414 Nicollet Mall
Minneapolis, MN 55401

July 30, 2015

XCEL ENERGY
SECOND QUARTER 2015 EARNINGS REPORT

- GAAP (generally accepted accounting principles) and ongoing 2015 second quarter earnings per share were $0.39 compared with $0.39 per share in 2014.
- Xcel Energy reaffirms 2015 ongoing earnings guidance of $2.00 to $2.15 per share.

MINNEAPOLIS — Xcel Energy Inc. (NYSE: XEL) today reported 2015 second quarter GAAP and ongoing earnings of $197 million, or $0.39 per share, compared with $195 million, or $0.39 per share, in the same period in 2014.

Second quarter electric margin increased due to new rates and riders in various jurisdictions and a lower PSCo earnings test refund that was partially offset by weather-normalized sales decline and unfavorable weather, having an impact of $0.02. The increase in margin was offset by higher depreciation, lower allowance for funds used during construction, higher property taxes, operating and maintenance expenses and interest charges.

“Our financial results during the first half of the year were generally in line with our expectations and we continue to expect to deliver ongoing earnings within our 2015 ongoing earnings guidance of $2.00 to $2.15 per share, despite lower than anticipated sales, unfavorable weather and adjustments to our rate request in Minnesota,” said Chairman, President and Chief Executive Officer Ben Fowke.

“Over the last several quarters, we laid out plans to reduce the ROE gap at our utilities and we are especially pleased with our progress this quarter. Recently signed legislation in Minnesota and Texas supplements our regulatory compact with new tools, supports our efforts as we continue to strengthen the system for our customers and improves our visibility on meeting our long term earnings growth objectives.”

“Importantly, the new legislation brings a longer-term focus to regulation in Minnesota, similar to what we have already accomplished in Colorado and North Dakota. Aligning the policies, business plans and rates in each of the states we serve is an important part of our strategy, and we took a big step forward this quarter.”

“In other good news, our Monticello nuclear plant has received final NRC approval and is operating at full capacity. In Colorado, our Cherokee combine-cycle plant completed its first-fire. The project is on budget and on time.”

Earnings Adjusted for Certain Items (Ongoing Earnings)

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

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2015**	**2014**	**2015**	**2014**
Ongoing diluted EPS	$ 0.39	$ 0.39	$ 0.85	$ 0.91
Loss on Monticello life cycle management/extended power uprate project [(a)]	—	—	(0.16)	—
GAAP diluted EPS	$ 0.39	$ 0.39	$ 0.69	$ 0.91

(a) See Note 7.

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

US Dial-In:	(877) 723-9520
International Dial-In:	(719) 325-4744
Conference ID:	5079681

The conference call also will be simultaneously broadcast and archived on Xcel Energy's website at www.xcelenergy.com. To access the presentation, click on Investor Relations. If you are unable to participate in the live event, the call will be available for replay from 12:00 p.m. CDT on July 30 through 10:59 p.m. CDT on Aug. 1.

Replay Numbers	
US Dial-In:	(888) 203-1112
International Dial-In:	(719) 457-0820
Access Code:	5079681

Except for the historical statements contained in this release, the matters discussed herein, are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements, including our 2015 earnings per share guidance and assumptions, are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "may," "objective," "outlook," "plan," "project," "possible," "potential," "should" and similar expressions. Actual results may vary materially. Forward-looking statements speak only as of the date they are made, and we do not undertake any obligation to update them to reflect changes that occur after that date. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures and the ability of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) to obtain financing on favorable terms; business conditions in the energy industry, including the risk of a slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; 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 Nuclear Regulatory Commission; financial or regulatory accounting policies imposed by regulatory bodies; availability or cost of capital; employee work force factors; the items described under Factors Affecting Results of Operations in Item 7 of Xcel Energy Inc.'s Form 10-K for the year ended Dec. 31, 2014; and the other risk factors listed from time to time by Xcel Energy in reports filed with the Securities and Exchange Commission (SEC), including Risk Factors in Item 1A and Exhibit 99.01 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2014 and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2015.

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Operating revenues				
Electric	$ 2,213,460	$ 2,297,638	$ 4,438,323	$ 4,599,348
Natural gas	284,131	369,127	1,000,127	1,248,815
Other	17,543	18,331	38,903	39,537
Total operating revenues	2,515,134	2,685,096	5,477,353	5,887,700
Operating expenses				
Electric fuel and purchased power	904,705	1,041,322	1,854,837	2,108,643
Cost of natural gas sold and transported	126,667	210,901	599,038	834,729
Cost of sales — other	8,164	7,642	18,213	16,771
Operating and maintenance expenses	594,279	585,604	1,180,109	1,145,747
Conservation and demand side management program expenses	54,141	70,834	107,946	148,380
Depreciation and amortization	274,602	255,307	547,700	501,250
Taxes (other than income taxes)	129,731	116,278	266,357	240,980
Loss on Monticello life cycle management/extended power uprate project	—	—	129,463	—
Total operating expenses	2,092,289	2,287,888	4,703,663	4,996,500
Operating income	422,845	397,208	773,690	891,200
Other income, net	961	82	4,122	3,283
Equity earnings of unconsolidated subsidiaries	8,422	7,811	16,198	15,249
Allowance for funds used during construction — equity	12,641	23,608	25,301	45,515
Interest charges and financing costs				
Interest charges — includes other financing costs of $5,861, $5,614, $11,559 and $11,406, respectively	144,222	139,400	289,162	278,494
Allowance for funds used during construction — debt	(6,165)	(10,113)	(12,309)	(19,661)
Total interest charges and financing costs	138,057	129,287	276,853	258,833
Income before income taxes	306,812	299,422	542,458	696,414
Income taxes	109,881	104,258	193,461	240,029
Net income	$ 196,931	$ 195,164	$ 348,997	$ 456,385
Weighted average common shares outstanding:				
Basic	507,707	503,272	507,359	501,408
Diluted	508,074	503,456	507,747	501,612
Earnings per average common share:				
Basic	$ 0.39	$ 0.39	$ 0.69	$ 0.91
Diluted	0.39	0.39	0.69	0.91
Cash dividends declared per common share	$ 0.32	$ 0.30	$ 0.64	$ 0.60

