XCEL ENERGY INC
Form 10-Q
August 03, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2012
or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number: 001-3034

Xcel Energy Inc.
(Exact name of registrant as specified in its charter)

Minnesota (State or other jurisdiction of incorporation or organization)	41-0448030 (I.R.S. Employer Identification No.)
414 Nicollet Mall Minneapolis, Minnesota (Address of principal executive offices)	55401 (Zip Code)

(612) 330-5500
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. xYes oNo

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 and Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). xYes oNo

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
oYes xNo

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

Class	Outstanding at July 26, 2012
Common Stock, $2.50 par value	487,553,810 shares

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This Form 10-Q is filed by Xcel Energy Inc. Xcel Energy Inc. wholly owns the following subsidiaries: Northern States Power Company, a Minnesota corporation (NSP-Minnesota); Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin); Public Service Company of Colorado (PSCo); and Southwestern Public Service Company (SPS). Xcel Energy Inc. and its consolidated subsidiaries are also referred to herein as Xcel Energy. NSP-Minnesota, NSP-Wisconsin, PSCo and SPS are also referred to collectively as utility subsidiaries. Additional information on the wholly owned subsidiaries is available on various filings with the Securities and Exchange Commission (SEC).

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PART I — FINANCIAL INFORMATION
Item 1 — FINANCIAL STATEMENTS

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	
	2012	2011	2012	2011
Operating revenues				
Electric	$ 2,036,829	$ 2,128,397	$ 3,973,611	$ 4,158,369
Natural gas	221,313	291,538	842,348	1,056,887
Other	16,526	18,287	36,788	39,506
Total operating revenues	2,274,668	2,438,222	4,852,747	5,254,762
Operating expenses				
Electric fuel and purchased power	854,373	989,413	1,718,353	1,921,241
Cost of natural gas sold and transported	89,759	163,056	507,705	706,432
Cost of sales — other	5,944	6,891	13,248	14,946
Operating and maintenance expenses	534,014	532,170	1,044,698	1,042,197
Conservation and demand side management program expenses	58,615	65,497	122,322	140,795
Depreciation and amortization	226,641	229,264	455,313	453,987
Taxes (other than income taxes)	99,632	92,489	205,256	189,059
Total operating expenses	1,868,978	2,078,780	4,066,895	4,468,657
Operating income	405,690	359,442	785,852	786,105
Other income, net	728	979	4,465	5,745
Equity earnings of unconsolidated subsidiaries	7,502	7,677	14,660	15,390
Allowance for funds used during construction — equity	15,194	13,606	28,644	26,850
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,036, $6,185, $12,116 and $11,445, respectively	151,921	146,338	303,751	290,692
Allowance for funds used during construction — debt	(7,683)	(7,838)	(14,290)	(15,274)
Total interest charges and financing costs	144,238	138,500	289,461	275,418
Income from continuing operations before income taxes	284,876	243,204	544,160	558,672
Income taxes	101,801	84,533	177,316	196,534
Income from continuing operations	183,075	158,671	366,844	362,138
(Loss) income from discontinued operations, net of tax	(15)	91	109	193
Net income	183,060	158,762	366,953	362,331
Dividend requirements on preferred stock	-	1,060	-	2,120
Earnings available to common shareholders	$ 183,060	$ 157,702	$ 366,953	$ 360,211
Weighted average common shares outstanding:				
Basic	487,717	484,918	487,538	484,283

Diluted	488,017	485,241	488,006	484,775
Earnings per average common share:				
Basic	$ 0.38	$ 0.33	$ 0.75	$ 0.74
Diluted	0.38	0.33	0.75	0.74
Cash dividends declared per common share	$ 0.27	$ 0.26	$ 0.53	$ 0.51

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)
(amounts in thousands)

	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
Net income	$ 183,060	$ 158,762	$ 366,953	$ 362,331
Other comprehensive (loss) income				
Pension and retiree medical benefits:				
Amortization of losses included in net periodic benefit cost, net of tax of $647, $525, $1,269 and $1,076, respectively	932	754	1,827	1,548
Derivative instruments:				
Net fair value (decrease) increase, net of tax of $(23,164), $(40), $(6,673) and $105, respectively	(35,727)	(38)	(10,335)	206
Reclassification of losses to net income, net of tax of $158, $140, $314 and $287, respectively	182	148	363	306
	(35,545)	110	(9,972)	512
Marketable securities:				
Net fair value increase, net of tax of $83, $0, $119 and $35, respectively	122	-	174	50
Other comprehensive (loss) income	(34,491)	864	(7,971)	2,110
Comprehensive income	$ 148,569	$ 159,626	$ 358,982	$ 364,441

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)
(amounts in thousands)

	Six Months Ended June 30	
	2012	2011
Operating activities		
Net income	$ 366,953	$ 362,331
Remove income from discontinued operations	(109)	(193)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	464,117	463,013
Conservation and demand side management program amortization	3,765	6,078
Nuclear fuel amortization	49,765	43,732
Deferred income taxes	278,358	197,637
Amortization of investment tax credits	(3,104)	(3,160)
Allowance for equity funds used during construction	(28,644)	(26,850)
Equity earnings of unconsolidated subsidiaries	(14,660)	(15,390)
Dividends from unconsolidated subsidiaries	8,028	16,931
Share-based compensation expense	17,249	20,299
Net derivative losses	7,325	16,802
Changes in operating assets and liabilities:		
Accounts receivable	(928)	38,914
Accrued unbilled revenues	139,012	117,836
Inventories	145,095	76,028
Other current assets	(61,291)	52,397
Accounts payable	(177,076)	32,116
Net regulatory assets and liabilities	12,912	(41,888)
Other current liabilities	(117,653)	(78,110)
Pension and other employee benefit obligations	(168,898)	(131,892)
Change in other noncurrent assets	(40,893)	13,119
Change in other noncurrent liabilities	(14,027)	(36,634)
Net cash provided by operating activities	865,296	1,123,116
Investing activities		
Utility capital/construction expenditures	(1,103,562)	(1,122,269)
Proceeds from insurance recoveries	24,000	-
Merricourt refund	-	101,261
Merricourt deposit	-	(90,833)
Allowance for equity funds used during construction	28,644	26,850
Purchases of investments in external decommissioning fund	(371,361)	(1,226,504)
Proceeds from the sale of investments in external decommissioning fund	371,361	1,226,491
Investment in WYCO Development LLC	(379)	(961)
Change in restricted cash	94,959	46
Other, net	(24)	(3,964)
Net cash used in investing activities	(956,362)	(1,089,883)
Financing activities		
Proceeds from short-term borrowings, net	262,000	189,600

Proceeds from issuance of long-term debt	111,015	-
Repayments of long-term debt, including reacquisition premiums	(2,455)	(1,741)
Proceeds from issuance of common stock	3,698	3,789
Repurchase of common stock	(18,529)	-
Purchase of common stock for settlement of equity awards	(23,307)	-
Dividends paid	(238,510)	(231,715)
Net cash provided by (used in) financing activities	93,912	(40,067)
Net change in cash and cash equivalents	2,846	(6,834)
Cash and cash equivalents at beginning of period	60,684	108,437
Cash and cash equivalents at end of period	$ 63,530	$ 101,603
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ (281,266)	$ (266,559)
Cash (paid) received for income taxes, net	(5,875)	54,993
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$ 274,350	$ 120,558
Issuance of common stock for reinvested dividends and 401(k) plans	35,543	37,680

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands, except share and per share data)

	June 30, 2012	Dec. 31, 2011
Assets		
Current assets		
Cash and cash equivalents	$ 63,530	$ 60,684
Restricted cash	328	95,287
Accounts receivable, net	645,264	753,120
Accrued unbilled revenues	549,728	688,740
Inventories	473,137	618,232
Regulatory assets	366,226	402,235
Derivative instruments	88,368	64,340
Deferred income taxes	178,470	178,446
Prepayments and other	195,357	121,480
Total current assets	2,560,408	2,982,564
Property, plant and equipment, net	23,047,854	22,353,367
Other assets		
Nuclear decommissioning fund and other investments	1,522,203	1,463,515
Regulatory assets	2,359,097	2,389,008
Derivative instruments	137,015	152,887
Other	193,566	155,926
Total other assets	4,211,881	4,161,336
Total assets	$ 29,820,143	$ 29,497,267
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$ 1,311,594	$ 1,059,922
Short-term debt	481,000	219,000
Accounts payable	871,069	902,078
Regulatory liabilities	193,509	275,095
Taxes accrued	215,159	289,713
Accrued interest	176,855	177,111
Dividends payable	131,565	126,487
Derivative instruments	111,836	157,414
Other	338,635	381,819
Total current liabilities	3,831,222	3,588,639
Deferred credits and other liabilities		
Deferred income taxes	4,320,320	4,020,377
Deferred investment tax credits	84,895	86,743
Regulatory liabilities	1,066,486	1,101,534
Asset retirement obligations	1,695,560	1,651,793
Derivative instruments	253,364	263,906
Customer advances	244,922	248,345
Pension and employee benefit obligations	826,413	1,001,906

Other	217,053	203,313
Total deferred credits and other liabilities	8,709,013	8,577,917
Commitments and contingencies		
Capitalization		
Long-term debt	8,706,403	8,848,513
Common stock — 1,000,000,000 shares authorized of $2.50 par value; 487,285,506 and 486,493,933 shares outstanding at June 30, 2012 and Dec. 31, 2011, respectively	1,218,214	1,216,234
Additional paid in capital	5,316,658	5,327,443
Retained earnings	2,140,639	2,032,556
Accumulated other comprehensive loss	(102,006)	(94,035)
Total common stockholders' equity	8,573,505	8,482,198
Total liabilities and equity	$ 29,820,143	$ 29,497,267

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Three Months Ended June 30, 2012 and 2011						
Balance at March 31, 2011	484,165	$1,210,411	$ 5,241,533	$1,781,386	$ (51,847)	$ 8,181,483
Comprehensive income:						
Net income				158,762		158,762
Other comprehensive income					864	864
Comprehensive income						159,626
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(126,583)		(126,583)
Issuances of common stock	378	945	8,072			9,017
Share-based compensation			12,082			12,082
Balance at June 30, 2011	484,543	$1,211,356	$ 5,261,687	$1,812,505	$ (50,983)	$ 8,234,565
Balance at March 31, 2012	486,936	$1,217,339	$ 5,298,572	$2,089,275	$ (67,515)	$ 8,537,671
Comprehensive income:						
Net income				183,060		183,060
Other comprehensive loss					(34,491)	(34,491)
Comprehensive income						148,569
Dividends declared:						
Common stock				(131,696)		(131,696)
Issuances of common stock	350	875	8,482			9,357
Share-based compensation			9,604			9,604
Balance at June 30, 2012	487,286	$1,218,214	$ 5,316,658	$2,140,639	$ (102,006)	$ 8,573,505

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY (UNAUDITED)
(amounts in thousands)

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Stockholders' Equity
Six Months Ended June 30, 2012 and 2011						
Balance at Dec. 31, 2010	482,334	$1,205,834	$ 5,229,075	$1,701,703	$ (53,093)	$ 8,083,519
Comprehensive income:						
Net income				362,331		362,331
Other comprehensive income					2,110	2,110
Comprehensive income						364,441
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(249,409)		(249,409)
Issuances of common stock	2,209	5,522	9,724			15,246
Share-based compensation			22,888			22,888
Balance at June 30, 2011	484,543	$1,211,356	$ 5,261,687	$1,812,505	$ (50,983)	$ 8,234,565
Balance at Dec. 31, 2011	486,494	$1,216,234	$ 5,327,443	$2,032,556	$ (94,035)	$ 8,482,198
Comprehensive income:						
Net income				366,953		366,953
Other comprehensive loss					(7,971)	(7,971)
Comprehensive income						358,982
Dividends declared:						
Common stock				(258,870)		(258,870)
Issuances of common stock	1,492	3,730	10,770			14,500
Repurchase of common stock	(700)	(1,750)	(16,779)			(18,529)
Purchase of common stock for settlement of equity awards			(23,307)			(23,307)
Share-based compensation			18,531			18,531
Balance at June 30, 2012	487,286	$1,218,214	$ 5,316,658	$2,140,639	$ (102,006)	$ 8,573,505

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XCEL ENERGY INC. AND SUBSIDIARIES
Notes to Consolidated Financial Statements (UNAUDITED)

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly, in accordance with accounting principles generally accepted in the United States of America (GAAP), the financial position of Xcel Energy Inc. and its subsidiaries as of June 30, 2012 and Dec. 31, 2011; the results of its operations, including the components of net income and comprehensive income, and changes in stockholders' equity for the three and six months ended June 30, 2012 and 2011; and its cash flows for the six months ended June 30, 2012 and 2011. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2012 up to the date of issuance of these consolidated financial statements. These statements contain all necessary adjustments and disclosures resulting from that evaluation. The Dec. 31, 2011 balance sheet information has been derived from the audited 2011 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011. These notes to the consolidated financial statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011, filed with the SEC on Feb. 24, 2012. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

1. Summary of Significant Accounting Policies

The significant accounting policies set forth in Note 1 to the consolidated financial statements in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Adopted

Fair Value Measurement — In May 2011, the Financial Accounting Standards Board (FASB) issued Fair Value Measurement (Topic 820) — Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (Accounting Standards Update (ASU) No. 2011-04), which provides clarifications regarding existing fair value measurement principles and disclosure requirements, and also specific new guidance for items such as measurement of instruments classified within stockholders' equity. These requirements were effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy implemented the accounting and disclosure guidance effective Jan. 1, 2012, and the implementation did not have a material impact on its consolidated financial statements. For required fair value measurement disclosures, see Note 8.

Comprehensive Income — In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05), which requires the presentation of the components of net income, the components of other comprehensive income (OCI) and total comprehensive income in either a single continuous financial statement of comprehensive income or in two separate, but consecutive financial statements of net income and comprehensive income. These updates do not affect the items reported in OCI or the guidance for reclassifying such items to net income. These requirements were effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy implemented the financial statement presentation guidance effective Jan. 1, 2012.

Recently Issued

Balance Sheet Offsetting — In December 2011, the FASB issued Balance Sheet (Topic 210) — Disclosures about Offsetting Assets and Liabilities (ASU No. 2011-11), which requires disclosures regarding netting arrangements in agreements underlying derivatives, certain financial instruments and related collateral amounts, and the extent to which an entity's financial statement presentation policies related to netting arrangements impact amounts recorded to the financial statements. These disclosure requirements do not affect the presentation of amounts in the consolidated balance sheets, and are effective for annual reporting periods beginning on or after Jan. 1, 2013, and interim periods within those annual reporting periods. Xcel Energy does not expect the implementation of this disclosure guidance to have a material impact on its consolidated financial statements.

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3.Selected Balance Sheet Data

(Thousands of Dollars)	June 30, 2012	Dec. 31, 2011
Accounts receivable, net		
Accounts receivable	$ 698,853	$ 811,685
Less allowance for bad debts	(53,589)	(58,565)
	$ 645,264	$ 753,120
Inventories		
Materials and supplies	$ 210,197	$ 202,699
Fuel	182,281	236,023
Natural gas	80,659	179,510
	$ 473,137	$ 618,232
Property, plant and equipment, net		
Electric plant	$ 27,717,392	$ 27,254,541
Natural gas plant	3,735,411	3,676,754
Common and other property	1,454,246	1,546,643
Plant to be retired (a)	112,823	151,184
Construction work in progress	1,484,593	1,085,245
Total property, plant and equipment	34,504,465	33,714,367
Less accumulated depreciation	(11,852,561)	(11,658,351)
Nuclear fuel	2,087,663	1,939,299
Less accumulated amortization	(1,691,713)	(1,641,948)
	$ 23,047,854	$ 22,353,367

(a) In 2010, in response to the Clean Air Clean Jobs Act (CACJA), the Colorado Public Utilities Commission (CPUC) approved the early retirement of Cherokee Units 1, 2 and 3, Arapahoe Unit 3 and Valmont Unit 5 between 2011 and 2017. In 2011, Cherokee Unit 2 was retired and in May 2012, Cherokee Unit 1 was retired. Amounts are presented net of accumulated depreciation.

4.Income Taxes

Except to the extent noted below, the circumstances set forth in Note 6 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 appropriately represent, in all material respects, the current status of other income tax matters, and are incorporated herein by reference.

Federal Audit — Xcel Energy files a consolidated federal income tax return. The statute of limitations applicable to Xcel Energy's 2007 federal income tax return expired in September 2011. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expires in September 2012. As of June 30, 2012, there was no federal income tax audit in progress.

State Audits — Xcel Energy files consolidated state tax returns based on income in its major operating jurisdictions of Colorado, Minnesota, Texas, and Wisconsin, and various other state income-based tax returns. As of June 30, 2012, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year
Colorado	2006
Minnesota	2008
Texas	2007

Wisconsin	2007

As of June 30, 2012, there were no state income tax audits in progress.

