning for the remaining operational period through the radiological decommissioning period. An escalation rate of 3.36 percent was utilized for the period of operating costs related to interim dry cask storage of spent nuclear fuel and site restoration.

- Discount Rates — Changes in timing or estimated expected cash flows that result in upward revisions to the ARO are calculated using the then-current credit-adjusted risk-free interest rate. The credit-adjusted risk-free rate in effect when the change occurs is used to discount the revised estimate of the incremental expected cash flows of the retirement activity. If the change in timing or estimated expected cash flows results in a downward revision of the ARO, the undiscounted revised estimate of expected cash flows is discounted using the credit-adjusted risk-free rate in effect at the date of initial measurement and recognition of the original ARO. Discount rates ranging from approximately four and seven percent have been used to calculate the net present value of the expected future cash flows over time.

Significant uncertainties exist in estimating the future cost of nuclear decommissioning including the method to be utilized, the ultimate costs to decommission, and the planned method of disposing spent fuel. If different cost estimates, life assumptions or cost escalation rates were utilized, the AROs could change materially. However, changes in estimates have minimal impact on results of operations as NSP-Minnesota expects to continue to recover all costs in future rates.

Xcel Energy continually makes judgments and estimates related to these critical accounting policy areas, based on an evaluation of the varying assumptions and uncertainties for each area. The information and assumptions underlying many of these judgments and estimates will be affected by events beyond the control of Xcel Energy, or otherwise change over time. This may require adjustments to recorded results to better reflect the events and updated information that becomes available. The accompanying financial statements reflect management's best estimates and judgments of the impact of these factors as of Dec. 31, 2014.

Derivatives, Risk Management and Market Risk

Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks in the normal course of business. Market risk is the potential loss that may occur as a result of adverse changes in the market or fair value of a particular instrument or commodity. All financial and commodity-related instruments, including derivatives, are subject to market risk. See Note 11 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of adverse changes in price for energy and energy-related products, which is partially mitigated by the use of commodity derivatives. In addition to ongoing monitoring and maintaining credit policies intended to minimize overall credit risk, when necessary, management takes steps to mitigate changes in credit and concentration risks associated with its derivatives and other contracts, including parental guarantees and requests of collateral. While Xcel Energy expects that the counterparties will perform under the contracts underlying its derivatives, the contracts expose Xcel Energy to some credit and non-performance risk.

Though no material non-performance risk currently exists with the counterparties to Xcel Energy's commodity derivative contracts, distress in the financial markets may in the future impact that risk to the extent it impacts those counterparties. Distress in the financial markets may also impact the fair value of the securities in the nuclear decommissioning fund and master pension trust, as well as Xcel Energy's ability to earn a return on short-term investments of excess cash.

Commodity Price Risk — Xcel Energy Inc.'s utility subsidiaries are exposed to commodity price risk in their electric and natural gas operations. Commodity price risk is managed by entering into long- and short-term physical purchase and sales contracts for electric capacity, energy and energy-related products and for various fuels used in generation and distribution activities. Commodity price risk is also managed through the use of financial derivative instruments. Xcel Energy's risk management policy allows it to manage commodity price risk within each rate-regulated operation to the extent such exposure exists.

Wholesale and Commodity Trading Risk — Xcel Energy Inc.'s utility subsidiaries conduct various wholesale and commodity trading activities, including the purchase and sale of electric capacity, energy and energy-related instruments. Xcel Energy's risk management policy allows management to conduct these activities within guidelines and limitations as approved by its risk management committee, which is made up of management personnel not directly involved in the activities governed by this policy.

At Dec. 31, 2014, the fair values by source for net commodity trading contract assets were as follows:

		Futures / Forwards				
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures / Forwards Fair Value
NSP-Minnesota	1	$ 6,359	$ 8,238	$ 1,401	$ 1,088	$ 17,086
	2	4,400	—	—	—	4,400
		$ 10,759	$ 8,238	$ 1,401	$ 1,088	$ 21,486

		Options				
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$ 325	$ —	$ —	$ —	$ 325

1 — Prices actively quoted or based on actively quoted prices.
2 — Prices based on models and other valuation methods.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms for the years ended Dec. 31, were as follows:

(Thousands of Dollars)	2014	2013
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 30,514	$ 28,314
Contracts realized or settled during the period	(12,698)	(6,665)
Commodity trading contract additions and changes during the period	3,995	8,865
Fair value of commodity trading net contract assets outstanding at Dec. 31	$ 21,811	$ 30,514

At Dec. 31, 2014, a 10 percent increase in market prices for commodity trading contracts would increase pretax income by approximately $0.9 million, whereas a 10 percent decrease would decrease pretax income by approximately $0.9 million. At Dec. 31, 2013, a 10 percent increase in market prices for commodity trading contracts would decrease pretax income by approximately $0.6 million, whereas a 10 percent decrease would increase pretax income by approximately $0.6 million.