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

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The diluted earnings and EPS of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. Ongoing diluted EPS for Xcel Energy and by subsidiary is a financial measure not recognized under GAAP. Ongoing diluted EPS is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary, adjusted for certain items, by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate and provide details of Xcel Energy's core earnings and underlying performance. We believe this measurement is useful to investors in facilitating period over period comparisons and evaluating or projecting financial results. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

Note 1. Earnings Per Share Summary

The following table summarizes the diluted EPS for Xcel Energy:

	Three Months Ended June 30		Six Months Ended June 30	
Diluted Earnings (Loss) Per Share	**2015**	**2014**	**2015**	**2014**
Public Service Company of Colorado (PSCo)	$ 0.19	$ 0.18	$ 0.41	$ 0.41
NSP-Minnesota	0.15	0.15	0.32	0.37
Southwestern Public Service Company (SPS)	0.05	0.06	0.08	0.09
NSP-Wisconsin	0.02	0.02	0.07	0.07
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility	0.42	0.42	0.90	0.96
Xcel Energy Inc. and other	(0.03)	(0.03)	(0.05)	(0.05)
Ongoing diluted EPS	0.39	0.39	0.85	0.91
Loss on Monticello life cycle management (LCM)/ extended power uprate (EPU) project [(a)]	—	—	(0.16)	—
GAAP diluted EPS	**$ 0.39**	**$ 0.39**	**$ 0.69**	**$ 0.91**

(a) See Note 7.

PSCo — PSCo's ongoing earnings increased $0.01 per share for the second quarter of 2015 and were flat year-to-date. The positive impact of implementing the Clean Air Clean Jobs Act (CACJA) rider, effective in January 2015, and lower estimated electric earnings test refunds were offset by lower allowance for funds used during construction (AFUDC), higher property taxes, depreciation, and operating and maintenance (O&M) expenses, as well as the impact of weather and weather-normalized sales decline.

NSP-Minnesota — NSP-Minnesota's ongoing earnings were flat for the second quarter of 2015 and decreased $0.05 per share year-to-date. Higher revenue attributable to electric rate cases in Minnesota, North Dakota and South Dakota were more than offset by increases in depreciation, O&M expenses, property taxes and interest charges, as well as unfavorable weather and weather-normalized sales decline.

SPS — SPS' ongoing earnings decreased $0.01 per share for the second quarter of 2015 and year-to-date. Higher electric rates in Texas were offset by higher O&M expenses, depreciation, and lower AFUDC, along with the impact of unfavorable weather.

NSP-Wisconsin — NSP-Wisconsin's ongoing earnings per share were flat for the second quarter of 2015 and year-to-date. Lower O&M expenses and higher electric margins, primarily due to an electric rate increase, were offset by higher depreciation and unfavorable weather.

The following table summarizes significant components contributing to the changes in 2015 EPS compared with the same period in 2014:

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2014 GAAP and ongoing diluted EPS	**$ 0.39**	**$ 0.91**
Components of change — 2015 vs. 2014		
Higher electric margins	0.06	0.11
Lower conservation and demand side management (DSM) program expenses (offset by lower revenues)	0.02	0.05
Higher depreciation and amortization	(0.02)	(0.06)
Higher O&M expenses	(0.01)	(0.04)
Lower AFUDC — equity	(0.02)	(0.04)
Higher taxes (other than income taxes)	(0.02)	(0.03)
Higher effective tax rate (ETR)	(0.01)	(0.03)
Lower natural gas margins	—	(0.02)
Higher interest charges	(0.01)	(0.01)
Other, net	0.01	0.01
2015 ongoing diluted EPS	**0.39**	**0.85**
Loss on Monticello LCM/EPU project [(a)]	—	(0.16)
2015 GAAP diluted EPS	**$ 0.39**	**$ 0.69**

(a) See Note 7.