Unrecognized Tax Benefits — The unrecognized tax benefit balance includes permanent tax positions, which if recognized would affect the annual effective tax rate (ETR). In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the ETR but would accelerate the payment of cash to the taxing authority to an earlier period.

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A reconciliation of the amount of unrecognized tax benefits is as follows:

(Millions of Dollars)	June 30, 2012	Dec. 31, 2011
Unrecognized tax benefit — Permanent tax positions	$ 4.4	$ 4.3
Unrecognized tax benefit — Temporary tax positions	28.1	30.4
Unrecognized tax benefit balance	$ 32.5	$ 34.7

The unrecognized tax benefit amounts were reduced by the tax benefits associated with net operating loss (NOL) and tax credit carryforwards. The amounts of tax benefits associated with NOL and tax credit carryforwards are as follows:

(Millions of Dollars)	June 30, 2012	Dec. 31, 2011
NOL and tax credit carryforwards	$ (31.7)	$ (33.6)

It is reasonably possible that Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the Internal Revenue Service and state audits resume. At this time, due to the uncertain nature of the audit process, an overall range of possible change cannot be reasonably estimated.

The payable for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at June 30, 2012 and Dec. 31, 2011 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2012 or Dec. 31, 2011.

Federal Tax Loss Carryback Claims — Xcel Energy completed an analysis in the first quarter of 2012 on the eligibility of certain expenses that qualified for an extended carryback beyond the typical two-year carryback period. As a result of a higher tax rate in prior years, Xcel Energy recognized a discrete tax benefit of approximately $15 million in the first quarter of 2012.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 12 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

Recently Concluded Regulatory Proceedings — Minnesota Public Utilities Commission (MPUC)

NSP-Minnesota – Minnesota Electric Rate Case — In November 2010, NSP-Minnesota filed a request with the MPUC to increase electric rates in Minnesota for 2011 by approximately $150 million, or an increase of 5.62 percent, and an additional increase of $48.3 million, or 1.81 percent, in 2012. The rate filing was based on a 2011 forecast test year, a requested return on equity (ROE) of 11.25 percent, an electric rate base of $5.6 billion and an equity ratio of 52.56 percent. The MPUC approved an interim rate increase of $123 million, subject to refund, effective Jan. 2, 2011. In August 2011, NSP-Minnesota submitted supplemental testimony, revising its requested rate increase to approximately $122 million for 2011 and an additional increase of approximately $29 million in 2012.

In November 2011, NSP-Minnesota reached a settlement agreement with certain customer intervenors. In February 2012, NSP-Minnesota filed to reduce the interim rate request to $72.8 million to align with the settlement agreement. In March 2012, the MPUC approved the settlement. In May 2012, the MPUC issued an order approving the following:

- A rate increase of approximately $58 million in 2011 and an incremental rate increase of $14.8 million in 2012 based on an ROE of 10.37 percent and an equity ratio of 52.56 percent.
- A reduction to depreciation expense and NSP-Minnesota’s rate request by $30 million.

As of June 30, 2012 and Dec. 31, 2011, NSP-Minnesota recorded a provision for revenue subject to refund of approximately $80 million and $67 million, respectively.

NSP-Minnesota – Minnesota Property Tax Deferral Request — In December 2011, NSP-Minnesota filed a request to defer incremental 2012 property taxes that would not be recovered in base rates, estimated to be approximately $24 million, or alternatively that a property tax rider be approved. In June 2012, the MPUC denied NSP-Minnesota’s request for deferred accounting for incremental property taxes and also denied the request for a property tax rider. There were no incremental 2012 property taxes deferred as a regulatory asset.

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Recently Concluded Regulatory Proceedings — North Dakota Public Service Commission (NDPSC)

NSP-Minnesota – North Dakota Electric Rate Case — In December 2010, NSP-Minnesota filed a request with the NDPSC to increase 2011 electric rates in North Dakota by approximately $19.8 million, or an increase of 12 percent, and a step increase of $4.2 million, or 2.6 percent, in 2012. The rate filing was based on a 2011 forecast test year and included a requested ROE of 11.25 percent, an electric rate base of approximately $328 million and an equity ratio of 52.56 percent. The NDPSC approved an interim rate increase of approximately $17.4 million, subject to refund, effective Feb. 18, 2011.

In May 2011, NSP-Minnesota revised its rate request to approximately $18.0 million, or an increase of 11 percent, for 2011 and $2.4 million, or 1.4 percent, for the additional step increase in 2012. In February 2012, the NDPSC approved the settlement agreement, which provided for a rate increase of $13.7 million in 2011 and an additional step increase of $2.0 million in 2012, based on a 10.4 percent ROE and black box settlement for all other issues. To address 2012 sales coming in below forecast revenue projections, the settlement includes a true-up to 2012 non-fuel revenues plus the settlement rate increase. NSP-Minnesota implemented final rates in May 2012 and issued refunds in June 2012.

Pending and Recently Concluded Regulatory Proceedings — South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota – South Dakota 2011 Electric Rate Case — In June 2011, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $14.6 million annually, effective in 2012. The proposed increase included $0.7 million in revenues currently recovered through automatic recovery mechanisms. The request was based on a 2010 historic test year adjusted for known and measurable changes, a requested ROE of 11 percent, a rate base of $323.4 million and an equity ratio of 52.48 percent. On Jan. 2, 2012, interim rates of $12.7 million were implemented. In June 2012, the SDPUC authorized a rate increase of approximately $8.0 million, based on an ROE of 9.25 percent, and an equity ratio of 53 percent. On July 17, 2012, the SDPUC approved implementation of final rates on Aug. 1, 2012, with refunds to be issued in September 2012.

NSP-Minnesota – South Dakota 2012 Electric Rate Case — On June 29, 2012, NSP-Minnesota filed a request with the SDPUC to increase South Dakota electric rates by $19.4 million annually. The request was based on a 2011 historic test year adjusted for certain known and measurable changes for 2012 and 2013, a requested ROE of 10.65 percent, an average rate base of $367.5 million and an equity ratio of 52.89 percent. A SDPUC decision is expected in late 2012 or early 2013.

NSP-Wisconsin

Pending Regulatory Proceedings — Public Service Commission of Wisconsin (PSCW)

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

The electric rate filing was based on a 2013 forecast test year, a return on equity of 10.40 percent, an equity ratio of 52.50 percent and an average 2013 electric rate base of approximately $788.6 million. The natural gas rate request was solely due to a proposal to recover the initial costs associated with the environmental cleanup of a site in Ashland, Wis., which includes the site of a former manufactured gas plant (MGP) that was owned by a predecessor company to NSP-Wisconsin.

A PSCW decision is anticipated in the fourth quarter of 2012.

PSCo

Recently Concluded Regulatory Proceedings — CPUC

PSCo 2011 Electric Rate Case — In November 2011, PSCo filed a request with the CPUC to increase Colorado retail electric rates by $141.9 million. The request was based on a 2012 forecast test year, a 10.75 percent ROE, an electric rate base of $5.4 billion and an equity ratio of 56 percent.

On April 26, 2012, the CPUC approved a comprehensive multi-year settlement agreement, which covers 2012 through 2014. Key terms of the agreement include the following:

- PSCo would implement an annual electric rate increase of $73 million in 2012. The rate increase was effective on May 1, 2012. In addition, PSCo will implement incremental electric rate increases of $16 million on Jan. 1, 2013 and $25 million on Jan. 1, 2014. These rate increases are net of the shift of the costs from the purchased capacity cost adjustment and the transmission cost adjustment clauses to base rates.

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- The settlement reflects an authorized ROE of 10 percent and an equity ratio of 56 percent.
- For 2012 through 2014, incremental property taxes in excess of $76.7 million (2010-2011 historic test year property taxes) will be deferred over a three-year period with the amortization effective the first year after the deferral. To the extent that PSCo is successful in gaining the manufacturer's sales tax refund as a result of the sales tax lawsuit currently pending in the Colorado Supreme Court, PSCo will credit such refunds first against legal fees incurred to obtain the refund and then against the deferred property tax balances outstanding at the end of the 2014.
- The signing parties agreed to implement an earnings test, in which customers and shareholders will share weather normalized earnings above an ROE of 10 percent. The sharing mechanism is as follows:

ROE	Shareholders	Customers
> 10.0% < 10.2%	40 %	60 %
> 10.2% < 10.5%	50	50
> 10.5%	-	100

- PSCo agreed that it will not file for an electric rate increase that would take effect prior to Jan. 1, 2015, provided that net revenue requirements increases or decreases in excess of $10 million caused by changes in tax law, government mandates, or natural disasters may be deferred or recovered through a modified rate adjustment. In the event normalized base revenues in either 2012 or 2013 are 2.0 percent below 2011 actual levels adjusted to reflect the rate increases allowed for 2012 and 2013, PSCo has the right to an additional rate adjustment in the next year for 50 percent of the shortfall. The parties acknowledged that PSCo may file an electric rate increase as early as May 1, 2014, so long as no rate increase takes effect on either an interim or permanent basis prior to Jan. 1, 2015.

Pending and Recently Concluded Regulatory Proceedings — Federal Energy Regulatory Commission (FERC)

PSCo 2011 Wholesale Electric Rate Case — In February 2011, PSCo filed with the FERC to change Colorado wholesale electric rates to formula based rates with an expected annual increase of $16.1 million for 2011. The request was based on a 2011 forecast test year, a 10.9 percent ROE, a rate base of $407.4 million and an equity ratio of 57.1 percent. The formula rate would be estimated each year for the following year and then trued-up to actual costs after the conclusion of the calendar year. In September 2011, PSCo implemented an interim rate increase of $7.8 million, subject to refund.

In April 2012, PSCo filed an unopposed settlement agreement with wholesale customers for an annual rate increase of $7.8 million. The primary reasons for the decrease from the original request were a reduction to depreciation expense of $5.8 million and a lower ROE, ranging from 10.1 percent to 10.4 percent. The settlement was approved by the FERC in June 2012.

PSCo Transmission Formula Rate Cases — In April 2012, PSCo filed with the FERC to revise the wholesale transmission rates formula from a historic test year formula rate to a forecast transmission formula rate and to establish formula ancillary services rates. PSCo proposed that the formula rates be updated annually to reflect changes in costs, subject to a true-up. The request would increase PSCo's wholesale transmission and ancillary services revenue by approximately $2.0 million. In June 2012, the FERC issued an order accepting the proposed transmission and ancillary services formula rates, suspending the increase to Nov. 17, 2012, subject to refund, and setting the case for settlement judge or hearing procedures.

Separately, several wholesale customers filed a complaint with the FERC in June 2012 seeking to have the transmission formula rate ROE reduced from 10.25 to 9.15 percent effective July 1, 2012. It is expected that the FERC will consider both matters concurrently.

SPS Wholesale Rate Complaint — In April 2012, Golden Spread Electric Cooperative, Inc. (Golden Spread) filed a rate complaint with the FERC alleging that SPS' rates for wholesale service were excessive. Golden Spread alleges that the base ROE currently charged to them through their production formula rate, of 10.25 percent, and the transmission formula rate, of 10.77 percent, is unjust and unreasonable. Golden Spread alleges that the appropriate base ROE is 9.15 percent, or an annual difference of approximately $3.3 million. An additional 50 basis point incentive is added to the base ROE for the transmission formula rate for participation in a Regional Transmission Organization (RTO). Golden Spread is not contesting this transmission incentive. The FERC has taken no action on this complaint.

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Electric, Purchased Gas and Resource Adjustment Clauses

Renewable Energy Credit (REC) Sharing — In May 2011, the CPUC determined that margin sharing on stand-alone REC transactions would be shared 20 percent to PSCo and 80 percent to customers beginning in 2011 and ultimately becoming 10 percent to PSCo and 90 percent to customers by 2014. The CPUC also approved a change to the treatment of hybrid REC trading margins (RECs that are bundled with energy) that allows the customers' share of the margins to be netted against the renewable energy standard adjustment (RESA) regulatory asset balance. In the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

In March 2012, the CPUC approved an annual margin sharing on the first $20 million of margins on hybrid REC trades of 80 percent to the customers and 20 percent to PSCo. Margins in excess of the $20 million are to be shared 90 percent to the customers and 10 percent to PSCo. The CPUC authorized PSCo to return to customers unspent carbon offset funds by crediting the RESA regulatory asset balance. In March 2012, PSCo credited approximately $28.7 million against the RESA regulatory asset balance.

This sharing mechanism will be effective through 2014 to provide the CPUC an opportunity to review the framework and to review evidence regarding actual deliveries in relatively more complex markets such as California.

6. Commitments and Contingencies

Except to the extent noted below and in Note 5, the circumstances set forth in Notes 12, 13 and 14 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011, appropriately represent, in all material respects, the current status of commitments and contingent liabilities, including those regarding public liability for claims resulting from any nuclear incident, and are incorporated herein by reference. The following include commitments, contingencies and unresolved contingencies that are material to Xcel Energy's financial position.

Purchased Power Agreements

Under certain purchased power agreements, NSP-Minnesota, PSCo and SPS purchase power from independent power producing entities that own natural gas or biomass fueled power plants for which the utility subsidiaries are required to reimburse natural gas or biomass fuel costs, or to participate in tolling arrangements under which the utility subsidiaries procure the natural gas required to produce the energy that they purchase. These specific purchased power agreements create a variable interest in the associated independent power producing entity.

Xcel Energy had approximately 3,773 megawatts (MW) of capacity under long-term purchased power agreements as of June 30, 2012 and Dec. 31, 2011 with entities that have been determined to be variable interest entities. Xcel Energy has concluded that these entities are not required to be consolidated in its consolidated financial statements because it does not have the power to direct the activities that most significantly impact the entities' economic performance. These agreements have expiration dates through the year 2033.

Guarantees and Indemnifications

Xcel Energy Inc. and its subsidiaries provide guarantees and bond indemnities under specified agreements or transactions. The guarantees and bond indemnities issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries. As a result, Xcel Energy Inc.'s exposure under the guarantees and bond indemnities is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees and bond indemnities issued by Xcel Energy Inc. and its subsidiaries limit the exposure to a maximum amount stated in the guarantees and bond indemnities. As of June 30, 2012 and Dec. 31, 2011, Xcel Energy Inc. and its subsidiaries have no assets held as collateral related to their guarantees, bond indemnities and indemnification agreements.

The following table presents guarantees and bond indemnities issued and outstanding for Xcel Energy Inc.:

(Millions of Dollars)	June 30, 2012	Dec. 31, 2011
Guarantees issued and outstanding	$ 68.4	$ 67.5
Current exposure under these guarantees	17.9	18.0
Bonds with indemnity protection	30.0	31.2

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Indemnification Agreements

In connection with the acquisition of the 201 MW Nobles wind project in 2011, NSP-Minnesota agreed to indemnify the seller for losses arising out of a breach of certain representations and warranties. NSP-Minnesota's indemnification obligation is capped at $20 million, in the aggregate, at June 30, 2012 and Dec. 31, 2011. The indemnification obligation expires in March 2013. NSP-Minnesota has not recorded a liability related to this indemnity at June 30, 2012 or Dec. 31, 2011.

In connection with the acquisition of 900 MW of natural gas-fired generation from subsidiaries of Calpine Development Holdings Inc. in 2010, PSCo agreed to indemnify the seller for losses arising out of a breach of certain representations and warranties. The aggregate liability for PSCo pursuant to these indemnities is not subject to a capped dollar amount. The indemnification obligation expires in December 2012. PSCo has not recorded a liability related to this indemnity at June 30, 2012 or Dec. 31, 2011.

Xcel Energy Inc. and its subsidiaries provide other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, as well as breaches of representations and warranties, including due organization, transaction authorization and income tax matters with respect to assets sold. Xcel Energy Inc.'s and its subsidiaries' obligations under these agreements may be limited in terms of time and amount. The maximum potential amount of future payments under these indemnifications cannot be reasonably estimated as the obligated amounts of these indemnifications often are not explicitly stated.

Environmental Contingencies

MGP Sites

Ashland MGP Site — NSP-Wisconsin has been named a potentially responsible party (PRP) for contamination at a site in Ashland, Wis. The Ashland/Northern States Power Lakefront Superfund Site (the Ashland site) includes property owned by NSP-Wisconsin, which was a site previously operated by a predecessor company as a MGP facility (the Upper Bluff), and two other properties: an adjacent city lakeshore park area (Kreher Park), on which an unaffiliated third party previously operated a sawmill and conducted creosote treating operations; and an area of Lake Superior's Chequamegon Bay adjoining the park (the Sediments).

The U.S. Environmental Protection Agency (EPA) issued its Record of Decision (ROD) in September 2010, which documents the remedy that the EPA has selected for the cleanup of the Ashland site. In April 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, for future remediation at the site. The special notice letters requested that those PRPs participate in negotiations with the EPA regarding how the PRPs intended to conduct or pay for the remediation. As a result of those settlement negations, the EPA agreed to segment the Ashland site into separate areas. The first area (Phase I Project Area) includes soil and groundwater in Kreher Park and the Upper Bluff. The second area includes the Sediments.