Xcel Energy Inc.'s utility subsidiaries' wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, including transactions that are not recorded at fair value, using an industry standard methodology known as Value at Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time under normal market conditions.

The VaRs for the NSP-Minnesota and PSCo commodity trading operations, calculated on a consolidated basis using a Monte Carlo simulation with a 95 percent confidence level and a one-day holding period, were as follows:

(Millions of Dollars)	Year Ended Dec. 31	VaR Limit	Average	High	Low
2014	$ 0.57	$ 3.00	$ 0.61	$ 4.06	$ 0.13
2013	0.29	3.00	0.41	1.65	<0.01

Nuclear Fuel Supply — NSP-Minnesota is scheduled to take delivery of approximately 13 percent of its 2015 enriched nuclear material requirements from sources that could be impacted by events in Ukraine and sanctions against Russia. In 2014, NSP-Minnesota arranged for and took delivery of material from alternate sources that were not impacted by these world events. These alternate sources are expected to provide the flexibility to manage NSP-Minnesota's nuclear fuel supply to ensure that plant availability and reliability will not be negatively impacted in the near-term. Long-term, through 2024, NSP-Minnesota is scheduled to take delivery of approximately 34 percent of its average enriched nuclear material requirements from sources that could be impacted by events in Ukraine and extended sanctions against Russia. NSP-Minnesota is closely following the progression of these events and will periodically assess if further actions are required to assure a secure supply of enriched nuclear material beyond 2015.

Interest Rate Risk — Xcel Energy is subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy's risk management policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Dec. 31, 2014 and 2013, a 100 basis point change in the benchmark rate on Xcel Energy's variable rate debt would impact annual pretax interest expense by approximately $10.4 million and $8.3 million, respectively. See Note 11 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

NSP-Minnesota also maintains a nuclear decommissioning fund, as required by the NRC. The nuclear decommissioning fund is subject to interest rate risk and equity price risk. At Dec. 31, 2014, the fund was invested in a diversified portfolio of cash equivalents, debt securities, equity securities, and other investments. These investments may be used only for activities related to nuclear decommissioning. Given the purpose and legal restrictions on the use of nuclear decommissioning fund assets, realized and unrealized gains on fund investments over the life of the fund are deferred as an offset of NSP-Minnesota's regulatory asset for nuclear decommissioning costs. Consequently, any realized and unrealized gains and losses on securities in the nuclear decommissioning fund, including any other-than-temporary impairments, are deferred as a component of the regulatory asset for nuclear decommissioning. Since the accounting for nuclear decommissioning recognizes that costs are recovered through rates, fluctuations in equity prices or interest rates do not have a direct impact on earnings.

Credit Risk — Xcel Energy Inc. and its subsidiaries are also exposed to credit risk. Credit risk relates to the risk of loss resulting from counterparties' nonperformance on their contractual obligations. Xcel Energy Inc. and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

At Dec. 31, 2014, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $12.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2.7 million. At Dec. 31, 2013, a 10 percent increase in commodity prices would have resulted in an increase in credit exposure of $15.2 million, while a decrease in prices of 10 percent would have resulted in an increase in credit exposure of $2.6 million.

Xcel Energy Inc. and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. Credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided. Distress in the financial markets could increase Xcel Energy's credit risk.

Fair Value Measurements

Xcel Energy follows accounting and disclosure guidance on fair value measurements that contains a hierarchy for inputs used in measuring fair value and requires disclosure of the observability of the inputs used in these measurements. See Note 11 to the consolidated financial statements for further discussion of the fair value hierarchy and the amounts of assets and liabilities measured at fair value that have been assigned to Level 3.

