XCEL ENERGY INC
Form 10-Q
July 29, 2011

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, 2011
or

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

Commission File Number: 1-3034

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). £Yes 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 19, 2011
Common Stock, $2.50 par value	484,557,036 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, a Colorado corporation (PSCo); and Southwestern Public Service Company, a New Mexico corporation (SPS). 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,	
	2011	2010	2011	2010
Operating revenues				
Electric	$ 2,128,397	$ 2,040,702	$ 4,158,369	$ 4,036,294
Natural gas	291,538	249,410	1,056,887	1,039,560
Other	18,287	17,652	39,506	39,372
Total operating revenues	2,438,222	2,307,764	5,254,762	5,115,226
Operating expenses				
Electric fuel and purchased power	989,413	986,088	1,921,241	1,974,566
Cost of natural gas sold and transported	163,056	126,963	706,432	708,076
Cost of sales — other	6,891	4,704	14,946	12,396
Other operating and maintenance expenses	532,170	516,640	1,042,197	997,613
Conservation and demand side management program expenses	65,497	55,551	140,795	113,590
Depreciation and amortization	229,264	211,506	453,987	417,632
Taxes (other than income taxes)	92,489	81,008	189,059	162,384
Total operating expenses	2,078,780	1,982,460	4,468,657	4,386,257
Operating income	359,442	325,304	786,105	728,969
Other income, net	979	1,709	5,745	2,684
Equity earnings of unconsolidated subsidiaries	7,677	7,362	15,390	14,763
Allowance for funds used during construction — equity	13,606	12,996	26,850	26,286
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,185, $5,146, $11,445 and $10,157, respectively	146,338	141,455	290,692	285,285
Allowance for funds used during construction — debt	(7,838)	(6,575)	(15,274)	(14,312)
Total interest charges and financing costs	138,500	134,880	275,418	270,973
Income from continuing operations before income taxes	243,204	212,491	558,672	501,729
Income taxes	84,533	76,866	196,534	198,764
Income from continuing operations	158,671	135,625	362,138	302,965
Income from discontinued operations, net of tax	91	4,151	193	3,929

Net income	158,762	139,776	362,331	306,894
Dividend requirements on preferred stock	1,060	1,060	2,120	2,120
Earnings available to common shareholders	$ 157,702	$ 138,716	$ 360,211	$ 304,774
Weighted average common shares outstanding:				
Basic	484,918	460,041	484,283	459,483
Diluted	485,241	460,432	484,775	460,068
Earnings per average common share — basic:				
Income from continuing operations	$ 0.33	$ 0.29	$ 0.74	$ 0.65
Income from discontinued operations	-	0.01	-	0.01
Earnings per share	$ 0.33	$ 0.30	$ 0.74	$ 0.66
Earnings per average common share — diluted:				
Income from continuing operations	$ 0.33	$ 0.29	$ 0.74	$ 0.65
Income from discontinued operations	-	0.01	-	0.01
Earnings per share	$ 0.33	$ 0.30	$ 0.74	$ 0.66
Cash dividends declared per common share	$ 0.26	$ 0.25	$ 0.51	$ 0.50