In June 2012, a settlement in principle (Settlement) was reached among the EPA, the Wisconsin Department of Natural Resources (WDNR), the Bad River and Red Cliff Bands of the Lake Superior Tribe of Chippewa Indians and NSP-Wisconsin which, if it becomes effective, would resolve claims against NSP-Wisconsin for its alleged responsibility for the remediation of the Phase I Project Area. Under the terms of the proposed Settlement, NSP-Wisconsin agrees to perform the remediation of the Phase I Project Area, but does not admit any liability with respect to the Ashland site. The proposed Settlement reflects a cost estimate for the clean up of the Phase I Project Area of $40 million. The proposed Settlement also would resolve claims by the federal, state and tribal trustees against NSP-Wisconsin for alleged natural resource damages at the Ashland site, including both the Phase I Project

Area and the Sediments. As part of the proposed Settlement, NSP-Wisconsin would convey approximately 1,390 acres of land to the State of Wisconsin and tribes so that they may manage and preserve the natural resource benefits associated with those properties.

Once the proposed Settlement is executed by all parties, a consent decree reflecting this settlement will be lodged with the U.S. District Court for the Western District of Wisconsin, pending solicitation of public notice and comment. Following a 30-day public comment period, if no material adverse comments are received, the U.S. District Court would be expected to enter the consent decree as a final order, at which time it and the terms of the Settlement will become effective. While it is expected that the consent decree will be signed, there are no assurances that the consent decree will be fully executed by all parties and ultimately entered as a final order.

Negotiations between the EPA and NSP-Wisconsin regarding who will pay or perform the cleanup of the Sediments are ongoing. The EPA's ROD for the Ashland site estimates that the cost of the preferred remediation related to the Sediments is between \$63.3 million and \$77.1 million, with a potential deviation in such estimated costs of up to 50 percent higher to 30 percent lower.

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At each of June 30, 2012 and Dec. 31, 2011, NSP-Wisconsin had recorded a liability of $104.3 million for the Ashland site based upon potential remediation and design costs together with estimated outside legal and consultant costs; of which $26.6 million was considered a current liability. NSP-Wisconsin's potential liability, the actual cost of remediation and the time frame over which the amounts may be paid are subject to change until after negotiations or litigation with the EPA and other PRPs are fully resolved. NSP-Wisconsin also continues to work to identify and access state and federal funds to apply to the ultimate remediation cost of the entire site. Unresolved issues or factors that could result in higher or lower NSP-Wisconsin remediation costs for the Ashland site include, but are not limited to, the cleanup approach implemented for the Sediments, which party implements the cleanup, the timing of when the cleanup is implemented, the contributions, if any, by other PRPs and whether federal or state funding may be directed to help offset remediation costs at the Ashland site.

NSP-Wisconsin has deferred, as a regulatory asset, the estimated site remediation costs to date less insurance and rate recoveries, based on an expectation that the PSCW will continue to allow NSP-Wisconsin to recover payments for environmental remediation from its customers. The PSCW has consistently authorized in NSP-Wisconsin rates recovery of all remediation costs incurred at the Ashland site, and has authorized recovery of MGP remediation costs by other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin retail rate case process. Under an existing PSCW policy with respect to recovery of remediation costs for MGPs, utilities have recovered remediation costs in natural gas rates, amortized over a four- to six-year period. The PSCW has not allowed utilities to recover their carrying costs on unamortized regulatory assets for MGP remediation. In a recent rate case decision, the PSCW recognized the potential magnitude of the future liability for, and circumstances of, the cleanup at the Ashland site and indicated it may consider alternatives to its established MGP site cleanup cost accounting and cost recovery guidelines for the Ashland site in a future proceeding. Pursuant to the PSCW decision, NSP-Wisconsin proposed an alternative long-term plan to recover costs related to the Ashland site in the rate case application filed on June 1, 2012. As compared to the current cost recovery policy, NSP-Wisconsin's alternative proposal mitigates the rate impact to natural gas customers and allows for partial recovery of carrying costs.

NSP-Wisconsin expects a decision on the alternative cost recovery plan by the end of 2012.

Other MGP Sites — Xcel Energy is currently involved in investigating and/or remediating several other MGP sites where hazardous or other regulated materials may have been deposited. Xcel Energy has identified eight sites where former MGP activities have or may have resulted in actual site contamination and are under current investigation and/or remediation. At some or all of these MGP sites, there are other parties that may have responsibility for some portion of any ultimate remediation that may be conducted. Xcel Energy anticipates that the majority of the remediation at these sites will continue through at least 2014. For these sites, Xcel Energy had accrued $4.0 million and $3.9 million at June 30, 2012 and Dec. 31, 2011, respectively. There may be insurance recovery and/or recovery from other PRPs that will offset any costs actually incurred at these sites. Xcel Energy anticipates that any amounts actually spent will be fully recovered from customers.

Environmental Requirements

Greenhouse Gas (GHG) New Source Performance Standard Proposal (NSPS) and Emission Guideline for Existing Sources — In April 2012, the EPA proposed a GHG NSPS for newly constructed power plants. The proposal requires that carbon dioxide (CO2) emission rates be equal to those achieved by a natural gas combined-cycle plant, even if the plant is coal-fired. The EPA also proposed that NSPS not apply to modified or reconstructed existing power plants and noted that, pursuant to its general NSPS regulations, installation of control equipment on existing plants would not constitute a "modification" to those plants under the NSPS program. Xcel Energy submitted comments on the proposed GHG NSPS in June 2012. It is not possible to evaluate the impact of this regulation until its final requirements are known.

The EPA also plans to propose GHG regulations applicable to emissions from existing power plants under the Clean Air Act (CAA). It is not known when the EPA will propose new standards for existing sources.

New Mexico GHG Regulations — In 2010, the New Mexico Environmental Improvement Board (EIB) adopted two regulations to limit GHG emissions, including CO2 emissions from power plants and other industrial sources. In July 2011, SPS and other parties filed a petition to repeal each GHG rule with the EIB. The EIB repealed both regulations in the first quarter of 2012.

Western Resource Advocates and New Energy Economy, Inc. have since filed appeals with the New Mexico Court of Appeals to challenge each of the EIB's decisions to repeal the two GHG rules. SPS has been granted intervention in one of the appeals and filed a petition to intervene in the other appeal, which has not yet been acted upon by the New Mexico Court of Appeals.

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In late 2010 and early 2011, SPS, other utilities and industry groups filed separate appeals with the New Mexico Court of Appeals challenging the validity of the adoption of these two GHG regulations. These appeals were stayed pending the EIB's consideration of the petitions for repeal of both rules. In July 2012, the New Mexico Court of Appeals conditionally dismissed both appeals without prejudice. These appeals are subject to reinstatement if the New Mexico Court of Appeals reverses the EIB's repeal of either rule and if the originally adopted rule is revived.

Cross-State Air Pollution Rule (CSAPR) — In July 2011, the EPA issued its CSAPR to address long range transport of particulate matter (PM) and ozone by requiring reductions in sulfur dioxide (SO2) and nitrogen oxide (NOx) from utilities located in the eastern half of the United States. For Xcel Energy, the rule applies to Minnesota, Wisconsin and Texas. The CSAPR sets more stringent requirements than the proposed Clean Air Transport Rule and specifically requires plants in Texas to reduce their SO2 and annual NOx emissions. The rule also creates an emissions trading program.

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a stay of the CSAPR, pending completion of judicial review. Oral arguments in the case were held in April 2012 and it is anticipated the D.C. Circuit will rule on the challenges to the CSAPR during the summer of 2012. It is not known at this time whether the CSAPR will be upheld, reversed or will require modifications pursuant to a future D.C. Circuit decision.

If the CSAPR is upheld and unmodified, Xcel Energy believes that the CSAPR could ultimately require the installation of additional emission controls on some of SPS' coal-fired electric generating units. If compliance is required in a short time frame, SPS may be required to redispatch its system to reduce coal plant operating hours in order to decrease emissions from its facilities prior to the installation of emission controls. The expected cost for these scenarios may vary significantly and SPS has estimated capital expenditures of approximately $470 million over the next five years for the plant modifications related to the CSAPR requirements. SPS believes the cost of any required capital investment or possible increased fuel costs would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position or cash flows. In April 2012, SPS appealed to the D.C. Circuit on a final rule that the EPA issued that made changes to certain allowance allocations under the CSAPR. While this rule increases the allowance allocations for SO2 for SPS, it did not increase them by as much as the proposed rule. SPS is seeking additional allowance allocations through this appeal, which, if successful, would reduce SPS' costs to comply with the CSAPR. The D.C. Circuit held this appeal in abeyance until it issues its decision.

If the CSAPR is upheld and unmodified, NSP-Minnesota would likely utilize a combination of emissions reductions through upgrades to its existing SO2 control technology at Sherco Units 1 and 2, which is estimated to cost a total of $10 million through 2014, and system operating changes to Black Dog and Sherco Units 1 and 2. Costs for the Sherco Units 1 and 2 SO2 control technology are discussed below in the regional haze rules as SO2 reductions are part of the compliance plan for both the CSAPR and the regional haze rules. If available, NSP-Minnesota would also consider allowance purchases. In addition, NSP-Minnesota has filed a petition for reconsideration with the EPA and a petition for review of the CSAPR with the D.C. Circuit seeking the allocation of additional emission allowances to NSP-Minnesota. NSP-Minnesota contends that the EPA's method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to their conversion to natural gas. In April 2012, NSP-Minnesota appealed to the D.C. Circuit on a final rule that the EPA issued that made changes to certain allowance allocations under the CSAPR, seeking to secure additional allocations for its Riverside and High Bridge plants. If successful, additional allowances would reduce NSP-Minnesota's costs to comply with the CSAPR. The D.C. Circuit held this appeal in abeyance until it issues its decision.

If the CSAPR is upheld and unmodified, NSP-Wisconsin would likely make a combination of system operating changes and allowance purchases. NSP-Wisconsin estimates the cost of compliance would be $0.2 million, and expects the cost of any required capital investment will be recoverable from customers.

Electric Generating Unit (EGU) Mercury and Air Toxics Standards (MATS) Rule — The final EGU MATS rule became effective April 2012. The EGU MATS rule sets emission limits for acid gases, mercury and other hazardous air pollutants and requires coal-fired utility facilities greater than 25 MW to demonstrate compliance within three to four years of the effective date. Xcel Energy believes these costs will be recoverable through regulatory mechanisms and does not expect a material impact on results of operations, financial position or cash flows.

Regional Haze Rules — In 2005, the EPA finalized amendments to its regional haze rules regarding provisions that require the installation and operation of emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility in certain national parks and wilderness areas throughout the United States. Xcel Energy generating facilities in several states are subject to BART requirements. Individual states were required to identify the facilities located in their states that will have to reduce SO_2, NO_x and PM emissions under BART and then set emissions limits for those facilities.

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PSCo

In 2006, the Colorado Air Quality Control Commission (CAQCC) promulgated BART regulations requiring certain major stationary sources to evaluate, install, operate and maintain BART to make reasonable progress toward meeting the national visibility goal. In January 2011, the CAQCC approved a revised regional haze BART state implementation plan (SIP) incorporating the Colorado CACJA emission reduction plan, which will satisfy regional haze requirements. In March 2012, the EPA proposed to approve the Colorado SIP, including the CACJA emission reduction plan for PSCo, as satisfying BART requirements. The emission controls are expected to be installed between late 2012 and 2017. PSCo expects the cost of any required capital investment will be recoverable from customers through the CACJA emission reduction plan recovery mechanisms or other regulatory mechanisms.

In March 2010, two environmental groups petitioned the U.S. Department of the Interior (DOI) to certify that 12 coal-fired boilers and one coal-fired cement kiln in Colorado are contributing to visibility problems in Rocky Mountain National Park. The following PSCo plants are named in the petition: Cherokee, Hayden, Pawnee and Valmont. The groups allege that the Colorado BART rule is inadequate to satisfy the CAA mandate of ensuring reasonable further progress towards restoring natural visibility conditions in the park. It is not known when the DOI will rule on the petition.

NSP-Minnesota

In December 2009, the Minnesota Pollution Control Agency (MPCA) approved the regional haze SIP, which has been submitted to the EPA for approval. The MPCA selected the BART controls for Sherco Units 1 and 2 to improve visibility in the national parks. The MPCA concluded Selective Catalytic Reduction (SCR) should not be required because the minor visibility benefits derived from SCRs do not outweigh the substantial costs. The MPCA’s BART controls for Sherco Units 1 and 2 consist of combustion controls for NOx and scrubber upgrades for SO2. The combustion controls have been installed on Sherco Units 1 and 2, and the scrubber upgrades are scheduled to be installed by 2015. At this time, the estimated cost for meeting the BART, regional haze and other CAA requirements is approximately $50 million, of which $20 million has already been spent on projects to reduce NOx emissions on Sherco Units 1 and 2. Xcel Energy anticipates that all costs associated with BART compliance will be fully recoverable through regulatory recovery mechanisms.

In June 2011, the EPA provided comments to the MPCA on the SIP, stating that the EPA’s preliminary review indicates that SCR controls should be added to Sherco Units 1 and 2. The MPCA has since proposed that the CSAPR should be considered BART for EGUs and the EPA proposed that states be allowed to find that CSAPR compliance meets BART requirements for EGUs, and specifically that Minnesota’s proposal to find the CSAPR to meet BART requirements should be approved, if finalized by the state.

In April 2012, the MPCA approved a supplement to the 2009 regional haze SIP finding that the CSAPR meets BART for EGUs in Minnesota. The supplement also made a source-specific BART determination for Sherco Units 1 and 2 that requires installation of the combustion controls for NOx and scrubber upgrades for SO2 by January 2015. In May 2012, the EPA adopted a final rule that allows states to determine whether CSAPR compliance meets BART requirements. In June 2012, the EPA issued its final approval of the Minnesota SIP for EGUs.

In addition to the regional haze rules identified in the EPA’s visibility program, and addressed in the MPCA’s SIP discussed above, there are other visibility rules related to a program called the Reasonably Attributable Visibility Impairment (RAVI) program. In October 2009, the DOI certified that a portion of the visibility impairment in Voyageurs and Isle Royale National Parks is reasonably attributable to emissions from NSP-Minnesota’s Sherco Units 1 and 2. The EPA is required to make its own determination as to whether Sherco Units 1 and 2 cause or contribute to RAVI and, if so, whether the level of controls required by the MPCA is appropriate. The EPA plans to issue a separate notice on the issue of BART for Sherco Units 1 and 2 under the RAVI program. It is not yet known when the EPA will publish a proposal under RAVI, or what that proposal will entail. In May 2012, a notice of intent to sue was filed with the EPA by the following organizations: National Parks Conservation Association, Minnesota Center for Environmental Advocacy, Friends of the Boundary Waters Wilderness, Voyagers National Park Association, Fresh Energy and Sierra Club. The notice advised the EPA of the parties' intent to sue the EPA in 180 days to attempt to require the EPA to determine BART for the Sherco Units 1 and 2 under the RAVI program. It is not yet known how the EPA intends to respond to this notice.

SPS

Harrington Units 1 and 2 are potentially subject to BART. Texas has developed a regional haze SIP that finds the Clean Air Interstate Rule (CAIR) equal to BART for EGUs, and as a result, no additional controls for these units beyond the CAIR compliance would be required. In May 2012, the EPA deferred its review of the Texas SIP in its final rule allowing states to find that CSAPR compliance meets BART requirements for EGUs.

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Revisions to National Ambient Air Quality Standards (NAAQS) for PM — In June 2012, the EPA proposed to lower the primary (health-based) NAAQS for annual average fine PM and to retain the current daily standard for fine PM. In areas in which Xcel Energy operates power plants, current monitored air concentrations are below the range of the proposed annual primary standard. The EPA also proposed to add a secondary (welfare-based) NAAQS to improve visibility, primarily in urban areas. Xcel Energy expects the proposed visibility standard would likely be met where Xcel Energy operates power plants based on currently available information. A final rule is expected in December 2012 and the EPA is expected to designate non-compliant locations by December 2014. If such areas are identified, states would then study the sources of the nonattainment and make emission reduction plans to attain the standards. It is not possible to evaluate the impact of this regulation further until its final requirements are known.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material effect on Xcel Energy's consolidated financial position, results of operations, and cash flows.