Commodity Derivatives — Xcel Energy continuously monitors the creditworthiness of the counterparties to its commodity derivative contracts and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment and the typically short duration of these contracts, the impact of discounting commodity derivative assets for counterparty credit risk was not material to the fair value of commodity derivative assets at Dec. 31, 2014. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues. Credit risk adjustments for other commodity derivative instruments are deferred as OCI or regulatory assets and liabilities. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy also assesses the impact of its own credit risk when determining the fair value of commodity derivative liabilities. The impact of discounting commodity derivative liabilities for credit risk was immaterial to the fair value of commodity derivative liabilities at Dec. 31, 2014.

Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs, as well as forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 3.7 percent and 41.0 percent of gross assets and liabilities, respectively, measured at fair value at Dec. 31, 2014.

Determining the fair value of FTRs requires numerous management forecasts that vary in observability, including various forward commodity prices, retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management's forecasts for several of these inputs, these instruments have been assigned a Level 3. Level 3 commodity derivatives assets and liabilities included $67.0 million and $10.9 million of estimated fair values, respectively, for FTRs held at Dec. 31, 2014.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective price and volatility forecasts which extend to periods beyond those readily observable on active exchanges or quoted by brokers. When less observable forward price and volatility forecasts are significant to determining the value of commodity forwards and options, these instruments are assigned to Level 3. There were no Level 3 forwards or options held at Dec. 31, 2014.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of private equity investments and real estate investments. Based on an evaluation of NSP-Minnesota's ability to redeem private equity investments and real estate investment funds measured at net asset value, estimated fair values for these investments totaling $165.5 million in the nuclear decommissioning fund at Dec. 31, 2014 (approximately 9.2 percent of total assets measured at fair value) are assigned to Level 3. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a regulatory asset.

Liquidity and Capital Resources

Cash Flows

(Millions of Dollars)	2014	2013	2012
Net cash provided by operating activities	$ 2,648	$ 2,584	$ 2,005

Net cash provided by operating activities increased by $64 million for 2014 as compared to 2013. Additional net income, excluding amounts related to non-cash operating activities (e.g. depreciation and deferred tax expenses) and lower pension contributions in 2014 were offset by changes in working capital and other noncurrent assets and liabilities.

Net cash provided by operating activities increased by $579 million for 2013 as compared to 2012. The increase was primarily the result of higher net income, changes in working capital due to the timing of payments and receipts, net changes in regulatory assets and liabilities, and payments mainly related to interest rate swap settlements in 2012.

(Millions of Dollars)	2014	2013	2012
Net cash used in investing activities	$ (3,117)	$ (3,213)	$ (2,333)

Net cash used in investing activities decreased by $96 million for 2014 as compared to 2013. The decrease was primarily attributable to higher capital expenditures in 2013 associated with several major construction projects including the Monticello nuclear EPU and the PI steam generator replacement. The change in capital expenditures was partially offset by the impact of higher insurance proceeds related to Sherco Unit 3 and proceeds received from the sale of certain transmission assets to Sharyland in 2013.

Net cash used in investing activities increased by $880 million for 2013 as compared to 2012. The increase was primarily the result of higher capital expenditures for several major construction projects including the Monticello nuclear EPU project as well as the PI steam generator replacement and certain other transmission line projects. Other differences mainly related to changes in restricted cash.

(Millions of Dollars)	2014	2013	2012
Net cash provided by financing activities	$ 442	$ 654	$ 350

Net cash provided by financing activities decreased by $212 million for 2014 as compared to 2013. The decrease was primarily due to lower proceeds from long-term debt, less issuances of common stock and higher dividend payments, partially offset by higher proceeds from short-term debt and lower repayments of long-term debt.

Net cash provided by financing activities increased by $654 million for 2013 as compared to 2012. The increase was primarily due to the issuance of more common stock during 2013, lower repayments of previously existing long-term debt, which was partially offset by reductions in long-term and short-term borrowing.

See discussion of trends, commitments and uncertainties with the potential for future impact on cash flow and liquidity under Capital Sources.

Capital Requirements

Xcel Energy expects to meet future financing requirements by periodically issuing short-term debt, long-term debt, common stock, hybrid and other securities to maintain desired capitalization ratios.

Capital Expenditures — The current estimated capital expenditure programs of Xcel Energy Inc. and its subsidiaries for the years 2015 through 2019 are shown in the table below.