Note 2. Regulated Utility Results

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

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

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

The percentage decrease in normal and actual HDD, CDD and THI is provided in the following table:

	Three Months Ended June 30			Six Months Ended June 30		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
HDD	(8.1)%	4.5%	(12.4)%	(2.4)%	12.3%	(13.2)%
CDD	(19.1)	0.6	(16.8)	(19.2)	1.0	(17.4)
THI	(20.8)	9.3	(25.1)	(21.0)	8.4	(25.2)

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

	Three Months Ended June 30			Six Months Ended June 30		
	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014	2015 vs. Normal	2014 vs. Normal	2015 vs. 2014
Retail electric	$ (0.013)	$ 0.002	$ (0.015)	$ (0.013)	$ 0.034	$ (0.047)
Firm natural gas	(0.001)	0.001	(0.002)	(0.005)	0.019	(0.024)
Total	$ (0.014)	$ 0.003	$ (0.017)	$ (0.018)	$ 0.053	$ (0.071)

Sales Growth (Decline) — The following tables summarize Xcel Energy and its subsidiaries' sales growth (decline) for actual and weather-normalized sales in 2015:

	Three Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Actual					
Electric residential [(a)]	(4.2)%	0.5%	(6.4)%	(11.4)%	(5.7)%
Electric commercial and industrial	(1.3)	(1.7)	(0.2)	0.5	(2.9)
Total retail electric sales	(2.1)	(1.1)	(2.0)	(2.8)	(3.6)
Firm natural gas sales	(16.7)	(8.0)	(31.6)	(26.0)	N/A

	Three Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Weather-normalized					
Electric residential [(a)]	(2.3)%	(1.2)%	(3.0)%	(6.3)%	(0.5)%
Electric commercial and industrial	(0.7)	(2.3)	0.4	1.4	(1.3)
Total retail electric sales	(1.2)	(1.9)	(0.6)	(0.7)	(1.3)
Firm natural gas sales	(14.9)	(13.7)	(17.4)	(16.6)	N/A

	Six Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Actual					
Electric residential [(a)]	(4.6)%	(1.5)%	(6.3)%	(9.2)%	(4.2)%
Electric commercial and industrial	(0.6)	(0.7)	(0.9)	1.0	(0.6)
Total retail electric sales	(1.8)	(0.9)	(2.6)	(2.2)	(1.4)
Firm natural gas sales	(11.8)	(9.1)	(15.9)	(13.5)	N/A

	Six Months Ended June 30				
	Xcel Energy	PSCo	NSP-Minnesota	NSP-Wisconsin	SPS
Weather-normalized					
Electric residential [(a)]	(1.3)%	(1.1)%	(1.8)%	(3.4)%	0.8%
Electric commercial and industrial	0.1	(0.6)	—	2.3	0.3
Total retail electric sales	(0.4)	(0.8)	(0.5)	0.6	0.3
Firm natural gas sales	(2.0)	(2.5)	(1.4)	—	N/A

(a) Extreme weather variations and additional factors such as windchill and cloud cover may not be reflected in weather-normalized and actual growth estimates.

<u>Weather-normalized Electric Year-to-Date Growth (Decline)</u>

- SPS' commercial and industrial (C&I) growth was driven by continued expansion from oil and gas exploration and production in the Southeastern New Mexico, Permian Basin area. This was partially offset by the impact of wet weather which resulted in less irrigation by agricultural customers. Residential growth reflects an increased number of customers as well as greater use per customer.
- 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. Residential decline was primarily attributable to lower use per customer.

- PSCo’s C&I decline was primarily due to customers in fracking and certain manufacturing industries. Residential decrease was primarily the result of weaker use per customer, partially offset by customer growth.
- NSP-Minnesota’s C&I electric sales were flat as a result of higher use for large customer class (particularly due to greater usage in the petroleum industry), and an increase in the number of customers in both the small and large classes, offset by lower use for small customers in various industries. The residential decrease was due to less use per customer, partially offset by increasing customer growth.

Weather-normalized Natural Gas Decline

- Across natural gas service territories, lower natural gas sales reflect a decline in customer use.

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	**2015**	**2014**	**2015**	**2014**
Electric revenues	$ 2,213	$ 2,298	$ 4,438	$ 4,599
Electric fuel and purchased power	(905)	(1,041)	(1,855)	(2,109)
Electric margin	$ 1,308	$ 1,257	$ 2,583	$ 2,490

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

(Millions of Dollars)	**Three Months Ended June 30 2015 vs. 2014**	**Six Months Ended June 30 2015 vs. 2014**
Non-fuel riders [(a)] [(b)]	$ 31	$ 65
Retail rate increases [(b)]	25	48
PSCo earnings test refund	24	35
NSP-Wisconsin fuel recovery	3	9
Estimated impact of weather	(12)	(37)
Conservation and DSM program revenues (offset by expenses)	(13)	(28)
Retail sales decline, excluding weather impact	(9)	(10)
Other, net	2	11
Total increase in electric margin	$ 51	$ 93

(a) Increases relate primarily to the new CACJA rider in Colorado ($28 million and $52 million, respectively) and Transmission Cost Recovery (TCR) rider in Minnesota ($5 million and $14 million, respectively).

(b) Increase due to rate proceedings in Minnesota, Texas, South Dakota, North Dakota, New Mexico, Wisconsin and Michigan. These increases were partially offset by a decline in Colorado retail base rates, which was more than offset by increased CACJA rider revenue as approved by the CPUC in the first quarter of 2015.