Environmental Litigation

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other utility, oil, gas and coal companies. Plaintiffs claim that defendants' emission of CO2 and other GHGs contribute to global warming, which is harming their village. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss in June 2008. In October 2009, the U.S. District Court dismissed the lawsuit on constitutional grounds. In November 2009, plaintiffs filed a notice of appeal to the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit). In November 2011, oral arguments were presented. It is unknown when the Ninth Circuit will render a final opinion. The amount of damages claimed by plaintiffs is unknown, but likely includes the cost of relocating the village of Kivalina. Plaintiffs' alleged relocation is estimated to cost between $95 million to $400 million. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

Comer vs. Xcel Energy Inc. et al. — In May 2011, less than a year after their initial lawsuit was dismissed, plaintiffs in this purported class action lawsuit filed a second lawsuit against more than 85 utility, oil, chemical and coal companies in U.S. District Court in Mississippi. The complaint alleges defendants' CO2 emissions intensified the strength of Hurricane Katrina and increased the damage plaintiffs purportedly sustained to their property. Plaintiffs base their claims on public and private nuisance, trespass and negligence. Among the defendants named in the complaint are Xcel Energy Inc., SPS, PSCo, NSP-Wisconsin and NSP-Minnesota. The amount of damages claimed by plaintiffs is unknown. The defendants, including Xcel Energy Inc., believe this lawsuit is without merit and filed a motion to dismiss the lawsuit. In March 2012, the U.S. District Court granted this motion for dismissal. In April 2012, plaintiffs appealed this decision to the U.S. Court of Appeals for the Fifth Circuit. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

Employment, Tort and Commercial Litigation

Merricourt Wind Project Litigation — In April 2011, NSP-Minnesota terminated its agreements with enXco Development Corporation (enXco) for the development of a 150 MW wind project in southeastern North Dakota. NSP-Minnesota's decision to terminate the agreements was based in large part on the adverse impact this project could have on endangered or threatened species protected by federal law and the uncertainty in cost and timing in mitigating this impact. NSP-Minnesota also terminated the agreements due to enXco's nonperformance of certain other conditions, including failure to obtain a Certificate of Site Compatibility and the failure to close on the contracts by an agreed upon date of March 31, 2011. NSP-Minnesota recorded a $101 million deposit in the first quarter of 2011, which was collected in April 2011. In May 2011, NSP-Minnesota filed a declaratory judgment action in U.S. District Court in Minnesota to obtain a determination that it acted properly in terminating the agreements and enXco also filed a separate lawsuit in the same court seeking, among other things, in excess of $240 million for an alleged breach of contract. NSP-Minnesota believes enXco's lawsuit is without merit and filed a motion to dismiss. In September 2011, the U.S. District Court denied the motion to dismiss. The trial is set to begin in late 2012 or early 2013. While Xcel Energy believes the likelihood of loss is remote, given the nature of this case and any surrounding uncertainty, it could potentially have a material impact on Xcel Energy's consolidated results of operations, cash flows or financial position. No accrual has been recorded for this matter.

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Exelon Wind (formerly John Deere Wind) Complaint — Four lawsuits and a regulatory petition have been filed arising out of a dispute concerning SPS' payments for energy produced from the John Deere Wind Energy subsidiaries' (JD Wind) projects.

State Lawsuit Regarding the PUCT's May 2009 Order
The first lawsuit was filed in June 2009 in Texas State District Court against the Public Utility Commission of Texas (PUCT). In this lawsuit, JD Wind filed a petition seeking review of a May 2009 PUCT order denying JD Wind's request for relief against SPS. In April 2011, JD Wind filed a non-suit of this case dropping the state appeal of the PUCT order.

Federal Lawsuit Regarding the PUCT's May 2009 Order
A second lawsuit was filed in December 2009 by JD Wind against the PUCT in U.S. District Court for the Western District of Texas. This lawsuit was filed shortly after a declaratory order issued by the FERC stated that the PUCT's May 2009 order is not consistent with the FERC's regulations. In this lawsuit, JD Wind seeks declaratory and injunctive relief against the PUCT. The U.S. District Court issued an order preventing this lawsuit from proceeding pending the outcome of the Texas State District Court proceeding against the PUCT. As a result of the non-suit of the Texas State District Court proceeding, this case has moved forward. In March and June 2012, the U.S. District Court heard oral arguments on motions and cross motions for summary judgment, and took the motions under advisement. If the U.S. District Court does not grant one of these dispositive motions, the case will proceed with a trial date in October 2013 at the earliest.

State Lawsuit Regarding Disputed Energy Payments
In January 2010, a third lawsuit was filed by JD Wind against SPS in Texas State District Court related to payments made by SPS for energy produced from the JD Wind projects. On April 12, 2012, the Texas State District Court heard oral arguments on SPS' motion to dismiss and took the motion under advisement. As the damages sought are indeterminate and given the uncertainty surrounding the circumstances of this case, Xcel Energy is unable to estimate the range or amount of possible damages. No accrual has been recorded for this lawsuit nor is it expected that this proceeding will have a material effect on Xcel Energy's consolidated results of operations, cash flows or financial position.

Petition Regarding the PUCT's Approval of SPS' Revised Qualifying Facilities Tariff
In November 2010, JD Wind filed a petition in Texas State District Court seeking review of the PUCT's approval of SPS' revised tariff applicable to purchases of non-firm energy from qualifying facilities. The PUCT has denied all allegations contained in this petition. A hearing is scheduled for Sept. 6, 2012. On June 29, 2012, Exelon Wind filed a complaint with the FERC against the PUCT raising essentially the same alleged violations of federal law as those presented in the petition filed in November 2010. On July 30, 2012, the PUCT filed an answer to this complaint defending its order and SPS filed an intervention and protest in support of the PUCT's order.

State Lawsuit Regarding Wind Facility Registration with Southwest Power Pool (SPP)
On April 3, 2012, SPS filed a lawsuit against Exelon Wind in Texas State District Court to enforce Exelon Wind's contractual obligation to register its wind facilities with SPP effective April 1, 2012. SPS is not seeking monetary damages in this lawsuit. Instead, SPS intends to withhold certain payments to Exelon Wind pending the outcome of this lawsuit. On May 7, 2012, Exelon Wind filed a counter-claim seeking recovery of the payments withheld by SPS. A procedural schedule has not yet been established. For the period April 1, 2012 to June 20, 2012, Xcel Energy has accrued approximately $2 million, which is subject to adjustments as the amount, if any, owed to Exelon Wind will be a litigated issue in this lawsuit. This lawsuit is not expected to have a material effect on Xcel Energy's consolidated results of operations, cash flows or financial position.

Registration Agreement Filed by SPP with the FERC

On June 21, 2012, the FERC conditionally accepted SPP's filing of an unsigned Market Participation Agreement between SPP and Exelon covering Exelon's wind facilities.

7. Borrowings and Other Financing Instruments

Money Pool — Xcel Energy Inc. and its utility subsidiaries have established a money pool arrangement that allows for short-term investments in and borrowings between the utility subsidiaries. NSP-Wisconsin does not participate in the money pool. 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 upon consolidation.

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Commercial Paper — Xcel Energy Inc. and its utility subsidiaries meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings under their credit facilities. Commercial paper outstanding for Xcel Energy was as follows:

(Millions of Dollars, Except Interest Rates)	Three Months Ended June 30, 2012	Twelve Months Ended Dec. 31, 2011
Borrowing limit	$ 2,450	$ 2,450
Amount outstanding at period end	481	219
Average amount outstanding	456	430
Maximum amount outstanding	634	824
Weighted average interest rate, computed on a daily basis	0.37%	0.36%
Weighted average interest rate at period end	0.35	0.40

Credit Facilities — In order to use their commercial paper programs to fulfill short-term funding needs, Xcel Energy Inc. and its utility subsidiaries must have revolving credit facilities in place at least equal to the amount of their respective commercial paper borrowing limits and cannot issue commercial paper in an aggregate amount exceeding available capacity under these credit agreements. The lines of credit provide short-term financing in the form of notes payable to banks, letters of credit and back-up support for commercial paper borrowings.

At June 30, 2012, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available:

(Millions of Dollars)	Credit Facility	Drawn (a)	Available
Xcel Energy Inc.	$ 800.0	$ 397.0	$ 403.0
PSCo	700.0	8.0	692.0
NSP-Minnesota	500.0	8.7	491.3
SPS	300.0	-	300.0
NSP-Wisconsin	150.0	79.0	71.0
Total	$ 2,450.0	$ 492.7	$ 1,957.3

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

All credit facility bank borrowings, outstanding letters of credit and outstanding commercial paper reduce the available capacity under the respective credit facilities. Xcel Energy Inc. and its subsidiaries had no direct advances on the credit facilities outstanding at June 30, 2012 and Dec. 31, 2011.

Amended Credit Agreements — In July 2012, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. entered into amended five-year credit agreements with a syndicate of banks, replacing their previous four-year credit agreements. The amended credit agreements have substantially the same terms and conditions as the prior credit agreements with an improvement in pricing and an extension of maturity from March 2015 to July 2017. The Eurodollar borrowing margins on these lines of credit were reduced from a range of 100 to 200 basis points per year, to a range of 87.5 to 175 basis points per year based on applicable long-term credit ratings. The commitment fees, calculated on the unused portion of the lines of credit, were reduced from a range of 10 to 35 basis points per year, to a range of 7.5 to 27.5 basis points per year, also based on applicable long-term credit ratings.

Xcel Energy Inc. and its utility subsidiaries, other than NSP-Wisconsin, have the right to request an extension of the revolving termination date for two additional one-year periods, and NSP-Wisconsin has the right to request an extension of the revolving termination date for an additional one-year period, each subject to majority bank group approval.

Letters of Credit — Xcel Energy Inc. and its subsidiaries use letters of credit, generally with terms of one year, to provide financial guarantees for certain operating obligations. At June 30, 2012 and Dec. 31, 2011, there were $11.7 million and $12.7 million of letters of credit outstanding, respectively, under the credit facilities. An additional $1.1 million of letters of credit not issued under the credit facilities were outstanding at June 30, 2012 and Dec. 31, 2011, respectively. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

Long-Term Borrowings

In June 2012, SPS issued an additional $100 million of its 4.5 percent first mortgage bonds due Aug. 15, 2041 at a premium of $10.1 million. Including the $200 million of this series previously issued in August 2011, total principal outstanding for this series is $300 million.

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8. Fair Value of Financial Assets and Liabilities

Fair Value Measurements

The accounting guidance for fair value measurements and disclosures provides a single definition of fair value and requires certain disclosures about assets and liabilities measured at fair value. A hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value is established by this guidance. The three levels in the hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reporting date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, or priced with discounted cash flow or option pricing models using highly observable inputs.

Level 3 — Significant inputs to pricing have little or no observability as of the reporting date. The types of assets and liabilities included in Level 3 are those valued with models requiring significant management judgment or estimation.

Specific valuation methods include the following:

Cash equivalents — The fair values of cash equivalents are generally based on cost plus accrued interest; money market funds are measured using quoted net asset values.

Investments in equity securities and other funds — Equity securities are valued using quoted prices in active markets. The fair values for commingled funds, international equity funds, private equity investments and real estate investments are measured using net asset values, which take into consideration the value of underlying fund investments, as well as the other accrued assets and liabilities of a fund, in order to determine a per share market value. The investments in commingled funds and international equity funds may be redeemed for net asset value with proper notice. Private equity investments require approval of the fund for any unscheduled redemption, and such redemptions may be approved or denied by the fund at its sole discretion. Unscheduled distributions from real estate investments may be redeemed with proper notice; however, withdrawals from real estate investments may be delayed or discounted as a result of fund illiquidity. Based on Xcel Energy's evaluation of its ability to redeem private equity and real estate investments, fair value measurements for private equity and real estate investments have been assigned a Level 3.

Investments in debt securities — Fair values for debt securities are determined by a third party pricing service using recent trades and observable spreads from benchmark interest rates for similar securities, except for asset-backed and mortgage-backed securities, for which the third party service may also consider additional, more subjective inputs. Since the impact of the use of these less observable inputs can be significant to the valuation of asset-backed and mortgage-backed securities, fair value measurements for these instruments have been assigned a Level 3. Inputs that may be considered in the valuation of asset-backed and mortgage-backed securities in conjunction with pricing of similar securities in active markets include the use of risk-based discounting and estimated prepayments in a discounted cash flow model. When these additional inputs and models are utilized, increases in the risk-adjusted discount rates and decreases in the assumed principal prepayment rates each have the impact of reducing reported fair values for these instruments.

Interest rate derivatives — The fair values of interest rate derivatives are based on broker quotes that utilize current market interest rate forecasts.

Commodity derivatives — The methods used to measure the fair value of commodity derivative forwards and options utilize forward prices and volatilities, as well as pricing adjustments for specific delivery locations, and are generally assigned a Level 2. When contractual settlements extend to periods beyond those readily observable on active exchanges or quoted by brokers, the significance of the use of less observable forecasts of long-term forward prices and volatilities on a valuation is evaluated, and may result in Level 3 classification.

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Electric commodity derivatives held by NSP-Minnesota include financial transmission rights (FTRs) purchased from Midwest Independent Transmission System Operator, Inc. (MISO). FTRs purchased from MISO are financial instruments that entitle the holder to one year of monthly revenues or charges based on transmission congestion across a given transmission path. The value of an FTR is derived from, and designed to offset, the cost of that energy congestion, which is caused by overall transmission load and other transmission constraints. Congestion is also influenced by the operating schedules of power plants and the consumption of electricity pertinent to a given transmission path. Unplanned plant outages, scheduled plant maintenance, changes in the relative costs of fuels used in generation, weather and overall changes in demand for electricity can each impact the operating schedules of the power plants on the transmission grid and the value of an FTR. NSP-Minnesota's valuation process for FTRs utilizes complex iterative modeling to predict the impacts of forecasted changes in these drivers of transmission system congestion on the historical pricing of FTR purchases.

If forecasted costs of electric transmission congestion increase or decrease for a given FTR path, the value of that particular FTR instrument will likewise increase or decrease. Given the limited observability of management's forecasts for several of the inputs to this complex valuation model – including expected plant operating schedules and retail and wholesale demand, fair value measurements for FTRs have been assigned a Level 3. Monthly FTR settlements are included in the fuel clause adjustment, and therefore changes in the fair value of the yet to be settled portions of FTRs are deferred as a regulatory asset or liability. Given this regulatory treatment and the limited magnitude of NSP-Minnesota's FTRs relative to its electric utility operations, the numerous unobservable quantitative inputs to the complex model used for valuation of FTRs are insignificant to the consolidated financial statements of Xcel Energy.

Xcel Energy continuously monitors the creditworthiness of the counterparties to its interest rate derivatives and commodity derivatives, and assesses each counterparty's ability to perform on the transactions set forth in the contracts. Given this assessment, as well as an assessment of the impact of Xcel Energy's own credit risk when determining the fair value of derivative liabilities, the impact of considering credit risk was immaterial to the fair value of interest rate derivatives and commodity derivatives presented in the consolidated balance sheets.

Non-Derivative Instruments Fair Value Measurements

The Nuclear Regulatory Commission (NRC) requires NSP-Minnesota to maintain a portfolio of investments to fund the costs of decommissioning its nuclear generating plants. Together with all accumulated earnings or losses, the assets of the nuclear decommissioning fund are legally restricted for the purpose of decommissioning the Monticello and Prairie Island nuclear generating plants. The fund contains cash equivalents, debt securities, equity securities and other investments – all classified as available-for-sale. NSP-Minnesota plans to reinvest matured securities until decommissioning begins.

NSP-Minnesota recognizes the costs of funding the decommissioning of its nuclear generating plants over the lives of the plants, assuming rate recovery of all costs. 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.

Unrealized gains for the decommissioning fund were $109.8 million and $79.8 million at June 30, 2012 and Dec. 31, 2011, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $76.6 million and $87.5 million at June 30, 2012 and Dec. 31, 2011, respectively.

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The following tables present the cost and fair value of Xcel Energy's non-derivative instruments with recurring fair value measurements in the nuclear decommissioning fund at June 30, 2012 and Dec. 31, 2011:

		June 30, 2012 Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$24,913	$15,082	$9,831	$-	$24,913
Commingled funds	375,222	-	372,487	-	372,487
International equity funds	65,712	-	62,469	-	62,469
Private equity investments	22,593	-	-	23,303	23,303
Real estate	28,536	-	-	32,721	32,721
Debt securities:					
Government securities	118,378	-	119,376	-	119,376
U.S. corporate bonds	151,444	-	159,834	-	159,834
International corporate bonds	22,782	-	23,709	-	23,709
Municipal bonds	66,769	-	70,608	-	70,608
Asset-backed securities	7,057	-	-	7,068	7,068
Mortgage-backed securities	63,526	-	-	66,321	66,321
Equity securities:					
Common stock	407,384	424,703	-	-	424,703
Total	$1,354,316	$439,785	$818,314	$129,413	$1,387,512

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $100.3 million of equity investments in unconsolidated subsidiaries and $34.4 million of miscellaneous investments.