	Actual	Forecast					
(Millions of Dollars)	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
By Subsidiary							
NSP-Minnesota	$ 1,159	$ 1,625	$ 990	$ 975	$ 845	$ 950	$ 5,385
PSCo	1,064	950	820	815	885	1,010	4,480
SPS	542	570	710	735	595	565	3,175
NSP-Wisconsin	290	230	260	300	325	325	1,440
Total capital expenditures	$ 3,055	$ 3,375	$ 2,780	$ 2,825	$ 2,650	$ 2,850	$ 14,480

By Function	2014	2015	2016	2017	2018	2019	2015 - 2019 Total
Electric transmission	$ 972	$ 875	$ 780	$ 905	$ 975	$ 1,000	$ 4,535
Electric generation	710	1,190	630	620	415	450	3,305
Electric distribution	545	605	630	640	650	680	3,205
Natural gas	525	370	370	305	355	380	1,780
Nuclear fuel	154	90	120	120	65	150	545
Other	149	245	250	235	190	190	1,110
Total capital expenditures	$ 3,055	$ 3,375	$ 2,780	$ 2,825	$ 2,650	$ 2,850	$ 14,480

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility capital expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, regulatory decisions, legislative initiatives, reserve margin requirements, the availability of purchased power, alternative plans for meeting long-term energy needs, compliance with environmental requirements, RPS and merger, acquisition and divestiture opportunities. The table above does not include potential expenditures of Xcel Energy's TransCos.

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

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

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

Contractual Obligations and Other Commitments — In addition to its capital expenditure programs, Xcel Energy has contractual obligations and other commitments that will need to be funded in the future. The following is a summarized table of contractual obligations and other commercial commitments at Dec. 31, 2014. See the statements of capitalization and additional discussion in Notes 4 and 13 to the consolidated financial statements.

	Payments Due by Period				
(Thousands of Dollars)	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	After 5 Years
Long-term debt, principal and interest payments [a]	$ 20,295,497	$ 788,787	$ 2,069,075	$ 2,483,533	$ 14,954,102
Capital lease obligations	352,185	17,787	32,143	29,154	273,101
Operating leases [b][c]	3,103,660	254,550	467,423	463,693	1,917,994
Unconditional purchase obligations [d]	10,101,197	2,023,394	2,555,760	1,406,598	4,115,445
Other long-term obligations, including current portion [e]	200,289	52,207	83,775	64,307	—
Payments to vendors in process	35,151	35,151	—	—	—
Short-term debt	1,019,500	1,019,500	—	—	—
Total contractual cash obligations [f][g][h]	$ 35,107,479	$ 4,191,376	$ 5,208,176	$ 4,447,285	$ 21,260,642

(a) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at Dec. 31, 2014, and outstanding principal for each investment with the terms ending at each instrument's maturity.

(b) Under some leases, Xcel Energy would have to sell or purchase the property that it leases if it chose to terminate before the scheduled lease expiration date. Most of Xcel Energy's railcar, vehicle and equipment and aircraft leases have these terms. At Dec. 31, 2014, the amount that Xcel Energy would have to pay if it chose to terminate these leases was approximately $62.2 million. In addition, at the end of the equipment lease terms, each lease must be extended, equipment purchased for the greater of the fair value or unamortized value of equipment sold to a third party with Xcel Energy making up any deficiency between the sales price and the unamortized value.

(c) Included in operating lease payments are $228.3 million, $425.4 million, $424.6 million and $1.8 billion, for the less than 1 year, 1-3 years, 3-5 years and after 5 years categories, respectively, pertaining to PPAs that were accounted for as operating leases.

(d) Xcel Energy Inc. and its subsidiaries have contracts providing for the purchase and delivery of a significant portion of its current coal, nuclear fuel and natural gas requirements. Additionally, the utility subsidiaries of Xcel Energy Inc. have entered into agreements with utilities and other energy suppliers for purchased power to meet system load and energy requirements, replace generation from company-owned units under maintenance and during outages, and meet operating reserve obligations. Certain contractual purchase obligations are adjusted on indices. The effects of price changes are mitigated through cost of energy adjustment mechanisms.

(e) Other long-term obligations relate primarily to amounts associated with technology agreements as well as uncertain tax positions.