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	**2015**	**2014**	**2015**	**2014**
Natural gas revenues	$ 284	$ 369	$ 1,000	$ 1,249
Cost of natural gas sold and transported	(127)	(211)	(599)	(835)
Natural gas margin	$ 157	$ 158	$ 401	$ 414

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

(Millions of Dollars)	Three Months Ended June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Estimated impact of weather	$ (2)	$ (19)
Conservation and DSM program revenues (offset by expenses)	(3)	(11)
Retail sales decline, excluding weather impact	(7)	(3)
Integrity rider (Colorado) and infrastructure rider (Minnesota), partially offset in expenses	11	18
Other, net	—	2
Total decrease in natural gas margin	$ (1)	$ (13)

O&M Expenses — O&M expenses increased $8.7 million, or 1.5 percent, for the second quarter of 2015 and $34.4 million, or 3.0 percent, for the six months ended June 30, 2015. The year-to-date increase in O&M is primarily due to the timing of planned maintenance and overhauls at a number of our generation facilities. We continue to expect that the change in annual O&M expense for 2015 to be within a range of 0 percent to 2 percent, consistent with our annual guidance assumptions.

(Millions of Dollars)	Three Months Ended June 30 2015 vs. 2014	Six Months Ended June 30 2015 vs. 2014
Plant generation costs	$ 5	$ 21
Employee benefits	4	8
Nuclear plant operations	(1)	3
Other, net	1	2
Total increase in O&M expenses	$ 9	$ 34

Conservation and DSM Program Expenses — Conservation and DSM program expenses decreased $16.7 million for the second quarter of 2015 and $40.4 million for the six months ended June 30, 2015. The decreases were primarily attributable to lower electric and gas recovery rates at NSP-Minnesota and PSCo. Lower conservation and DSM program expenses are generally offset by lower revenues.

Depreciation and Amortization — Depreciation and amortization increased $19.3 million, or 7.6 percent, for the second quarter of 2015 and $46.5 million, or 9.3 percent, year-to-date. Increases were primarily attributed to normal system expansion and lower amortization of the excess depreciation reserve in Minnesota, partially offset by Minnesota's amortization of the Department of Energy settlement.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $13.5 million, or 11.6 percent, for the second quarter of 2015 and $25.4 million, or 10.5 percent, for the six months ended June 30, 2015. Increases were due to higher property taxes primarily in Colorado and Minnesota.

AFUDC, Equity and Debt — AFUDC decreased $14.9 million for the second quarter of 2015 and $27.6 million year-to-date. Decreases were primarily due to the implementation of the CACJA rider on Jan. 1, 2015, facilitating earlier and alternative recovery of construction costs.

Interest Charges — Interest charges increased $4.8 million, or 3.5 percent, for the second quarter of 2015 and $10.7 million, or 3.8 percent, for the six months ended June 30, 2015. Increases were primarily due to higher long-term debt levels, partially offset by refinancings at lower interest rates.

Income Taxes — Income tax expense increased $5.6 million for the second quarter of 2015 compared with the same period in 2014. The increase was primarily due to higher pretax earnings in second quarter of 2015, partially offset by decreased permanent plant-related adjustments in 2015 and a tax benefit for an income exclusion in 2014. The ETR was 35.8 percent for the second quarter of 2015 compared with 34.8 percent for the same period in 2014. The higher ETR for 2015 was primarily due to the adjustments referenced above.

Income tax expense decreased $46.6 million for the first six months of 2015 compared with the same period in 2014. The decrease in income tax expense was primarily due to lower pretax earnings in six months ended June 30, 2015, partially offset by decreased permanent plant-related adjustments in 2015, the successful resolution of a 2010-2011 IRS audit issue in 2014 and a tax benefit for an income exclusion in 2014. The ETR was 35.7 percent for the first six months of 2015, compared to 34.5 percent for the first six months of 2014 primarily due to these adjustments.

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

Following is the capital structure of Xcel Energy:

(Billions of Dollars)	June 30, 2015	Percentage of Total Capitalization
Current portion of long-term debt	$ 0.7	3%
Short-term debt	0.4	2
Long-term debt	11.9	51
Total debt	13.0	56
Common equity	10.3	44
Total capitalization	$ 23.3	100%

Credit Facilities — As of July 27, 2015, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet liquidity needs:

(Millions of Dollars)	Credit Facility [(a)]	Drawn [(b)]	Available	Cash	Liquidity
Xcel Energy Inc.	$ 1,000	$ 60	$ 940	$ —	$ 940
PSCo	700	35	665	1	666
NSP-Minnesota	500	184	316	1	317
SPS	400	257	143	1	144
NSP-Wisconsin	150	—	150	5	155
Total	$ 2,750	$ 536	$ 2,214	$ 8	$ 2,222

(a) These credit facilities expire in October 2019.
(b) Includes outstanding commercial paper and letters of credit.

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

As of July 27, 2015, the following represents the credit ratings assigned to Xcel Energy Inc. and its utility subsidiaries:

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

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

During 2015, Xcel Energy Inc. and its utility subsidiaries completed the following bond issuances:

- In May, PSCo issued $250 million of 2.9 percent first mortgage bonds due May 15, 2025;
- In June, Xcel Energy Inc. issued $250 million of 1.2 percent senior notes due June 1, 2017 and $250 million of 3.3 percent senior notes due June 1, 2025; and
- In June, NSP-Wisconsin issued $100 million of 3.3 percent first mortgage bonds due June 15, 2024.

Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following in the second half of 2015:

- NSP-Minnesota plans to issue approximately $600 million of first mortgage bonds; and
- SPS plans to issue approximately $200 million of first mortgage bonds.

Xcel Energy does not anticipate issuing any additional equity, beyond its dividend reinvestment program and benefit programs, for 2015-2019, based on its current capital expenditure plan. Financing plans are subject to change, depending on capital expenditures, internal cash generation, market conditions and other factors.

Note 4. Rates and Regulation

NSP-Minnesota – Minnesota 2014 Multi-Year Electric Rate Case — In November 2013, NSP-Minnesota filed a two-year electric rate case with the Minnesota Public Utilities Commission (MPUC). The rate case was based on a requested return on equity (ROE) of 10.25 percent, a 52.5 percent equity ratio, a 2014 average electric rate base of $6.67 billion and an additional average rate base of $412 million in 2015. The NSP-Minnesota electric rate case initially reflected a requested increase in revenues of approximately $193 million, or 6.9 percent, in 2014 and an additional $98 million, or 3.5 percent, in 2015. The request included a proposed rate moderation plan for 2014 and 2015. In December 2013, the MPUC approved interim rates of $127 million, effective Jan. 3, 2014, subject to refund.

In 2014, NSP-Minnesota revised its requested rate increase to $115.3 million for 2014 and to $106.0 million for 2015, for a total combined unadjusted increase of $221.3 million.

In May 2015, the MPUC ordered a 2014 rate increase and a 2015 step increase. The total increase was estimated to be $166 million, or 5.9 percent, based on a 9.72 percent ROE and 52.50 percent equity ratio. The MPUC also approved a three-year, decoupling pilot with a 3 percent cap on base revenue for the residential and small commercial and industrial classes, based on actual sales, effective Jan. 1, 2016. The decoupling mechanism would eliminate the impact of changes in electric sales due to conservation and weather variability for these classes.

In July 2015, the MPUC deliberated on requests for reconsideration of its order. The MPUC determined the Monticello Extended Power Uprate (EPU) project is not used-and-useful until final approval related to the full EPU uprate condition is received from the Nuclear Regulatory Commission (NRC). NSP-Minnesota expects that $13.8 million will be excluded from final rates, as approval from the NRC had not been received as of June 30, 2015. Monticello achieved the full EPU uprate level of 671 megawatts in June 2015 and received final NRC compliance approval in July 2015, thereby satisfying the used-and-useful conditions established by the MPUC. The MPUC also approved 2015 interim rates effective March 3, 2015 and stated that the 2014 interim rate refund obligation be netted against the 2015 interim rate revenue under-collections.

The MPUC's decision resulted in an estimated 2015 annual rate increase of $149.4 million or 5.3 percent. NSP-Minnesota anticipates reducing the 2014 refund obligation by approximately $6 million for the change in the interest rate applied to interim refunds and other items.

The following tables outline NSP-Minnesota's filed request and the impact of the MPUC's decisions made in May and July:

2014 Rate Request (Millions of Dollars)	NSP-Minnesota	MPUC May Decision
NSP-Minnesota's filed rate request	$ 192.7	$ 192.7
Sales forecast (with true-up to 12 months of actual weather-normalized sales)	(38.5)	(37.5)
ROE	—	(31.9)
Monticello EPU cost recovery	(12.2)	(37.6)
Property taxes (with true-up to actual 2014 accruals)	(13.2)	(13.2)
Prairie Island EPU cost recovery	(5.1)	(5.0)
Health care, pension and other benefits	(1.9)	(3.1)
Other, net	(6.5)	(5.5)
Total 2014	$ 115.3	$ 58.9

2015 Rate Request (Millions of Dollars)	NSP-Minnesota	MPUC May Decision
NSP-Minnesota's filed rate request	$ 98.5	$ 98.5
Monticello EPU cost recovery	11.7	35.4
Depreciation / Retirements	—	(0.5)
Property taxes	(3.3)	(3.3)
Production tax credits to be included in base rates	(11.1)	(11.1)
U.S. Department of Energy (DOE) settlement proceeds	10.1	10.1
Emission chemicals	(1.6)	(1.6)
Other, net	1.7	(2.3)
Total 2015 step increase - prior to Monticello Life Cycle Management (LCM)/EPU cost disallowance	$ 106.0	$ 125.2
Total for 2014 and 2015 step increase - prior to Monticello LCM/EPU cost disallowance	$ 221.3	$ 184.1
Monticello LCM/EPU cost disallowance	—	(18.0)
Total for 2014 and 2015 step increase - including Monticello LCM/EPU cost disallowance	$ 221.3	$ 166.1

(Millions of Dollars)	MPUC July Decision
2015 annual rate increase - based on MPUC May order	$ 166.1
Reconsideration/clarification adjustments:	
2015 Monticello EPU used-and-useful adjustment	(13.8)
2014 property tax final true-up	(3.1)
Other, net	0.2
Total 2015 annual rate increase	$ 149.4
Impact of interim rate effective March 3, 2015	(3.6)
Estimated 2015 revenue impact	$ 145.8

NSP-Minnesota – South Dakota 2015 Electric Rate Case — In June 2014, NSP-Minnesota filed a request with the South Dakota Public Utilities Commission (SDPUC) to increase electric rates by $15.6 million annually, or 8.0 percent, effective Jan. 1, 2015. Interim rates of $15.6 million, subject to refund, went into effect in January 2015.