		Dec. 31, 2011 Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$26,123	$7,103	$19,020	$-	$26,123
Commingled funds	320,798	-	311,105	-	311,105
International equity funds	63,781	-	58,508	-	58,508
Private equity investments	9,203	-	-	9,203	9,203
Real estate	24,768	-	-	26,395	26,395
Debt securities:					
Government securities	116,490	-	117,256	-	117,256
U.S. corporate bonds	187,083	-	193,516	-	193,516
International corporate bonds	35,198	-	35,804	-	35,804
Municipal bonds	60,469	-	64,731	-	64,731
Asset-backed securities	16,516	-	-	16,501	16,501
Mortgage-backed securities	75,627	-	-	78,664	78,664
Equity securities:					
Common stock	408,122	398,625	-	-	398,625
Total	$1,344,178	$405,728	$799,940	$130,763	$1,336,431

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $92.7 million of equity investments in unconsolidated subsidiaries and $34.3 million of miscellaneous investments.

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The following tables present the changes in Level 3 nuclear decommissioning fund investments for the three and six months ended June 30, 2012 and 2011:

(Thousands of Dollars)	April 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	June 30, 2012
Private equity investments	$ 20,068	$ 3,235	$ -	$ -	$ 23,303
Real estate	27,905	2,271	-	2,545	32,721
Asset-backed securities	16,547	-	(9,458)	(21)	7,068
Mortgage-backed securities	68,671	7,414	(9,690)	(74)	66,321
Total	$ 133,191	$ 12,920	$ (19,148)	$ 2,450	$ 129,413

(Thousands of Dollars)	April 1, 2011	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	June 30, 2011
Asset-backed securities	$ 26,020	$ -	$ (5,206)	$ 190	$ 21,004
Mortgage-backed securities	98,367	52,952	(88,584)	(464)	62,271
Total	$ 124,387	$ 52,952	$ (93,790)	$ (274)	$ 83,275

(Thousands of Dollars)	Jan. 1, 2012	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	June 30, 2012
Private equity investments	$ 9,203	$ 13,390	$ -	$ 710	$ 23,303
Real estate	26,395	3,907	(1,766)	4,185	32,721
Asset-backed securities	16,501	-	(9,459)	26	7,068
Mortgage-backed securities	78,664	14,318	(26,418)	(243)	66,321
Total	$ 130,763	$ 31,615	$ (37,643)	$ 4,678	$ 129,413

(Thousands of Dollars)	Jan. 1, 2011	Purchases	Settlements	Gains (Losses) Recognized as Regulatory Assets and Liabilities	June 30, 2011
Asset-backed securities	$ 33,174	$ 756	$ (13,116)	$ 190	$ 21,004
Mortgage-backed securities	72,589	99,065	(108,457)	(926)	62,271
Total	$ 105,763	$ 99,821	$ (121,573)	$ (736)	$ 83,275

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class at June 30, 2012:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total

	or Less				
Government securities	$104,694	$ 79	$ 3,648	$ 10,955	$119,376
U.S. corporate bonds	-	40,032	103,834	15,968	159,834
International corporate bonds	-	6,481	17,228	-	23,709
Municipal bonds	-	-	27,692	42,916	70,608
Asset-backed securities	-	4,983	2,085	-	7,068
Mortgage-backed securities	-	-	877	65,444	66,321
Debt securities	$104,694	$ 51,575	$ 155,364	$ 135,283	$446,916

Derivative Instruments Fair Value Measurements

Xcel Energy enters into derivative instruments, including forward contracts, futures, swaps and options, for trading purposes and to reduce risk in connection with changes in interest rates, utility commodity prices and vehicle fuel prices, as well as variances in forecasted weather.

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Interest Rate Derivatives — Xcel Energy enters into various instruments that effectively fix the interest payments on certain floating rate debt obligations or effectively fix the yield or price on a specified benchmark interest rate for an anticipated debt issuance for a specific period. These derivative instruments are generally designated as cash flow hedges for accounting purposes.

At June 30, 2012, accumulated other comprehensive losses related to interest rate derivatives included $0.9 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

At June 30, 2012, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million. These interest rate swaps were designated as hedges, and as such, changes in fair value are recorded to OCI.

Short-Term Wholesale and Commodity Trading Risk — Xcel Energy conducts various short-term 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.

Commodity Derivatives — Xcel Energy enters into derivative instruments to manage variability of future cash flows from changes in commodity prices in its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At June 30, 2012, Xcel Energy had various vehicle fuel related contracts designated as cash flow hedges extending through December 2014. Xcel Energy also enters into derivative instruments that mitigate commodity price risk on behalf of electric and natural gas customers but are not designated as qualifying hedging transactions. Changes in the fair value of non-trading commodity derivative instruments are recorded in OCI or deferred as a regulatory asset or liability. The classification as a regulatory asset or liability is based on commission approved regulatory recovery mechanisms. Xcel Energy recorded immaterial amounts to income related to the ineffectiveness of cash flow hedges for the three and six months ended June 30, 2012 and 2011.

At June 30, 2012, accumulated OCI related to commodity derivative cash flow hedges included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenues, net of amounts credited to customers under margin-sharing mechanisms.

The following table details the gross notional amounts of commodity forwards, options and FTRs at June 30, 2012 and Dec. 31, 2011:

(Amounts in Thousands) (a)(b)	June 30, 2012	Dec. 31, 2011
Megawatt hours (MWh) of electricity	61,499	38,822
MMBtu of natural gas	8,252	40,736
Gallons of vehicle fuel	500	600

(a) Amounts are not reflective of net positions in the underlying commodities.
(b) Notional amounts for options are included on a gross basis, but are weighted for the probability of exercise.

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The following tables detail the impact of derivative activity during the three and six months ended June 30, 2012 and June 30, 2011, on OCI, regulatory assets and liabilities, and income:

	Three Months Ended June 30, 2012				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (58,695)	$ -	$ 389 (a)	$ -	$ -
Vehicle fuel and other commodity	(196)	-	(49)(e)	-	-
Total	$ (58,891)	$ -	$ 340	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 1,589 (b)
Electric commodity	-	38,174	-	(9,713)(c)	-
Natural gas commodity	-	885	-	-	-
Total	$ -	$ 39,059	$ -	$ (9,713)	$ 1,589

	Six Months Ended June 30, 2012				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains (Losses) Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (16,991)	$ -	$ 777 (a)	$ -	$ -
Vehicle fuel and other commodity	(17)	-	(100)(e)	-	-
Total	$ (17,008)	$ -	$ 677	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 3,312 (b)
Electric commodity	-	39,756	-	(17,685)(c)	-
Natural gas commodity	-	(9,898)	-	80,939 (d)	(109)(b)
Total	$ -	$ 29,858	$ -	$ 63,254	$ 3,203

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	Three Months Ended June 30, 2011				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ -	$ -	$ 340 (a)	$ -	$ -
Vehicle fuel and other commodity	(78)	-	(52)(e)	-	-
Total	$ (78)	$ -	$ 288	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 1,170 (b)
Electric commodity	-	10,299	-	(8,666)(c)	-
Natural gas commodity	-	(9,564)	-	738 (d)	-
Total	$ -	$ 735	$ -	$ (7,928)	$ 1,170

	Six Months Ended June 30, 2011				
	Fair Value Gains (Losses) Recognized During the Period in:		Pre-Tax (Gains) Losses Reclassified into Income During the Period from:		
(Thousands of Dollars)	Accumulated Other Comprehensive Loss	Regulatory (Assets) and Liabilities	Accumulated Other Comprehensive Loss	Regulatory Assets and (Liabilities)	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ -	$ -	$ 677 (a)	$ -	$ -
Vehicle fuel and other commodity	311	-	(84)(e)	-	-
Total	$ 311	$ -	$ 593	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 6,770 (b)
Electric commodity	-	19,145	-	(17,554)(c)	-
Natural gas commodity	-	(17,179)	-	58,125 (d)	-
Total	$ -	$ 1,966	$ -	$ 40,571	$ 6,770

(a) Recorded to interest charges.

(b) Recorded to electric operating revenues. Portions of these gains and losses are subject to sharing with electric customers through margin-sharing mechanisms and deducted from gross revenue, as appropriate.

(c)Recorded to electric fuel and purchased power. These derivative settlement gains and losses are shared with electric customers through fuel and purchased energy cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(d)Recorded to cost of natural gas sold and transported. These derivative settlement gains and losses are shared with natural gas customers through purchased natural gas cost-recovery mechanisms, and reclassified out of income as regulatory assets or liabilities, as appropriate.

(e)Recorded to operating and maintenance (O&M) expenses.

Xcel Energy had no derivative instruments designated as fair value hedges during the three and six months ended June 30, 2012 and June 30, 2011. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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Credit Related Contingent Features — Contract provisions of the derivative instruments that the utility subsidiaries enter into may require the posting of collateral or settlement of the contracts for various reasons, including if the applicable utility subsidiary is unable to maintain its credit ratings. If the credit ratings of Xcel Energy Inc.'s utility subsidiaries were downgraded below investment grade, contracts underlying $26.8 million and $8.3 million of derivative instruments in a gross liability position at June 30, 2012 and Dec. 31, 2011, respectively, would have required Xcel Energy Inc.'s utility subsidiaries to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $8.8 million and $9.3 million, respectively. At June 30, 2012 and Dec. 31, 2011, there was no collateral posted on these specific contracts.

Certain derivative instruments are also subject to contract provisions that contain adequate assurance clauses. These provisions allow counterparties to seek performance assurance, including cash collateral, in the event that a given utility subsidiary's ability to fulfill its contractual obligations is reasonably expected to be impaired. Xcel Energy had no collateral posted related to adequate assurance clauses in derivative contracts as of June 30, 2012 and Dec. 31, 2011.

Recurring Fair Value Measurements — The following tables present for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at June 30, 2012:

	June 30, 2012					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$89	$-	$89	$ -	$89
Other derivative instruments:						
Trading commodity	79	31,891	-	31,970	(11,065)	20,905
Electric commodity	-	-	35,664	35,664	(1,875)	33,789
Natural gas commodity	-	924	-	924	(56)	868
Total current derivative assets	$79	$32,904	$35,664	$68,647	$ (12,996)	55,651
Purchased power agreements (a)						32,717
Current derivative instruments						$88,368
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$57	$-	$57	$ (31)	$26
Other derivative instruments:						
Trading commodity	-	36,106	-	36,106	(4,538)	31,568
Total noncurrent derivative assets	$-	$36,163	$-	$36,163	$ (4,569)	31,594
Purchased power agreements (a)						105,421
Noncurrent derivative instruments						$137,015

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	June 30, 2012					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$-	$74,740	$-	$74,740	$ -	$74,740
Other derivative instruments:						
Trading commodity	112	25,877	-	25,989	(11,773)	14,216
Electric commodity	-	-	1,875	1,875	(1,875)	-
Natural gas commodity	-	38	-	38	(38)	-
Total current derivative liabilities	$112	$100,655	$1,875	$102,642	$ (13,686)	88,956
Purchased power agreements (a)						22,880
Current derivative instruments						$111,836
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$20,834	$-	$20,834	$ (4,570)	$16,264
Total noncurrent derivative liabilities	$-	$20,834	$-	$20,834	$ (4,570)	16,264
Purchased power agreements (a)						237,100
Noncurrent derivative instruments						$253,364

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) The accounting guidance for derivatives and hedging permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

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The following tables present for each of the hierarchy levels, Xcel Energy's derivative assets and liabilities that are measured at fair value on a recurring basis at Dec. 31, 2011:

	Dec. 31, 2011					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$169	$-	$169	$ (76)	$93
Other derivative instruments:						
Trading commodity	-	32,682	-	32,682	(13,391)	19,291
Electric commodity	-	-	13,333	13,333	(1,471)	11,862
Total current derivative assets	$-	$32,851	$13,333	$46,184	$ (14,938)	31,246
Purchased power agreements (a)						33,094
Current derivative instruments						$64,340
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$107	$-	$107	$ (59)	$48
Other derivative instruments:						
Trading commodity	-	36,599	-	36,599	(5,540)	31,059
Total noncurrent derivative assets	$-	$36,706	$-	$36,706	$ (5,599)	31,107
Purchased power agreements (a)						121,780
Noncurrent derivative instruments						$152,887

	Dec. 31, 2011					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$-	$57,749	$-	$57,749	$ -	$57,749
Other derivative instruments:						
Trading commodity	-	27,891	-	27,891	(14,417)	13,474
Electric commodity	-	698	916	1,614	(1,471)	143
Natural gas commodity	418	70,119	-	70,537	(7,486)	63,051
Total current derivative liabilities	$418	$156,457	$916	$157,791	$ (23,374)	134,417
Purchased power agreements (a)						22,997

Current derivative instruments						$157,414
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$20,966	$-	$20,966	$ (5,599)	$15,367
Total noncurrent derivative liabilities	$-	$20,966	$-	$20,966	$ (5,599)	15,367
Purchased power agreements (a)						248,539
Noncurrent derivative instruments						$263,906

(a) In 2003, as a result of implementing new guidance on the normal purchase exception for derivative accounting, Xcel Energy began recording several long-term purchased power agreements at fair value due to accounting requirements related to underlying price adjustments. As these purchases are recovered through normal regulatory recovery mechanisms in the respective jurisdictions, the changes in fair value for these contracts were offset by regulatory assets and liabilities. During 2006, Xcel Energy qualified these contracts under the normal purchase exception. Based on this qualification, the contracts are no longer adjusted to fair value and the previous carrying value of these contracts will be amortized over the remaining contract lives along with the offsetting regulatory assets and liabilities.

(b) The accounting guidance for derivatives and hedging permits the netting of receivables and payables for derivatives and related collateral amounts when a legally enforceable master netting agreement exists between Xcel Energy and a counterparty. A master netting agreement is an agreement between two parties who have multiple contracts with each other that provides for the net settlement of all contracts in the event of default on or termination of any one contract.

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The following table presents the changes in Level 3 commodity derivatives for the three and six months ended June 30, 2012 and 2011:

(Thousands of Dollars)	Three Months Ended June 30 2012	2011
Balance at April 1	$ 5,324	$ 2,332
Purchases	37,296	33,609
Settlements	(12,675)	(8,211)
Net transactions recorded during the period:		
Gains recognized in earnings (a)	-	4
Gains (losses) recorded as regulatory assets and liabilities	3,844	(23,738)
Balance at June 30	$ 33,789	$ 3,996

(Thousands of Dollars)	Six Months Ended June 30 2012	2011
Balance at Jan. 1	$ 12,417	$ 2,392
Purchases	37,297	33,609
Settlements	(21,560)	(16,001)
Net transactions recorded during the period:		
(Losses) gains recognized in earnings (a)	(9)	72
Gains (losses) recorded as regulatory assets and liabilities	5,644	(16,076)
Balance at June 30	$ 33,789	$ 3,996

(a)These amounts relate to commodity derivatives held at the end of the period.

Xcel Energy recognizes transfers between levels as of the beginning of each period. There were no transfers of amounts between levels for the three and six months ended June 30, 2012 and 2011.

Fair Value of Long-Term Debt

As of June 30, 2012 and Dec. 31, 2011, other financial instruments for which the carrying amount did not equal fair value were as follows:

	June 30, 2012		Dec. 31, 2011	
(Thousands of Dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$10,017,997	$11,857,476	$9,908,435	$11,734,798

The fair value of Xcel Energy's long-term debt is estimated based on recent trades and observable spreads from benchmark interest rates for similar securities. The fair value estimates are based on information available to management as of June 30, 2012 and Dec. 31, 2011, and given the observability of the inputs to these estimates, the fair values presented for long-term debt have been assigned a Level 2. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since those dates and current estimates of fair values may differ significantly.

9. Other Income, Net

Other income (expense), net consisted of the following:

(Thousands of Dollars)	Three Months Ended June 30		Six Months Ended June 30	
	2012	2011	2012	2011
Interest income	$ 881	$ 1,481	$ 6,503	$ 6,254
Other nonoperating income	1,157	901	2,079	1,784
Insurance policy expense	(1,061)	(1,215)	(3,860)	(2,086)
Other nonoperating expense	(249)	(188)	(257)	(207)
Other income, net	$ 728	$ 979	$ 4,465	$ 5,745

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10. Segment Information

The regulated electric utility operating results of NSP-Minnesota, NSP-Wisconsin, PSCo and SPS, as well as the regulated natural gas utility operating results of NSP-Minnesota, NSP-Wisconsin and PSCo are each separately and regularly reviewed by Xcel Energy's chief operating decision maker. Xcel Energy evaluates performance by each utility subsidiary based on profit or loss generated from the product or service provided. These segments are managed separately because the revenue streams are dependent upon regulated rate recovery, which is separately determined for each segment.

Xcel Energy has the following reportable segments: regulated electric utility, regulated natural gas utility and all other.