(f) Xcel Energy also has outstanding authority under O&M contracts to purchase up to approximately $3.6 billion of goods and services through the year 2050, in addition to the amounts disclosed in this table.

(g) In January 2015, contributions of $90.0 million were made across four of Xcel Energy's pension plans. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

(h) Xcel Energy expects to contribute approximately $12.8 million to the postretirement health care plans during 2015. Obligations of this type are dependent on several factors, including management discretion, and therefore, they are not included in the table.

Common Stock Dividends — Future dividend levels will be dependent on Xcel Energy's results of operations, financial position, cash flows, reinvestment opportunities and other factors, and will be evaluated by the Xcel Energy Inc. Board of Directors. Xcel Energy's financial objectives include: growing annual ongoing EPS four percent to six percent, growing the annual dividend five percent to seven percent and targeting a dividend payout ratio of 60 percent to 70 percent of annual ongoing EPS. On Feb. 18, 2015, Xcel Energy announced a quarterly dividend of $0.32 per share, which represented an increase of 6.7 percent. Xcel Energy's dividend policy balances:

- Projected cash generation;
- Projected capital investment;
- A reasonable rate of return on shareholder investment; and
- The impact on Xcel Energy's capital structure and credit ratings.

In addition, there are certain statutory limitations that could affect dividend levels. Federal law places certain limits on the ability of public utilities within a holding company system to declare dividends.

Specifically, under the Federal Power Act, a public utility may not pay dividends from any funds properly included in a capital account. The utility subsidiaries' dividends may be limited directly or indirectly by state regulatory commissions or bond indenture covenants. See Note 4 to the consolidated financial statements for further discussion of restrictions on dividend payments.

Regulation of Derivatives — In July 2010, financial reform legislation was passed that provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the CFTC and the SEC with expanded regulatory authority over derivative and swap transactions. Regulations effected under this legislation could preclude or impede some types of over-the-counter energy commodity transactions and/or require clearing through regulated central counterparties, which could negatively impact the market for these transactions or result in extensive margin and fee requirements.

As a result of this legislation, there will be material increased reporting requirements for certain volumes of derivative and swap activity. In April 2012, the CFTC ruled that swap dealing activity conducted by entities for the preceding 12 months under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the general de minimis threshold and will not subject an entity to registering as a swap dealer. An entity may deal in utility operations-related swaps and not be required to register as a swap dealer provided that the aggregate gross notional amount of swap dealing activity (including utility operations-related swaps) does not exceed the general de minimis threshold and provided that the entity has not exceeded the special entity de minimis threshold (excluding utility operations-related swaps) of $25 million for the preceding 12 months. Xcel Energy's current and projected swap activity is well below these de minimis thresholds. The bill also contains provisions that should exempt certain derivatives end users from much of the clearing and margin requirements. Xcel Energy does not expect to be materially impacted by the margining provisions. Xcel Energy is currently meeting all other reporting requirements.

SPP FTR Margining Requirements — The SPP conducted its first annual FTR auction in the spring of 2014 associated with the implementation of the SPP IM. The process for transmission owners involves the receipt of Auction Revenue Rights (ARRs) and, if elected by the transmission owner, conversion of those ARRs to firm FTRs. SPP requires that the transmission owner post collateral for the conversion of ARRs to FTRs. At Dec. 31, 2014, SPS had a $30 million letter of credit posted with SPP, which was a reduction from the initial requirement of $41 million.

Pension Fund — Xcel Energy's pension assets are invested in a diversified portfolio of domestic and international equity securities, short-term to long-duration fixed income and interest rate swap securities, and alternative investments, including private equity, real estate, hedge funds and commodity investments.

The funded status and pension assumptions are summarized in the following tables:

(Millions of Dollars)	Dec. 31, 2014	Dec. 31, 2013
Fair value of pension assets	$ 3,084	$ 3,010
Projected pension obligation [a]	3,747	3,441
Funded status	$ (663)	$ (431)

[a] Excludes nonqualified plan of $47 million and $37 million at Dec. 31, 2014 and 2013, respectively.