In June 2015, the SDPUC approved a settlement agreement allowing a base rate increase of approximately $6.9 million, or 3.6 percent, and providing revisions to the existing Infrastructure rider, which will recover additional net revenue of $0.9 million. Combined, the overall revenue increase in base rates and the Infrastructure rider for 2015 is approximately $7.8 million, or 4.0 percent. New rates began in July 2015. In addition, there is a moratorium on base rate increases until Jan. 1, 2018.

The settlement also includes an earnings test with a sharing mechanism. If South Dakota's weather normalized earnings exceed a certain level, NSP-Minnesota will refund 50 percent of the excess earnings to customers.

NSP-Wisconsin – Wisconsin 2016 Electric and Gas Rate Case — On May 29, 2015, NSP-Wisconsin filed a request with the Public Service Commission of Wisconsin (PSCW) to increase rates for electric and natural gas service effective Jan. 1, 2016. NSP-Wisconsin requested an overall increase in annual electric rates of $27.4 million, or 3.9 percent, and an increase in natural gas rates of $5.9 million, or 5.0 percent.

The rate filing is based on a 2016 forecast test year, a return on equity of 10.2 percent, an equity ratio of 52.5 percent and a forecasted average net investment rate base of approximately $1.2 billion for the electric utility and $111.2 million for the natural gas utility.

Key dates in the procedural schedule are as follows:

- Staff and Intervenor Direct Testimony — Oct. 1, 2015;
- Rebuttal Testimony — Oct. 19, 2015;
- Sur-Rebuttal Testimony — Oct. 27, 2015;
- Technical Hearing — Oct. 29, 2015;
- Initial Brief — Nov. 12, 2015;
- Reply Brief — Nov. 19, 2015; and
- A PSCW decision is anticipated in December 2015.

PSCo – Colorado 2015 Multi-Year Gas Rate Case — In March 2015, PSCo filed a multi-year request with the CPUC to increase Colorado retail natural gas base rates by $40.5 million, or 3.5 percent, in 2015, with subsequent step increases of $7.6 million, or 0.7 percent, in 2016 and $18.1 million, or 1.5 percent, in 2017.

The request is based on a historic test year (HTY) ended June 30, 2014 adjusted for known and measurable expenses and capital additions for each of the subsequent periods in the multi-year plan and an equity ratio of 56 percent. The rate case requests an ROE of 10.1 percent for 2015 and 2016 and 10.3 percent for 2017, and a rate base of $1.26 billion for 2015, $1.31 billion for 2016 and $1.36 billion for 2017.

PSCo also proposed a stay-out provision, in which PSCo would not request implementation of new rates prior to January 2018, and implementation of an earnings test for 2016 through 2017.

In addition, PSCo requested an extension of its pipeline system integrity adjustment (PSIA) rider through 2020 to recover costs associated with its pipeline integrity efforts. The request to extend and modify the PSIA rider has an expected negative revenue impact of approximately $0.1 million in 2015 and would provide incremental revenue of $21.7 million for 2016 and $21.2 million for 2017. The following table summarizes the request:

(Millions of Dollars)	2015	2016 Step	2017 Step
Total base rate increase	40.5	7.6	18.1
Incremental PSIA rider revenues	(0.1)	21.7	21.2
Total revenue impact	$ 40.4	$ 29.3	$ 39.3

In June 2015, intervenors, including the CPUC Staff (Staff) and the Office of Consumer Counsel (OCC), filed testimony.

- Staff recommended a base rate decrease of $14.7 million, based on an ROE of 9.0 percent and a 47.04 percent equity ratio;
- OCC recommended a base rate increase of $5.8 million, based on an ROE of 9.0 percent and a 52.70 percent equity ratio;
- A multi-year plan was opposed by both the Staff and OCC;
- The Staff recommended deferring costs related to incremental property taxes and safety programs which are expected to be approximately $4.2 million in 2016 and $9.0 million in 2017; and
- The Staff opposed PSCo’s proposed earnings test and the stay out provision.

Regarding the PSIA:

- The Staff proposed extending the PSIA rider for three years;
- The Staff recommended approximately $32.6 million of PSIA costs would be transferred to base rates, effective Jan. 1, 2016, in addition to the Staff's proposed 2015 base rate adjustment; and
- The OCC recommended the PSIA rider expire on June 30, 2016 and any costs be included in base rates through a step increase.