- Xcel Energy's regulated electric utility segment generates, transmits, and distributes electricity in Minnesota, Wisconsin, Michigan, North Dakota, South Dakota, Colorado, Texas and New Mexico. In addition, this segment includes sales for resale and provides wholesale transmission service to various entities in the United States. Regulated electric utility also includes commodity trading operations.
- Xcel Energy's regulated natural gas utility segment transports, stores and distributes natural gas primarily in portions of Minnesota, Wisconsin, North Dakota, Michigan and Colorado.
- Revenues from operating segments not included above are below the necessary quantitative thresholds and are therefore included in the all other category. Those primarily include steam revenue, appliance repair services, nonutility real estate activities, revenues associated with processing solid waste into refuse-derived fuel and investments in rental housing projects that qualify for low-income housing tax credits.

Xcel Energy had equity investments in unconsolidated subsidiaries of $100.3 million and $92.7 million as of June 30, 2012 and Dec. 31, 2011, respectively, included in the regulated natural gas segment.

Asset and capital expenditure information is not provided for Xcel Energy's reportable segments because as an integrated electric and natural gas utility, Xcel Energy operates significant assets that are not dedicated to a specific business segment, and reporting assets and capital expenditures by business segment would require arbitrary and potentially misleading allocations which may not necessarily reflect the assets that would be required for the operation of the business segments on a stand-alone basis.

To report income from continuing operations for regulated electric and regulated natural gas utility segments, the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2012					
Operating revenues from external customers	$2,036,829	$221,313	$16,526	$ -	$ 2,274,668
Intersegment revenues	297	219	-	(516)	-
Total revenues	$2,037,126	$221,532	$16,526	$ (516)	$ 2,274,668
Income (loss) from continuing operations	$190,151	$6,190	$(13,266)	$ -	$ 183,075

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended June 30, 2011					

Operating revenues from external customers	$2,128,397	$291,538	$18,287	$ -	$ 2,438,222
Intersegment revenues	356	597	-	(953)	-
Total revenues	$2,128,753	$292,135	$18,287	$ (953)	$ 2,438,222
Income (loss) from continuing operations	$162,482	$6,596	$(10,407)	$ -	$ 158,671

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2012					
Operating revenues from external customers	$3,973,611	$842,348	$36,788	$ -	$ 4,852,747
Intersegment revenues	599	718	-	(1,317)	-
Total revenues	$3,974,210	$843,066	$36,788	$ (1,317)	$ 4,852,747
Income (loss) from continuing operations	$333,372	$56,392	$(22,920)	$ -	$ 366,844

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(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Six Months Ended June 30, 2011					
Operating revenues from external customers	$4,158,369	$1,056,887	$39,506	$ -	$ 5,254,762
Intersegment revenues	695	1,396	-	(2,091)	-
Total revenues	$4,159,064	$1,058,283	$39,506	$ (2,091)	$ 5,254,762
Income (loss) from continuing operations	$317,119	$65,193	$(20,174)	$ -	$ 362,138

11. Earnings Per Share

Basic earnings per share (EPS) was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the weighted average number of common shares outstanding during the period. Diluted EPS was computed by dividing the earnings available to Xcel Energy Inc.'s common shareholders by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock (i.e., common stock equivalents), such as share-based compensation awards were settled. The weighted average number of potentially dilutive shares outstanding used to calculate Xcel Energy Inc.'s diluted EPS is calculated based on the treasury stock method.

Share-Based Compensation
Common stock equivalents related to share-based compensation causing dilutive impact to EPS currently consist of 401(k) equity awards. Stock equivalent units granted to Xcel Energy Inc.'s Board of Directors are included in common shares outstanding upon grant date as there is no further service, performance or market condition associated with these awards. Restricted stock, granted to settle amounts due certain employees under the Xcel Energy Inc. Executive Annual Incentive Award Plan, is included in common shares outstanding when granted, pending remaining service conditions.

Share-based compensation arrangements for which there is currently no dilutive impact to EPS include the following:

- Restricted stock unit equity awards subject to a performance condition; included in common shares outstanding when all necessary conditions for settlement have been satisfied by the end of the reporting period.
- Performance share plan liability awards subject to a performance condition; any portions settled in shares are included in common shares outstanding upon settlement.

The dilutive impact of common stock equivalents affecting EPS was as follows:

	Three Months Ended June 30, 2012			Three Months Ended June 30, 2011		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$183,060			$158,762		
Less: Dividend requirements on preferred stock	-			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	183,060	487,717	$0.38	157,702	484,918	$0.33
Effect of dilutive securities:						
401(k) equity awards	-	300		-	323	
Diluted earnings per share:						
Earnings available to common shareholders	$ 183,060	488,017	$0.38	$ 157,702	485,241	$0.33

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(Amounts in thousands, except per share data)	Six Months Ended June 30, 2012 Income	Shares	Per Share Amount	Six Months Ended June 30, 2011 Income	Shares	Per Share Amount
Net income	$ 366,953			$ 362,331		
Less: Dividend requirements on preferred stock	-			(2,120)		
Basic earnings per share:						
Earnings available to common shareholders	366,953	487,538	$ 0.75	360,211	484,283	$ 0.74
Effect of dilutive securities:						
401(k) equity awards	-	468		-	492	
Diluted earnings per share:						
Earnings available to common shareholders	$ 366,953	488,006	$ 0.75	$ 360,211	484,775	$ 0.74

For the three and six months ended June 30, 2011, Xcel Energy Inc. had approximately 2.4 million and 2.5 million weighted average stock options outstanding, respectively, that were antidilutive, and therefore, excluded from the EPS calculation. No stock options were outstanding at March 31, 2012 or June 30, 2012.

Share Repurchase — In February 2012, Xcel Energy Inc.'s Board of Directors approved the repurchase of up to 0.7 million shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. In March 2012, Xcel Energy Inc. repurchased the approved 0.7 million shares in the open market at an average price of $26.42 per share. In addition, approximately 0.9 million shares of common stock were purchased in February 2012 through an agent independent of Xcel Energy to fulfill requirements for the employer match pursuant to the Xcel Energy 401(k) Savings Plan; the New Century Energies, Inc. Employees' Savings and Stock Ownership Plan for Bargaining Unit Employees and Former Non-Bargaining Unit Employees; and the New Century Energies, Inc. Employee Investment Plan for Bargaining Unit Employees and Non-Bargaining Employees.

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended June 30			
	2012	2011	2012	2011
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$21,853	$20,548	$922	$1,097
Interest cost	39,365	40,791	9,551	10,492
Expected return on plan assets	(52,072)	(55,514)	(7,094)	(8,013)
Amortization of transition obligation	-	-	3,580	3,611
Amortization of prior service cost (credit)	5,267	5,633	(1,888)	(1,233)
Amortization of net loss	27,467	20,527	4,487	3,304
Net periodic benefit cost	41,880	31,985	9,558	9,258
Cost not recognized and additional cost recognized due to the effects of regulation	(10,158)	(10,715)	973	973
Net benefit cost recognized for financial reporting	$31,722	$21,270	$10,531	$10,231

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(Thousands of Dollars)	Six Months Ended June 30 2012	2011	2012	2011
	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$43,182	$38,660	$2,102	$2,412
Interest cost	78,088	80,706	18,931	21,043
Expected return on plan assets	(103,548)	(110,800)	(14,205)	(15,981)
Amortization of transition obligation	-	-	7,160	7,222
Amortization of prior service cost (credit)	10,533	11,266	(3,776)	(2,466)
Amortization of net loss	53,785	39,256	8,452	6,647
Net periodic benefit cost	82,040	59,088	18,664	18,877
Cost not recognized and additional cost recognized due to the effects of regulation	(19,291)	(18,600)	1,946	1,946
Net benefit cost recognized for financial reporting	$62,749	$40,488	$20,610	$20,823

In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans. Xcel Energy does not expect additional pension contributions during 2012.

In June 2012, to manage volatility in equity pricing within the pension master trust, Xcel Energy entered into equity collar contracts with a net-zero cost at initiation on a portion of the equity securities. The equity collar strategy is designed to reduce potential equity losses while limiting gains, resulting in lower equity volatility for the pension plans. At June 30, 2012, the mark-to-market value of these arrangements was not material to the value of the pension trust assets. These arrangements will expire in December 2012.

Item 2 — MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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. Due to the seasonality of Xcel Energy's electric and natural gas sales, interim results are not necessarily an appropriate base from which to project annual results.

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 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. 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 slow down in the U.S. economy or delay in growth recovery; trade, fiscal, taxation and environmental policies in areas where Xcel Energy has a financial interest; customer business conditions; actions of credit rating agencies; competitive factors, including the extent and timing of the entry of additional competition in the markets served by Xcel Energy Inc. and its subsidiaries; unusual weather; effects of geopolitical events, including war and acts of terrorism; state, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rates or have an impact on asset operation or ownership or impose environmental compliance conditions; structures that affect the speed and degree to which competition enters the electric and natural gas markets; costs and other effects of legal and administrative proceedings, settlements, investigations and claims; actions by regulatory bodies impacting our nuclear operations, including those affecting costs, operations or the approval of requests pending before the 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 Continuing Operations; and the other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including “Risk Factors” in Item 1A of Xcel Energy Inc.’s Form 10-K for the year ended Dec. 31, 2011, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.

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Financial Review

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The 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. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to the controlling interest of each subsidiary by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. Xcel Energy's management uses this non-GAAP financial measure to evaluate and provide details of earnings results. Xcel Energy's management believes that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to Xcel Energy's consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

Results of Operations

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	2012	2011	2012	2011
PSCo	$ 0.20	$ 0.15	$ 0.39	$ 0.35
NSP-Minnesota	0.13	0.13	0.29	0.32
SPS	0.06	0.05	0.08	0.07
NSP-Wisconsin	0.01	0.02	0.04	0.05
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility — continuing operations	0.41	0.36	0.82	0.81
Xcel Energy Inc. and other costs	(0.03)	(0.03)	(0.07)	(0.07)
GAAP diluted earnings per share	$ 0.38	$ 0.33	$ 0.75	$ 0.74

Xcel Energy — Overall, earnings increased $0.05 per share for the second quarter and $0.01 per share for the six months ended June 30, 2012. Second quarter 2012 earnings increased largely due to higher electric margin, resulting from various rate increases and warmer than normal weather across all of Xcel Energy's service territories. Higher property taxes and interest expense partially offset the strong electric margins.

PSCo — PSCo earnings increased $0.05 per share during the second quarter of 2012 and $0.04 per share for the six months ended June 30, 2012. The increases are primarily due to an electric rate increase effective in May 2012, lower O&M expenses and the impact of warmer summer weather. The increases were partially offset by decreased wholesale revenue due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

NSP-Minnesota — NSP-Minnesota earnings were flat for the second quarter of 2012 and decreased $0.03 per share for the six months ended June 30, 2012. The year-to-date decrease is primarily due to the unfavorable impact of warmer than normal winter weather, higher property taxes, higher O&M expenses and sluggish electric sales, which were partially offset by the positive impact of summer weather and a lower effective tax rate.

SPS — SPS earnings increased $0.01 per share in both the second quarter of 2012 and the six months ended June 30, 2012. The increases are the result of rate increases in New Mexico and Texas, effective January 2012, partially offset by higher depreciation expense due to Jones Unit 3 going into service in June 2011 and higher property taxes.

NSP-Wisconsin — NSP-Wisconsin earnings decreased $0.01 per share in both the second quarter of 2012 and the six months ended June 30, 2012. The decreases are primarily attributable to the impact of warmer winter weather and higher O&M expenses, partially offset by rate increases effective in January 2012 and the impact of warmer summer weather.

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Changes in Diluted EPS

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

Diluted Earnings (Loss) Per Share	Three Months Ended June 30	Six Months Ended June 30
2011 GAAP diluted earnings per share	$ 0.33	$ 0.74
Components of change — 2012 vs. 2011		
Higher electric margins	0.05	0.02
Lower conservation and DSM expenses (generally offset in revenues)	0.01	0.02
Higher interest charges	(0.01)	(0.02)
Higher taxes (other than income taxes)	(0.01)	(0.02)
Lower effective tax rate	-	0.03
Lower natural gas margins	-	(0.02)
Other, net	0.01	-
2012 GAAP diluted earnings per share	$ 0.38	$ 0.75

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

Contributions to Income (Millions of Dollars)	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
Regulated electric income	$ 190.2	$ 162.5	$ 333.4	$ 317.1
Regulated natural gas income	6.2	6.6	56.4	65.2
All other (a)	3.8	4.8	11.1	9.6
Xcel Energy Inc. and other costs (a)	(17.1)	(15.2)	(34.0)	(29.8)
Total income — continuing operations	183.1	158.7	366.9	362.1
Income from discontinued operations	-	0.1	0.1	0.2
Total net income	$ 183.1	$ 158.8	$ 367.0	$ 362.3

Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended June 30 2012	Three Months Ended June 30 2011	Six Months Ended June 30 2012	Six Months Ended June 30 2011
Regulated electric	$ 0.39	$ 0.34	$ 0.68	$ 0.65
Regulated natural gas	0.01	0.01	0.12	0.14
All other (a)	0.01	0.01	0.02	0.02
Xcel Energy Inc. and other costs (a)	(0.03)	(0.03)	(0.07)	(0.07)
Total earnings per share — continuing operations	0.38	0.33	0.75	0.74
Discontinued operations	-	-	-	-
Total earnings per share — diluted	$ 0.38	$ 0.33	$ 0.75	$ 0.74

(a)Not a reportable segment. Included in all other segment results in Note 10 to the consolidated financial statements.

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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, conversely, mild weather reduces electric and natural gas sales. The estimated impact of weather on earnings is based on the number of customers, temperature variances and the amount of natural gas or electricity the average customer historically uses per degree of temperature. Accordingly, deviations in weather from normal levels can affect Xcel Energy's financial performance.

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

Normal weather conditions are defined as either the 20-year or 30-year average of actual historical weather conditions. The historical period of time used in the calculation of normal weather differs by jurisdiction based on the time period used by the regulator in establishing estimated volumes in the rate setting process.

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

	Three Months Ended June 30			Six Months Ended June 30		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
HDD	(33.1) %	0.9 %	(34.5) %	(21.4) %	4.4 %	(24.3) %
CDD	79.9	33.9	34.3	83.2	33.5	37.6
THI	40.1	(6.4)	49.7	45.7	(6.5)	55.8

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		
	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011	2012 vs. Normal	2011 vs. Normal	2012 vs. 2011
Retail electric	$0.032	$0.004	$0.028	$0.007	$0.011	$(0.004)
Firm natural gas	(0.008)	0.001	(0.009)	(0.029)	0.008	(0.037)
Total	$0.024	$0.005	$0.019	$(0.022)	$0.019	$(0.041)

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

	Three Months Ended June 30	
	Actual	Weather Normalized
Electric residential	2.5 %	(0.8) %
Electric commercial and industrial	2.3	1.1
Total retail electric sales	2.3	0.5
Firm natural gas sales	(25.9)	(4.3)

	Six Months Ended June 30		Six Months Ended June 30 (Without Leap Day)	
	Actual	Weather Normalized	Actual	Weather Normalized
Electric residential	(1.6) %	(0.1) %	(2.1) %	(0.7) %
Electric commercial and industrial	0.8	0.6	0.3	0.1
Total retail electric sales	0.1	0.4	(0.4)	(0.2)
Firm natural gas sales	(17.4)	(0.1)	(18.1)	(0.9)

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 little impact on electric margin. The following table details the electric revenues and margin:

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2012	2011	2012	2011
Electric revenues	$ 2,037	$ 2,128	$ 3,974	$ 4,158
Electric fuel and purchased power	(854)	(989)	(1,718)	(1,921)
Electric margin	$ 1,183	$ 1,139	$ 2,256	$ 2,237

The following tables summarize the components of the changes in electric revenues and electric margin:

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30 2012 vs. 2011	Six Months Ended June 30 2012 vs. 2011
Fuel and purchased power cost recovery	$ (130)	$ (196)
Firm wholesale (a)	(14)	(27)
Trading, including PSCo renewable energy credit sales	(10)	(17)
Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, Michigan, North Dakota and Minnesota) (b)	25	31
Estimated impact of weather	21	(3)
Transmission revenue	13	22
Demand revenue	4	8

Other, net	-	(2)
Total decrease in electric revenues	$ (91)	$ (184)

(a) Decrease is primarily due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

(b) NSP-Minnesota reduced depreciation expense and revenues by approximately $9 million in the second quarter of 2012 and $16 million for the six months ended June 30, 2012 to reflect the settlements in the Minnesota and South Dakota electric rate cases.

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Electric Margin

(Millions of Dollars)	Three Months Ended June 30 2012 vs. 2011	Six Months Ended June 30 2012 vs. 2011
Retail rate increases (Colorado, Texas, New Mexico, Wisconsin, South Dakota, Michigan, North Dakota and Minnesota) (a)	$ 25	$ 31
Estimated impact of weather	21	(3)
Transmission revenue, net of costs	4	9
Demand revenue	4	8
Conservation and DSM incentive	3	5
Firm wholesale (b)	(11)	(22)
Conservation and DSM revenue (offset by expenses)	(3)	(7)
Other, net	1	(2)
Total increase in electric margin	$ 44	$ 19

(a) NSP-Minnesota reduced depreciation expense and revenues by approximately $9 million in the second quarter of 2012 and $16 million for the six months ended June 30, 2012 to reflect the settlements in the Minnesota and South Dakota electric rate cases.