Pension Assumptions	2014	2013
Discount rate	4.11%	4.75%
Expected long-term rate of return	7.09	7.05

Capital Sources

Short-Term Funding Sources — Xcel Energy uses a number of sources to fulfill short-term funding needs, including operating cash flow, notes payable, commercial paper and bank lines of credit. The amount and timing of short-term funding needs depend in large part on financing needs for construction expenditures, working capital and dividend payments.

Short-Term Investments — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS maintain cash operating and short-term investment accounts. At Dec. 31, 2014 and 2013, there was $3.3 million and $21.7 million of cash held in these accounts, respectively.

Commercial Paper — Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS each have individual commercial paper programs. The authorized levels for these commercial paper programs are:

- $1 billion for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $400 million for SPS; and
- $150 million for NSP-Wisconsin.

Commercial paper outstanding for Xcel Energy was as follows:

(Amounts in Millions, Except Interest Rates)	Three Months Ended Dec. 31, 2014
Borrowing limit	$ 2,750
Amount outstanding at period end	1,020
Average amount outstanding	802
Maximum amount outstanding	1,021
Weighted average interest rate, computed on a daily basis	0.36%
Weighted average interest rate at end of period	0.56

(Amounts in Millions, Except Interest Rates)	Year Ended Dec. 31, 2014	Year Ended Dec. 31, 2013	Year Ended Dec. 31, 2012
Borrowing limit	$ 2,750	$ 2,450	$ 2,450
Amount outstanding at period end	1,020	759	602
Average amount outstanding	841	481	403
Maximum amount outstanding	1,200	1,160	634
Weighted average interest rate, computed on a daily basis	0.33%	0.31%	0.35%
Weighted average interest rate at end of period	0.56	0.25	0.36

Credit Facilities — In October 2014, Xcel Energy Inc., NSP-Minnesota, NSP-Wisconsin, PSCo and SPS entered into amended five-year credit agreements with a syndicate of banks, replacing their previous five-year credit agreements. The total size of the credit facilities is $2.75 billion and each credit facility terminates in October 2019.

NSP-Minnesota, PSCo, SPS and Xcel Energy Inc. each have the right to request an extension of the revolving termination date for two additional one-year periods. NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period. All extension requests are subject to majority bank group approval.

As of Feb. 18, 2015, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Facility [a]	Drawn [b]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,000.0	$ 505.0	$ 495.0	$ 0.2	$ 495.2
PSCo	700.0	243.4	456.6	0.4	457.0
NSP-Minnesota	500.0	139.1	360.9	1.0	361.9
SPS	400.0	138.0	262.0	1.0	263.0
NSP-Wisconsin	150.0	51.0	99.0	0.9	99.9
Total	$ 2,750.0	$ 1,076.5	$ 1,673.5	$ 3.5	$ 1,677.0

(a) These credit facilities have been amended to extend the maturity to October 2019.

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

Money Pool — Xcel Energy received FERC approval to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. The utility money pool allows for short-term investments in and borrowings between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated in consolidation.

NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions. NSP-Wisconsin does not participate in the money pool.

Registration Statements — Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of one billion shares of $2.50 par value common stock. As of Dec. 31, 2014 and 2013, Xcel Energy Inc. had approximately 506 million shares and 498 million shares of common stock outstanding, respectively. In addition, Xcel Energy Inc.'s Articles of Incorporation authorize the issuance of seven million shares of $100 par value preferred stock. Xcel Energy Inc. had no shares of preferred stock outstanding on Dec. 31, 2014 and 2013.

Xcel Energy Inc. and its subsidiaries have the following registration statements on file with the SEC, pursuant to which they may sell, from time to time, securities:

- Xcel Energy Inc. has an effective automatic shelf registration statement filed in August 2012, which does not contain a limit on issuance capacity. However, Xcel Energy Inc.'s ability to issue securities is limited by authority granted by the Board of Directors, which currently authorizes the issuance of up to an additional $900 million of debt and common equity securities.
- NSP-Minnesota has an automatic shelf registration statement filed in December 2013, which does not contain a limit on issuance capacity. However, NSP-Minnesota's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to an additional $750 million of debt securities.
- NSP-Wisconsin has $100 million of debt securities remaining under its currently effective shelf registration statement, which was filed in December 2013.
- PSCo has an automatic shelf registration statement filed in October 2013, which does not contain a limit on issuance capacity. However, PSCo's ability to issue securities is limited by authority granted by its Board of Directors, which currently authorizes the issuance of up to an additional $700 million of debt securities.
- SPS has $150 million of debt securities remaining under its currently effective shelf registration statement, which was filed in April 2013. SPS intends to register additional debt securities in 2015.