The Staff and OCC's 2015 base rate recommendations are summarized in the following table:

(Millions of Dollars)	Staff	OCC
PSCo's filed 2015 base rate request	$ 40.5	$ 40.5
ROE	(12.8)	(13.7)
Capital structure and cost of debt	(12.8)	(4.8)
Cherokee pipeline adjustment	(11.2)	4.8
Move to 2014 historical test year	(10.5)	(16.4)
O&M expenses	(3.5)	(2.7)
Other, net	(4.4)	(1.9)
Total adjustments	$ (55.2)	$ (34.7)
Recommended (decrease) increase	$ (14.7)	$ 5.8

The Staff's recommendation for the PSIA rider is as follows:

(Millions of Dollars)	2016	2017
PSCo's filed incremental PSIA request	$ 21.7	$ 21.2
Transfer PSIA O&M to base rates	(24.1)	(2.0)
ROE and capital structure	(8.2)	(3.6)
Transfer meter replacement program from base rates to PSIA	1.7	1.7
Total	$ (8.9)	$ 17.3

On July 20, 2015, PSCo filed rebuttal testimony, maintaining its request for a multi-year plan and requested ROEs and reflecting the most recent sales forecast. PSCo also accepts portions of the Staff's position regarding the PSIA rider. PSCo's rebuttal testimony, compared to its initial filed base rate and rider request are summarized as follows:

(Millions of Dollars)	2015	2016 Step	2017 Step
PSCo's filed base rate request	$ 40.5	$ 7.6	$ 18.1
Shift O&M expenses between PSIA and base rates	—	7.0	6.4
Rebuttal corrections and adjustments	—	—	(7.7)
Total base rate request	$ 40.5	$ 14.6	$ 16.8
Incremental PSIA rider revenues	(0.1)	14.7	21.7
Total revenue impact from rebuttal	$ 40.4	$ 29.3	$ 38.5

If PSCo's revised request is accepted, PSIA revenue is projected to be $67.0 million in 2015, $81.7 million in 2016 and $103.4 million in 2017.

The next steps in the procedural schedule are as follows:

- Sur-Rebuttal Testimony — Aug. 3, 2015;
- Evidentiary Hearing — Aug. 18 - Aug. 31, 2015;
- Interim Rates (subject to refund) — Oct. 1, 2015; and
- Final CPUC Decision — No later than Jan. 20, 2016

SPS – Texas 2015 Electric Rate Case — In December 2014, SPS filed a retail electric rate case in Texas seeking an overall increase in annual revenue of approximately $64.8 million, or 6.7 percent. The filing was based on a HTY ending June 2014, adjusted for known and measurable changes, a ROE of 10.25 percent, an electric rate base of approximately $1.6 billion and an equity ratio of 53.97 percent. In March 2015, SPS revised its requested increase to $58.9 million based on updated information.

SPS is seeking a waiver of the Public Utility Commission of Texas (PUCT) post-test year adjustment rule which would allow for inclusion of $392 million (SPS total company) additional capital investment for the period July 1, 2014 through Dec. 31, 2014.

In May 2015, several intervenors filed direct testimony in response to SPS' rate request, including the Alliance of Xcel Municipalities (AXM), the Office of Public Utility Counsel (OPUC), and the PUCT Staff (Staff).

- AXM recommended a rate decrease of $13.6 million, an ROE of 9.40 percent and an equity ratio of 53.97 percent.
- The OPUC recommended a rate increase of $1.8 million, an ROE of 9.20 percent and an equity ratio of 52.38 percent.
- The Staff recommended a rate decrease of $2.6 million, an ROE of 9.30 percent and an equity ratio of 53.97 percent.

In June 2015, SPS filed rebuttal testimony supporting a revised rate increase of approximately $42 million, or 4.4 percent.

(Millions of Dollars)	AXM	OPUC	Staff	SPS Rebuttal Testimony
SPS' revised rate request	$ 58.9	$ 58.9	$ 58.9	$ 58.9
Investment for capital expenditures — post-test year adjustments	(11.3)	(23.8)	(23.8)	—
Lower ROE	(10.9)	(13.5)	(12.1)	—
Rate base adjustments (largely the removal of the prepaid pension asset)	(6.2)	(6.8)	—	—
O&M expense adjustments	(13.7)	(11.0)	(7.9)	(1.6)
Depreciation expense	(13.3)	—	—	—
Property taxes	—	(1.2)	(4.4)	(1.8)
Revenue adjustments	(2.2)	(0.2)	—	—
Wholesale load reductions	(13.2)	—	(11.1)	—
Southwest Power Pool transmission expansion plan	—	—	—	(7.3)
Other, net	(1.7)	(0.6)	(2.2)	(1.8)
Total recommendation	$ (13.6)	$ 1.8	$ (2.6)	$ 46.4
Adjustment to move rate case expenses to a separate docket	—	—	—	(4.3)
Recommendation, excluding rate case expenses	$ (13.6)	$ 1.8	$ (2.6)	$ 42.1

New rates will be made effective retroactive to June 11, 2015 as established by the PUCT. Hearings were completed in July 2015. A PUCT decision is expected in the fourth quarter of 2015.

SPS – New Mexico 2015 Electric Rate Case — In June 2015, SPS filed an electric rate case with the New Mexico Public Regulation Commission (NMPRC) for an increase in non-fuel base rates of $31.5 million and a base fuel decrease of $30.1 million. The rate filing was based on a 2016 forecast test year (FTY), a requested return on equity of 10.25 percent, a jurisdictional electric rate base of $777.9 million and an equity ratio of 53.97 percent.