(b) Decrease is primarily due to the expiration of a long-term wholesale power agreement with Black Hills Corp.

Natural Gas Revenues and Margin

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

	Three Months Ended June 30		Six Months Ended June 30	
(Millions of Dollars)	2012	2011	2012	2011
Natural gas revenues	$ 221	$ 292	$ 842	$ 1,057
Cost of natural gas sold and transported	(90)	(163)	(508)	(706)
Natural gas margin	$ 131	$ 129	$ 334	$ 351

The following tables summarize the components of the changes in natural gas revenues and natural gas margin:

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended June 30 2012 vs. 2011	Six Months Ended June 30 2012 vs. 2011
Purchased natural gas adjustment clause recovery	$ (73)	$ (198)
Estimated impact of weather	(7)	(28)
Conservation and DSM revenue (offset by expenses)	(3)	(12)
Pipeline system integrity adjustment rider (Colorado)	8	11
Retail rate increase (Colorado, Wisconsin)	6	9
Return on PSCo gas in storage	1	4

Other, net		(3)		(1)
Total decrease in natural gas revenues	$	(71)	$	(215)

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Natural Gas Margin

(Millions of Dollars)	Three Months Ended June 30 2012 vs. 2011	Six Months Ended June 30 2012 vs. 2011
Pipeline system integrity adjustment rider (Colorado)	$ 8	$ 11
Retail rate increase (Colorado, Wisconsin)	6	9
Return on PSCo gas in storage	1	4
Estimated impact of weather	(7)	(28)
Conservation and DSM revenue (offset by expenses)	(3)	(12)
Other, net	(3)	(1)
Total increase (decrease) in natural gas margin	$ 2	$ (17)

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $1.8 million, or 0.3 percent, for the second quarter of 2012 and $2.5 million, or 0.2 percent, for the six months ended June 30, 2012, compared with the same periods in 2011. The higher expenses are primarily attributable to higher pension expense, partially offset by management cost savings initiatives.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses decreased $6.9 million, or 10.5 percent, for the second quarter of 2012 and $18.5 million, or 13.1 percent, for the six months ended June 30, 2012, compared with the same periods in 2011. The lower expense is primarily attributable to lower gas rider rates, as well as the timing of recovery of electric conservation improvement program expenses at NSP-Minnesota. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates.

Depreciation and Amortization — Depreciation and amortization decreased $2.6 million, or 1.1 percent, for the second quarter of 2012 and increased $1.3 million, or 0.3 percent, for the six months ended June 30, 2012, compared with the same periods in 2011. The change is primarily due to normal system expansion across Xcel Energy's service territories, partially offset by a change in depreciation lives for certain assets to reflect the settlements in the Minnesota and South Dakota electric rate cases. This change in depreciation lives resulted in a reduction in depreciation expense of approximately $9 million for the second quarter of 2012 and approximately $16 million for the six months ended June 30, 2012.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased $7.1 million, or 7.7 percent, for the second quarter of 2012 and $16.2 million, or 8.6 percent, for the six months ended June 30, 2012, compared with the same periods in 2011. The increases are due to an increase in property taxes primarily in Minnesota. Increases in property taxes in Colorado related to the electric retail business are being deferred, based on the multi-year rate settlement that was approved by the CPUC in 2012.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased $1.4 million, or 6.7 percent, for the second quarter of 2012 and $0.8 million, or 1.9 percent, for the six months ended June 30, 2012, compared with the same periods in 2011. The increases are primarily due to the expansion of PSCo's transmission facilities, additional construction related to the CACJA and normal system expansion.

Interest Charges — Interest charges increased $5.6 million, or 3.8 percent, for the second quarter of 2012 and $13.1 million, or 4.5 percent, for the six months ended June 30, 2012, compared with the same periods in 2011. The increases are due to higher long-term debt levels to fund investments in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense increased $17.3 million for the second quarter of 2012, compared with the same period in 2011. The increase in income tax expense was primarily due to an increase in pretax income in 2012. The effective tax rate was 35.7 percent for the second quarter of 2012 compared with 34.8 percent for the same period in 2011. The higher effective tax rate for 2012 was primarily due to a higher forecasted annual effective tax rate, which was mainly attributable to increased state income taxes in 2012.

Income tax expense decreased $19.2 million for the first six months of 2012, compared with the same period in 2011. The decrease in income tax expense was primarily due to lower pretax earnings and a tax benefit associated with a carryback. The effective tax rate for continuing operations was 32.6 percent for the six months ended June 30, 2012 compared with 35.2 percent for the same period in 2011. The lower effective tax rate for 2012 was primarily due to the completion of an analysis in the first quarter on the eligibility of certain expenses that qualified for an extended carryback beyond the typical two-year carryback period. As a result, Xcel Energy recognized a discrete tax benefit of approximately $15 million. Without this tax benefit, the effective tax rate would have been 35.3 percent for the six months ended June 30, 2012.

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Factors Affecting Results of Operations

Fuel Supply and Costs

See the discussion of fuel supply and costs in Item 1 in Xcel Energy Inc.'s Annual Report on Form 10-K filed for the year ended Dec. 31, 2011.

Public Utility Regulation

NSP-Minnesota

NSP System Resource Plans — In December 2011, NSP-Minnesota filed an update to the 2011 through 2025 resource plan with the MPUC. To account for slower projected economic growth and the loss of NSP-Wisconsin's wholesale customers, NSP-Minnesota modified the current plan to include a administrative to withdraw the Black Dog repowering project certificate of need (CON) and to reassess the wind procurement plan and resource contingency plan in detail. In May 2012, an adminstrative law judge (ALJ) granted NSP-Minnesota's request to withdraw the CON application; the ALJ decision is pending MPUC action.

The resource plan update also notified the MPUC that there have been changes in the size, timing, and cost estimates for the extended power uprate project at the Prairie Island nuclear generating plant. In March 2012, NSP-Minnesota made a change of circumstances (COC) filing providing a new economic and project design analysis and seeking MPUC guidance before proceeding with the extended power uprate project. The COC filing indicated the costs of the Prairie Island uprate project have increased, and the cost savings relative to other resource options have declined and may even be negative under certain assumptions. The COC filing is pending MPUC action. Some elements of the resource plan remain unchanged such as the extension of certain contracts, the Monticello nuclear generating plant extended power uprate project and the commitment to specific conservation improvement program annual achievements.

NSP-Minnesota CapX2020 CON — In 2009, the MPUC granted CONs to construct one 230 kilovolt (KV) electric transmission line and three 345 KV electric transmission lines as part of the CapX2020 project. The estimated cost of the four major transmission projects is $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.1 billion of the total cost. The remainder of the costs will be borne by other utilities in the upper Midwest. These cost estimates will be revised after the regulatory process is completed.

The MPUC has issued route permits for the Minnesota portion of the Fargo, N.D. to St. Cloud, Minn. project, the Brookings, S.D. project, the Bemidji, Minn. to Grand Rapids, Minn. project and for the portions of the new transmission lines between Hampton, Minn. and La Crosse, Wis. to be constructed in Minnesota. In June 2011, the SDPUC approved a facility permit for a portion of the Brookings, S.D. project. The NDPSC granted a CPCN in January 2011. It is expected the NDPSC will approve the remaining required Certificate of Corridor Compatibility and Route Permit activities in North Dakota in August 2012.

In December 2011, the Monticello, Minn. to St. Cloud, Minn. 345 KV project was placed in service and MISO granted the final approval of the Brookings, S.D. project as a multi-value project.

NSP-Wisconsin

NSP-Wisconsin CapX2020 CPCN — The PSCW issued a CPCN for the Wisconsin portion of the CapX2020 Hampton, Minn. to La Crosse, Wis. 345 KV project on May 30, 2012. The Wisconsin portion consists of approximately 50 miles of new transmission line. The route approved by the PSCW differed slightly from the route preferred by

NSP-Wisconsin. The cost for the approved route is estimated at $211 million. Construction on the Wisconsin portion of the line is anticipated to begin in 2013 and the line is expected to go into service in 2015.

PSCo

PSCo Resource Plan — PSCo's 2011 electric resource plan addressed concerns that PSCo is projected to have relatively low resource needs beginning in 2017, and has proposed to fill these needs with a competitive resource acquisition process. The CPUC is expected to consider the resource plan in two phases. In the first phase, the CPUC is expected to review planning assumptions, competitive bidding structure, and determine if PSCo should acquire generation technology. The first phase is expected to be completed by the end of 2012. In the second phase, PSCo expects to conduct the competitive acquisition process, which is expected to be submitted to the CPUC for approval in 2013.

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In July 2012, PSCo filed two separate applications which, if approved, would update the existing resources considered in its Resource Plan. The first is an application to purchase Brush Power, LLC and all of its assets including Brush generating Units 1, 3 and 4 for a total purchase price of approximately $75 million. Located in Brush, Colo., the generating units have a total capacity of 237 MW, including Brush Unit 1, a 60 MW combined-cycle unit; Brush Unit 3, a 30 MW simple-cycle unit; and Brush Unit 4, a 147 MW combined-cycle unit. The purchase is subject to various regulatory approvals including that of the CPUC. The Brush units currently provide energy and capacity to PSCo under purchased power agreements that are set to expire in 2017 for Brush Unit 1 and Brush Unit 3, and 2022 for Brush Unit 4. The transaction, if approved, is expected to result in savings to wholesale and retail customers.

The second application seeks approval to retire Arapahoe Unit 4, a 109 MW coal-fired company-owned generating station at the end of 2013. This would be an alternative to permanently fuel switching Arapahoe Unit 4 to natural gas and instead replacing the capacity and associated energy with a natural gas purchased power agreement with an existing generator. A decision on both applications is expected between December 2012 and March 2013.

PSCo Renewable Energy Standard (RES) Compliance Plan — Colorado law mandates that at least 30 percent of PSCo's energy sales be supplied by renewable energy by 2020 and includes a distributed generation standard. PSCo has filed the 2012 and 2013 RES compliance plan. PSCo proposed to acquire up to 30 MW of customer-sited solar projects each year and up to 6 MW of community scale solar projects. In March 2012, the ALJ issued a recommended decision largely approving PSCo's proposed levels of acquisition which was affirmed by the CPUC in June 2012. PSCo has sought reconsideration of the order regarding the limit on the amounts that can be advanced to the RESA each year to cover the incremental costs of renewable energy. The CPUC also approved moving solely to a pay-for-performance basis under the Solar*Rewards distributed solar generation program, which PSCo implemented in June 2012.

CACJA — The CACJA required PSCo to file a comprehensive plan to reduce annual emissions of NOx from the coal-fired generation identified in the plan by at least 70 to 80 percent or greater from 2008 levels by 2017. The plan allows PSCo to propose emission controls, plant refueling, or plant retirement of at least 900 MW of coal-fired generating units in Colorado by 2017. The total investment associated with the adopted plan is approximately $1.0 billion through 2017 and the rate impact is expected to increase future bills on average by 2 percent annually.

PSCo's plan as of June 30, 2012 is as follows:

- Shutdown Cherokee Units 2 and 1 in 2011 and 2012, respectively, and Cherokee Unit 3 (365 MW in total) by the end of 2016, after a new natural gas combined-cycle unit is built at Cherokee Station (569 MW);
- Fuel-switch Cherokee Unit 4 (352 MW) to natural gas by 2017;
- Shutdown Arapahoe Unit 3 (45 MW) and Unit 4 (111 MW) in 2013;
- Shutdown Valmont Unit 5 (186 MW) in 2017;
- Install SCR for controlling NOx and a scrubber for controlling SO2 on Pawnee Generating Station in 2014;
- Install SCRs on Hayden Unit 1 in 2015 and Hayden Unit 2 in 2016; and
- Convert Cherokee Unit 2 to a synchronous condenser to support the transmission system in 2012.

PSCo has received CPCNs for the conversion of Cherokee Unit 2 to a synchronous condenser, for the decommissioning of Cherokee Unit 1 and Unit 2, for the Pawnee emissions controls, and for the new natural gas combined-cycle unit at Cherokee Station. The ALJ recommended granting the CPCN for the Hayden emissions controls in June 2012 and one party has sought exceptions to that order.

Separately, in July 2012, PSCo sought approval to modify the original plan to retire Arapahoe Units 3 and 4. Subsequent transmission studies have determined that the synchronous condenser on Arapahoe Unit 3 is not needed for transmission system reliability given other upgrades to the system. PSCo has also found that a purchased power agreement with an existing generator is more cost effective than operating Arapahoe Unit 4 on natural gas. Decisions on both applications are expected by the end of the first quarter of 2013.

PSCo SmartGridCity™ (SGC) Cost Recovery — As part of its 2010 electric rate case, PSCo requested recovery of the revenue requirements associated with $45 million of capital and $4 million of annual O&M costs incurred to develop and operate SGC. In February 2011, the CPUC allowed recovery of approximately $28 million of the capital cost and 100 percent of the O&M costs.

In December 2011, PSCo requested CPUC approval for the recovery of the remaining capital investment in SGC and also provided the additional information requested. In June 2012, the City of Boulder and the Colorado Office of Consumer Counsel filed testimony and recommend the CPUC deny PSCo’s request for recovery of the remaining portion of the SGC investment. A decision is expected in the third quarter of 2012.

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Summary of Recent Federal Regulatory Developments

The FERC has jurisdiction over rates for electric transmission service in interstate commerce and electricity sold at wholesale, hydro facility licensing, natural gas transportation, accounting practices and certain other activities of Xcel Energy Inc.'s utility subsidiaries, including enforcement of North American Electric Reliability Corporation mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility subsidiaries' activities, including regulation of retail rates and environmental matters. See additional discussion in the summary of recent federal regulatory developments and public utility regulation sections of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2011. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In July 2011, the FERC issued Order 1000 adopting new requirements for transmission planning, cost allocation, and development. On April 18, 2012, the Minnesota Governor signed legislation that preserves the rights of incumbent utilities to construct and own transmission interconnected to their systems. This legislation is similar to the legislation previously passed in North Dakota and South Dakota. Therefore, Order 1000 is expected to have limited impacts on future transmission development and ownership in the NSP System in Minnesota, North Dakota, and South Dakota. The NSP System is the integrated electric production and transmission system of NSP-Minnesota and NSP-Wisconsin, which is managed by NSP-Minnesota. The impacts of the new requirements relating to future transmission development and ownership in Wisconsin are uncertain.

Xcel Energy believes that statutes in Texas also protect the right of incumbent utilities to construct and own transmission interconnected to their systems, so Xcel Energy does not expect that this aspect of Order 1000 will impact the portion of SPS in Texas. However, the portion of SPS in New Mexico and PSCo may be impacted by the provisions of Order 1000 that impact an incumbent's right to build transmission because neither New Mexico nor Colorado has legislation protecting the rights of utilities to develop transmission projects in their service areas. Compliance filings to address these new requirements are due October 2012, though SPP has recently filed for an extension, and are effective prospectively.

In May 2012, the FERC issued Order 1000-A, its order on rehearing of Order 1000. Order 1000-A declined all motions for rehearing and offered limited clarification of aspects of the final rule. Several parties filed requests for clarification of Order 1000-A. Several appeals of Order 1000 have also been filed and these appeals have been consolidated into the D.C. Circuit. These appeals are expected to be heard over the next 12 months with a ruling expected sometime in mid-2013.

La Crosse, Wis. to Madison, Wis. Transmission Line Complaint — In February 2012, Xcel Energy and NSP-Wisconsin filed a complaint with the FERC concerning ownership of the proposed La Crosse, Wis. to Madison, Wis. 345 KV transmission line. The complaint stated that MISO had determined that the line is to be owned by NSP-Wisconsin and American Transmission Company LLC (ATC) under the terms of the MISO Transmission Owners Agreement (TOA) and Tariff. However, ATC asserted a different interpretation of the TOA and Tariff provisions that would effectively deny NSP-Wisconsin the ability to invest $175 million in the proposed multi-value project. On July 19, 2012, the FERC granted Xcel Energy and NSP-Wisconsin's complaint, ruling that the responsibilities to construct the La Crosse, Wis. to Madison, Wis. transmission line belong equally to both parties, NSP-Wisconsin, and ATC.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant and the Prairie Island plant. See Note 14 of Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011 for further discussion regarding the nuclear generating plants. Nuclear power plant operation produces gaseous, liquid and solid radioactive wastes. The discharge and handling of such wastes are controlled by federal regulation. High-level radioactive wastes primarily include used nuclear fuel. Low-level radioactive waste consists primarily of demineralizer resins, paper, protective clothing, rags, tools and equipment that have become contaminated through use in the plant.

NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear generating plants. The event at the nuclear generating plant in Fukushima, Japan in 2011 could impact the NRC's deliberations on NSP-Minnesota's power uprates and could also result in additional regulation, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force that has developed recommendations on whether it should require immediate emergency preparedness and mitigating enhancements at U.S. reactors and any changes to NRC regulations, inspection procedures, and licensing processes. In July 2011, the task force released its recommendations in a written report which recommends actions to enhance U.S. nuclear generating plant readiness to safely manage severe events.

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In March 2012, the NRC issued three orders and a request for additional information to all licensees. The orders included requirements for mitigation strategies for beyond-design-basis external events, requirements with regard to reliable spent fuel instrumentation, and requirements with regard to reliable hardened containment vents, which are applicable to boiling water reactor containments at the Monticello plant. The request for additional information included requirements to perform walkdowns of seismic and flood protection, to evaluate seismic and flood hazards, and to assess the emergency preparedness staffing and communications capabilities at each plant. NSP-Minnesota expects that complying with these requirements will cost approximately $20 to $50 million at the Monticello and Prairie Island plants. Based on current refueling outage plans specific to each nuclear facility, the dates of the required compliance begin in the second quarter of 2015 with all units being fully compliant by December 2016. NSP-Minnesota believes the costs associated with compliance would be recoverable from customers through regulatory mechanisms and does not expect a material impact on its results of operations, financial position, or cash flows.

NRC Waste Confidence Decision (WCD) — In June 2012, the D.C. Circuit issued a ruling to vacate and remand the NRC's WCD. The WCD assesses how long temporary on-site storage can remain safe and when facilities for the disposal of nuclear waste will become available. The D.C. Circuit remanded the WCD to the NRC and directed them to prepare an environmental impact statement if there are significant impacts or an environmental assessment to support a finding of no significant impact. NSP-Minnesota is reviewing the decision and believes that there will not be an immediate impact for operations at the Prairie Island or Monticello nuclear generating plants.

Nuclear Plant Power Uprates

Prairie Island Nuclear Extended Power Uprate — In 2009, the MPUC approved a CON for an extended power uprate of approximately 164 MW for Prairie Island Units 1 and 2. Recent analysis of the extended power uprate submittals to the NRC concluded that significant additional design work beyond NSP-Minnesota's estimated schedule and cost plan would be required for a successful application submittal. The analysis demonstrates the magnitude of the benefits is substantially lower than originally anticipated. As a result, NSP-Minnesota completed an economic and new project design analysis and submitted a COC filing with the MPUC in March 2012. As part of the analysis, potential prospective risks were identified that could further reduce the anticipated economic benefits of the project. NSP-Minnesota asked the MPUC to confirm that the extended power uprate project is in the best interest of customers prior to NSP-Minnesota making the significant investments necessary to complete an application and undertake the NRC licensing process. Public comments have been received both in support of and challenging the continuation of the project. NSP-Minnesota is working to facilitate interaction between parties to ensure a common understanding of the benefits and challenges to the project before the MPUC renders a decision. The COC filing is pending MPUC action.

Monticello Nuclear Plant Extended Power Uprate — In 2008, NSP-Minnesota filed for both state and federal approvals of an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello nuclear generating plant. The MPUC approved the CON for the extended power uprate in 2008. The filing was placed on hold by the NRC staff to address concerns raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. NSP-Minnesota has been working with the industry and regulatory agencies to address this issue and expects to submit an update to the application for approval to the NRC in the fourth quarter of 2012, which could result in approval of the extended power uprate project by the NRC in the second quarter of 2013. NSP-Minnesota is planning to implement the equipment changes needed to support the Monticello life extension and power uprate projects in the planned spring 2013 refueling outage.

Environmental, Legal and Other Matters

See a discussion of environmental, legal and other matters in Note 6 to the consolidated financial statements.

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 necessarily 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 even if the nature of the accounting policies applied have not changed. Item 7 — Management's Discussion and Analysis, in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011, includes a discussion of accounting policies and estimates that are most significant to the portrayal of Xcel Energy's financial condition and results, and that 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. As of June 30, 2012, there have been no material changes to policies set forth in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2011.

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Pending Accounting Changes

See a discussion of recently issued accounting pronouncements and pending accounting changes in Note 2 to the consolidated financial statements.

Derivatives, Risk Management and Market Risk

In the normal course of business, Xcel Energy Inc. and its subsidiaries are exposed to a variety of market risks. Market risk is the potential loss or gain that may occur as a result of 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 8 to the consolidated financial statements for further discussion of market risks associated with derivatives.

Xcel Energy is exposed to the impact of 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 nonperformance 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.

Short-Term Wholesale and Commodity Trading Risk — Xcel Energy Inc.’s utility subsidiaries conduct various short-term 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.

Changes in the fair value of commodity trading contracts before the impacts of margin-sharing mechanisms were as follows:

	Six Months Ended June 30	
(Thousands of Dollars)	2012	2011
Fair value of commodity trading net contract assets outstanding at Jan. 1	$ 20,424	$ 20,249
Contracts realized or settled during the period	(6,070)	(7,113)
Commodity trading contract additions and changes during period	6,899	10,544
Fair value of commodity trading net contract assets outstanding at June 30	$ 21,253	$ 23,680

At June 30, 2012, the fair values by source for the commodity trading net asset balances 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	$5,508	$ 14,489	$ 310	$ -	$ 20,307
PSCo	1	474	472	-	-	946
		$5,982	$ 14,961	$ 310	$ -	$ 21,253

1 — Prices actively quoted or based on actively quoted prices.

At June 30, 2012, a 10 percent increase or decrease in market prices for commodity trading contracts would have an immaterial impact to pretax income from continuing operations.

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Xcel Energy's short-term 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)	Period Ended June 30	VaR Limit	Average	High	Low
2012	$ 0.49	$ 3.00	$ 0.42	$ 1.56	$ 0.15
2011	0.32	3.00	0.18	0.33	0.08

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 June 30, 2012, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $475 million related to expected 2012 debt issuances.

At June 30, 2012, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $6.3 million annually. See Note 8 to the consolidated financial statements for a discussion of Xcel Energy Inc. and its subsidiaries' interest rate derivatives.

Xcel Energy 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 June 30, 2012, 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. The accounting for nuclear decommissioning recognizes that costs are recovered through rates; therefore, fluctuations in equity prices or interest rates do not have an 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 June 30, 2012, a 10 percent increase in commodity prices would have resulted in a decrease in credit exposure of $6.4 million, while a decrease of 10 percent in prices would have resulted in an increase in credit exposure of $9.4 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 generally requires that the most observable inputs available be used for fair value measurements. See Note 8 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 June 30, 2012. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues when necessary. 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 June 30, 2012.

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Commodity derivative assets and liabilities assigned to Level 3 typically consist of FTRs and forwards and options that are long-term in nature. Level 3 commodity derivative assets and liabilities represent 2.4 percent and 1.8 percent, respectively, of total assets and liabilities measured at fair value at June 30, 2012.

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 $35.7 million and $1.9 million of estimated fair values, respectively, for FTRs held at June 30, 2012.

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 commodity forwards or options held at June 30, 2012.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities, private equity investments and real estate investments. To the extent appropriate, observable active market inputs are utilized to estimate the fair value of asset-backed and mortgage-backed securities. However, less observable and subjective inputs that may be used in conjunction with available pricing of similar securities in active markets can be significant to these valuations. These inputs include estimated principal prepayments and risk-based adjustments to the interest rate used to discount expected future cash flows in a discounted cash flow model. Given the potential significant impacts that unobservable inputs may have on the valuations of asset-backed and mortgage-backed securities, and 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 $129.4 million in the nuclear decommissioning fund at June 30, 2012 (approximately 8.8 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

	Six Months Ended June 30	
(Millions of Dollars)	2012	2011
Net cash provided by operating activities	$ 865	$ 1,123

Net cash provided by operating activities decreased by $258 million for the six months ended June 30, 2012, compared with the six months ended June 30, 2011. The decrease was a result of changes in working capital due to timing of payments and receipts, higher pension contributions and the effect of the income taxes paid in 2012 compared to the refund received in 2011.

	Six Months Ended June 30	
(Millions of Dollars)	2012	2011
Net cash used in investing activities	$ (956)	$ (1,090)

Net cash used in investing activities decreased by $134 million for the six months ended June 30, 2012, compared with the six months ended June 30, 2011. The decrease was a result of the change in restricted cash due to customer refunds associated with the nuclear waste disposal settlement with the U.S. Department of Energy, the receipt of insurance proceeds for Sherco Unit 3, and higher capital expenditures in 2011, primarily related to the Monticello enhanced power uprate project at NSP-Minnesota, partially offset by expansion of PSCo's transmission facilities and construction related to the CACJA in 2012. In November 2011, Sherco Unit 3 experienced a significant failure of its turbine, generator, and exciter systems and was shut down for replacement and repair of damaged systems.

	Six Months Ended June 30	
(Millions of Dollars)	2012	2011
Net cash provided by (used in) financing activities	$ 94	$ (40)

Net cash provided by financing activities increased by $134 million for the six months ended June 30, 2012, compared with the six months ended June 30, 2011. The increase was primarily due to higher proceeds from short-term borrowings and the issuance of long-term debt, partially offset by repurchases of common stock and higher dividend payments.

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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.

Regulation of Derivatives — In July 2010, financial reform legislation was passed, which provides for the regulation of derivative transactions amongst other provisions. Provisions within the bill provide the Commodity Futures Trading Commission (CFTC) and 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. Additionally there may be material increased reporting requirements. The bill contains provisions that should exempt certain derivatives end users from much of the clearing and margining requirements. In April 2012, The CFTC has ruled that swap dealing activity conducted by companies under a notional limit, initially set at $8 billion with further potential reduction to $3 billion after five years, will fall under the de minimis exemption level and will not be subject to registering as a swap dealer. Xcel Energy's current and projected swap activity is below this de minimis level. The CFTC has set a $25 million de minimis exemption for swaps with "Special Entities," as defined by the CFTC primarily government entities, after which the entity would have to register as a swap dealer. This small limit for swap activity with "Special Entities" could reduce the volume of activity Xcel Energy conducts with such entities. In addition, although the CFTC's proposed rules would extend the end user exemption to margin requirements, they would impose a requirement to have credit support agreements in their place. The full implications for Xcel Energy can not yet be determined until all the definitions and rulemakings are completed.

FERC Order 741 addresses rulemaking addressing the credit policies of organized electric markets and limits the amount of overall credit available to entities operating and places restrictions on netting of transactions within organized markets unless certain market protocols are implemented by the RTO. The various RTOs have filed their proposed market protocols to satisfy FERC Order 741 and the new market designs proposed are for the RTOs to become the central counterparty. Having an RTO serve as the central counterparty should allow for certain types of netting within the RTO and should reduce the overall credit and margin exposure facing Xcel Energy.

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 securities, and alternative investments, including private equity, real estate and commodity index investments. In January 2012, contributions of $190.5 million were made across four of Xcel Energy's pension plans. In 2011, contributions of $137.3 million were made across three of Xcel Energy's pension plans. For future years, we anticipate contributions will be made as necessary.

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 accounts with Wells Fargo Bank. At June 30, 2012, approximately $3.6 million of cash was held in these liquid operating accounts.

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:

- $800 million for Xcel Energy Inc.;
- $700 million for PSCo;
- $500 million for NSP-Minnesota;
- $300 million for SPS; and
- $150 million for NSP-Wisconsin.

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Commercial paper outstanding for Xcel Energy was as follows:

(Millions of Dollars, Except Interest Rates)	Three Months Ended June 30, 2012		Twelve Months Ended Dec. 31, 2011	
Borrowing limit	$ 2,450		$ 2,450	
Amount outstanding at period end	481		219	
Average amount outstanding	456		430	
Maximum amount outstanding	634		824	
Weighted average interest rate, computed on a daily basis	0.37	%	0.36	%
Weighted average interest rate at period end	0.35		0.40	

Credit Facilities —As of July 30, 2012, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility (a)	Drawn (b)	Available	Cash	Liquidity
Xcel Energy Inc.	$800.0	$462.0	$338.0	$0.4	$338.4
PSCo	700.0	41.0	659.0	1.0	660.0
NSP-Minnesota	500.0	8.7	491.3	0.9	492.2
SPS	300.0	-	300.0	0.3	300.3
NSP-Wisconsin	150.0	113.0	37.0	1.0	38.0
Total	$2,450.0	$624.7	$1,825.3	$3.6	$1,828.9

(a)These credit facilities expire in July 2017.
(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 during 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.

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. In June 2012, SPS issued $100 million of first mortgage bonds. Xcel Energy Inc. and its utility subsidiaries anticipate issuing the following during the remainder of 2012:

- NSP-Minnesota may issue approximately $800 million of first mortgage bonds in the third quarter of 2012.
- PSCo may issue approximately $800 million of first mortgage bonds in the third quarter of 2012.
- NSP-Wisconsin may issue approximately $100 million of first mortgage bonds in the second half of 2012.

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.

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Earnings Guidance

Xcel Energy's 2012 earnings is expected to be in the lower half of the guidance range of $1.75 to $1.85 per share. Key assumptions related to earnings are detailed below:

- Constructive outcomes in all remaining rate case and regulatory proceedings.
- Normal weather patterns are experienced for the remainder of the year.
- Weather-adjusted retail electric utility sales are projected to be relatively flat.
- Weather-adjusted retail firm natural gas sales are projected to be relatively flat.
- Rider revenue recovery is projected to increase approximately $35 million to $45 million over 2011 levels.
- O&M expenses are projected to increase up to 1.0 percent over 2011 levels.
- Depreciation and amortization expense is projected to increase $40 million to $50 million over 2011 levels.
- Property taxes are projected to increase $25 million to $30 million over 2011 levels.
- Interest expense (net of AFUDC — debt) is projected to increase approximately $10 million.
- AFUDC — equity is projected to increase approximately $10 million to $20 million over 2011 levels.
- The effective tax rate is projected to be approximately 34 percent to 35 percent.
- Average common stock and equivalents are projected to be approximately 488 million shares.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis under Item 2.

Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of June 30, 2012, based on an evaluation carried out under the supervision and with the participation of Xcel Energy's management, including the CEO and CFO, of the effectiveness of its disclosure controls and the procedures, the CEO and CFO have concluded that Xcel Energy's disclosure controls and procedures were effective.

Internal Control Over Financial Reporting

No change in Xcel Energy's internal control over financial reporting has occurred during the most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, Xcel Energy's internal control over financial reporting.

Part II — OTHER INFORMATION

Item 1 — LEGAL PROCEEDINGS

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Additional Information

See Note 6 to the consolidated financial statements for further discussion of legal claims and environmental proceedings. See Note 5 to the consolidated financial statements for discussion of proceedings involving utility rates and other regulatory matters.

Item 1A — RISK FACTORS

Xcel Energy Inc.'s risk factors are documented in Item 1A of Part I of its Annual Report on Form 10-K for the year ended Dec. 31, 2011, which is incorporated herein by reference.

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Item 2 — UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

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, 2012 — Jan. 31, 2012 (a)	17,487	$ 26.69	-	-
Feb. 1, 2012 — Feb. 29, 2012	-	-	-	-
March 1, 2012 — March 31, 2012 (b)	700,000	26.42	-	-
April 1, 2012 — April 30, 2012	-	-	-	-
May 1, 2012 — May 31, 2012	-	-	-	-
June 1, 2012 — June 30, 2012	-	-	-	-
Total	717,487		-	-

(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.

(b) The Xcel Energy Inc. Board of Directors approved the repurchase of up to 700,000 shares of common stock for the issuance of shares in connection with the vesting of awards under the Xcel Energy Inc. 2005 Long-Term Incentive Plan. Purchases were authorized to be made in the open market pursuant to Rule 10b-18.

Item 4 — MINE SAFETY DISCLOSURES

None.

Item 5 — OTHER INFORMATION

None.

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 17, 2012 (Exhibit 3.01 to Form 8-K dated May 16, 2012 (file no. 001-03034)).
3.02*	Restated By-Laws of Xcel Energy Inc. (Exhibit 3.01 to Form 8-K dated Aug. 12, 2008 (file no. 001-03034)).
31.01	Principal Executive Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.02	Principal Financial Officer's certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.
101	The following materials from Xcel Energy Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2012 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated

Statements of Income, (ii) the Consolidated Statements of Comprehensive Income (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Balance Sheets, (v) the Consolidated Statements of Common Stockholders' Equity, (vi) Notes to Consolidated Financial Statements, and (vii) document and entity information.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

XCEL ENERGY INC.

Aug. 3, 2012

By: /s/ JEFFREY S. SAVAGE
Jeffrey S. Savage
Vice President and Controller
(Principal Accounting Officer)

/s/ TERESA S. MADDEN
Teresa S. Madden
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)