Long-Term Borrowings and Other Financing Instruments — See the consolidated statements of capitalization and a discussion of the long-term borrowings in Note 4 to the consolidated financial statements.

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

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

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

Financing Plans — 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.

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

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

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

Off-Balance-Sheet Arrangements

Xcel Energy does not have any off-balance-sheet arrangements, other than those currently disclosed, that have or are reasonably likely to have a current or future effect on financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Earnings Guidance

Xcel Energy's 2015 ongoing earnings guidance is $2.00 to $2.15 per share. Key assumptions related to 2015 earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- If the MPUC orders a disallowance in the Monticello prudence review, Xcel Energy would exclude the associated charge from ongoing earnings.
- Normal weather patterns are experienced for the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 1.0 percent.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2.0 percent.
- Capital rider revenue is projected to increase by $160 million to $170 million over 2014 levels. The projected capital rider revenue reflects the transfer of the CACJA project from base rates to the rider per the settlement in the Colorado electric rate case. The settlement is pending CPUC approval.
- The change in O&M expenses is projected to be within a range of 0 percent to 2 percent from 2014 levels.
- Depreciation expense is projected to increase $160 million to $180 million over 2014 levels, reflecting the originally proposed acceleration of the amortization of the excess depreciation reserve as part of NSP-Minnesota's moderation plan in the Minnesota electric rate case.
- Property taxes are projected to increase approximately $60 million to $70 million over 2014 levels.
- Interest expense (net of AFUDC — debt) is projected to increase $40 million to $50 million over 2014 levels.
- AFUDC — equity is projected to decline approximately $35 million to $45 million from 2014 levels.
- The ETR is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 508 million shares.

Long-Term EPS and Dividend Growth Rate Objectives

Xcel Energy expects to deliver an attractive total return to our shareholders through a combination of earnings growth and dividend yield, based on the following long-term objectives:

- Deliver long-term annual EPS growth of 4 percent to 6 percent, based on weather-normalized, ongoing 2014 EPS of $2.00;
- Deliver annual dividend increases of 5 percent to 7 percent;
- Target a dividend payout ratio of 60 percent to 70 percent of annual ongoing EPS; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

Ongoing earnings is calculated using net income and adjusting for certain nonrecurring or infrequent items that are, in management's view, not reflective of ongoing operations.

Item 7A — Quantitative and Qualitative Disclosures About Market Risk

See Item 7, incorporated by reference.

Item 8 — Financial Statements and Supplementary Data

See Item 15-1 for an index of financial statements included herein.

See Note 18 to the consolidated financial statements for summarized quarterly financial data.

Management Report on Internal Controls Over Financial Reporting

The management of Xcel Energy Inc. is responsible for establishing and maintaining adequate internal control over financial reporting. Xcel Energy Inc.'s internal control system was designed to provide reasonable assurance to Xcel Energy Inc.'s management and board of directors regarding the preparation and fair presentation of published financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Xcel Energy Inc. management assessed the effectiveness of Xcel Energy Inc.'s internal control over financial reporting as of Dec. 31, 2014. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework (2013)*. Based on our assessment, we believe that, as of Dec. 31, 2014, Xcel Energy Inc.'s internal control over financial reporting is effective at the reasonable assurance level based on those criteria.

Xcel Energy Inc.'s independent registered public accounting firm has issued an audit report on the Xcel Energy Inc.'s internal control over financial reporting. Its report appears herein.

/s/ BEN FOWKE
Ben Fowke
Chairman, President and Chief Executive Officer
Feb. 20, 2015

/s/ TERESA S. MADDEN
Teresa S. Madden
Executive Vice President, Chief Financial Officer
Feb. 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.
Minneapolis, Minnesota

We have audited the accompanying consolidated balance sheets and statements of capitalization of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows, and common stockholders' equity for each of the three years in the period ended December 31, 2014. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Xcel Energy Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2015

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Xcel Energy Inc.
Minneapolis, Minnesota

We have audited the internal control over financial reporting of Xcel Energy Inc. and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Controls over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2014 of the Company and our report dated February 20, 2015 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 20, 2015