In June 2015, SPS' rate case application was dismissed by the NMPRC. The NMPRC determined that the filing did not comply with its new interpretation of the statute regarding FTY periods and the corresponding timing of a rate case submission in relation to the FTY used in the case. This new interpretation occurred during the recent Public Service Company of New Mexico rate case.

In July, SPS filed an appeal with the New Mexico Supreme Court. In addition, SPS plans to file a rate case later this year.

Note 5. Legislation Passed During 2015

Minnesota Legislation — In June 2015, the Minnesota Governor signed the Jobs and Energy bill into law. The legislation includes more cost -recovery options and the potential for longer-term multi-year rates plans, which could provide certainty for NSP-Minnesota and its customers. This bill provides:

- Increased flexibility for utilities to submit a multi-year plan (MYP) of up to five years;
- The potential for full capital recovery for all proposed years;
- O&M cost recovery based on an industry index;
- Distribution costs that facilitate grid modernization are eligible for rider recovery;
- Natural gas extension costs for unserved areas can be socialized and are eligible for rider recovery;
- Recovery of plant closure costs, should the MPUC order early plant closure; and
- Implementation of interim rates for the first and second years of the MYP.

Texas Legislation — In June 2015, the Texas Governor signed HB 1535 into law. As a result, SPS may reduce regulatory lag through earlier inclusion of certain capital additions in rate base, as well as expediting the implementation of new rates. Key provisions of the bill are as follows:

- Utilities may include actual and estimated post-test year capital additions up through 30-days before the filing date;
- A new natural gas generating unit may be included in rate base as long as it is in service before the proposed effective rate date;
- Rates will go into effect 155 days after filing (previously it was 185 days). If the case is not final by this date, then a utility can go back and surcharge; and
- Establishes time limits for the PUCT to rule on a new generation plant request for a certificate of convenience and necessity.

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

Xcel Energy 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.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-normalized retail electric utility sales are projected to increase approximately 0.5 percent.
- Weather-normalized retail firm natural gas sales are projected to decline approximately 2 percent.
- Capital rider revenue is projected to increase by $155 million to $165 million over 2014 levels.
- 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 $130 million to $150 million over 2014 levels.
- 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 $30 million to $40 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; and
- Maintain senior unsecured debt credit ratings in the BBB+ to A range.

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

Note 7. Non-GAAP Reconciliation

Xcel Energy’s reported earnings are prepared in accordance with GAAP. Xcel Energy’s management believes that ongoing earnings, or GAAP earnings adjusted for certain items, reflect management’s performance in operating the company and provides a meaningful representation of the underlying performance of Xcel Energy’s core business. In addition, Xcel Energy’s management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors and when communicating its earnings outlook to analysts and investors. This non-GAAP financial measure should not be considered as an alternative to measures calculated and reported in accordance with GAAP.

The following table provides a reconciliation of ongoing earnings to GAAP earnings (net income):

	Three Months Ended June 30		Six Months Ended June 30	
(Thousands of Dollars)	**2015**	**2014**	**2015**	**2014**
Ongoing earnings	$ 196,931	$ 195,164	$ 428,148	$ 456,385
Loss on Monticello LCM/EPU project	—	—	(79,151)	—
GAAP earnings	$ 196,931	$ 195,164	$ 348,997	$ 456,385

Loss on Monticello LCM/EPU Project — In March 2015, the MPUC approved full recovery, including a return, on $415 million of the project costs, inclusive of AFUDC, but only allow recovery of the remaining $333 million of costs with no return on this portion of the investment for years 2015 and beyond. As a result of this decision, Xcel Energy recorded a pre-tax charge of approximately $129 million, or $79 million net of tax, in the first quarter of 2015. Given the nature of this specific item, it has been excluded from ongoing earnings.

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

	Three Months Ended June 30	
	2015	**2014**
Operating revenues:		
Electric and natural gas	$ 2,497,591	$ 2,666,765
Other	17,543	18,331
Total operating revenues	2,515,134	2,685,096
Net income	$ 196,931	$ 195,164
Weighted average diluted common shares outstanding	508,074	503,456
Components of EPS — Diluted		
Regulated utility	$ 0.42	$ 0.42
Xcel Energy Inc. and other costs	(0.03)	(0.03)
Ongoing diluted EPS	**0.39**	**0.39**
Loss on Monticello LCM/EPU project [(a)]	—	—
GAAP diluted EPS	**$ 0.39**	**$ 0.39**

	Six Months Ended June 30	
	2015	**2014**
Operating revenues:		
Electric and natural gas	$ 5,438,450	$ 5,848,163
Other	38,903	39,537
Total operating revenues	5,477,353	5,887,700
Net income	$ 348,997	$ 456,385
Weighted average diluted common shares outstanding	507,747	501,612
Components of EPS — Diluted		
Regulated utility	$ 0.90	$ 0.96
Xcel Energy Inc. and other costs	(0.05)	(0.05)
Ongoing diluted EPS	**0.85**	**0.91**
Loss on Monticello LCM/EPU project [(a)]	(0.16)	—
GAAP diluted EPS	**$ 0.69**	**$ 0.91**
Book value per share	$ 20.26	$ 19.64

[(a)] See Note 7.