See Notes to Consolidated Financial Statements

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

	Six Months Ended June 30,	
	2011	2010
Operating activities		
Net income	$362,331	$306,894
Remove income from discontinued operations	(193)	(3,929)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	463,013	421,820
Conservation and demand side management program amortization	6,078	15,514
Nuclear fuel amortization	43,732	49,551
Deferred income taxes	197,637	171,260
Amortization of investment tax credits	(3,160)	(3,188)
Allowance for equity funds used during construction	(26,850)	(26,286)
Equity earnings of unconsolidated subsidiaries	(15,390)	(14,763)
Dividends from unconsolidated subsidiaries	16,931	15,791
Share-based compensation expense	20,299	16,470
Net realized and unrealized hedging and derivative transactions	16,802	(21,374)
Changes in operating assets and liabilities:		
Accounts receivable	38,914	73,118
Accrued unbilled revenues	117,836	140,035
Inventories	76,028	101,822
Other current assets	52,397	29,703
Accounts payable	32,116	(226,436)
Net regulatory assets and liabilities	(41,888)	27,643
Other current liabilities	(78,110)	(139,252)
Pension and other employee benefit obligations	(131,892)	(7,169)
Change in other noncurrent assets	13,119	1,128
Change in other noncurrent liabilities	(36,634)	(15,137)
Net cash provided by operating activities	1,123,116	913,215
Investing activities		
Utility capital/construction expenditures	(1,122,269)	(967,331)
Merricourt refund	101,261	-
Merricourt deposit	(90,833)	-
Allowance for equity funds used during construction	26,850	26,286
Purchase of investments in external decommissioning fund	(1,226,504)	(3,001,198)
Proceeds from the sale of investments in external decommissioning fund	1,226,491	3,006,616
Investment in WYCO Development LLC	(961)	(2,905)
Change in restricted cash	46	(44)
Other investments	(3,964)	4,150
Net cash used in investing activities	(1,089,883)	(934,426)
Financing activities		
Proceeds from (repayment of) short-term borrowings, net	189,600	(330,000)

Proceeds from issuance of long-term	-	544,205
Repayment of long-term debt, including reacquisition premiums	(1,741)	(25,860)
Proceeds from issuance of common stock	3,789	4,294
Dividends paid	(231,715)	(212,387)
Net cash used in financing activities	(40,067)	(19,748)
Net decrease in cash and cash equivalents	(6,834)	(40,959)
Cash and cash equivalents at beginning of period	108,437	115,648
Cash and cash equivalents at end of period	$101,603	$74,689
Supplemental disclosure of cash flow information:		
Cash paid for interest, net of amounts capitalized	$(266,559)	$(254,113)
Cash received (paid) for income taxes, net	54,993	(7,831)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$120,558	$53,871
Issuance of common stock for reinvested dividends and 401(k) plans	$37,680	$32,261

See Notes to Consolidated Financial Statements

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)
(amounts in thousands of dollars)

	June 30, 2011	Dec. 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$101,603	$108,437
Accounts receivable, net	679,560	718,474
Accrued unbilled revenues	590,855	708,691
Inventories	484,772	560,800
Regulatory assets	381,457	388,541
Derivative instruments	53,832	54,079
Prepayments and other	186,884	193,621
Total current assets	2,478,963	2,732,643
Property, plant and equipment, net	21,513,539	20,663,082
Other assets		
Nuclear decommissioning fund and other investments	1,517,058	1,476,435
Regulatory assets	2,160,780	2,151,460
Derivative instruments	169,067	184,026
Other	163,817	180,044
Total other assets	4,010,722	3,991,965
Total assets	$28,003,224	$27,387,690
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$53,927	$55,415
Short-term debt	656,000	466,400
Accounts payable	957,521	979,750
Regulatory liabilities	170,655	156,038
Taxes accrued	189,564	254,320
Accrued interest	165,313	163,907
Dividends payable	127,040	122,847
Derivative instruments	39,990	61,745
Other	278,749	276,111
Total current liabilities	2,638,759	2,536,533
Deferred credits and other liabilities		
Deferred income taxes	3,665,418	3,390,027
Deferred investment tax credits	89,777	92,937
Regulatory liabilities	1,143,485	1,179,765
Asset retirement obligations	1,277,785	969,310
Derivative instruments	272,481	285,986
Customer advances	258,161	269,087
Pension and employee benefit obligations	828,500	962,767
Other	225,757	249,635

Total deferred credits and other liabilities	7,761,364	7,399,514
Commitments and contingent liabilities		
Capitalization		
Long-term debt	9,263,556	9,263,144
Preferred stockholders' equity	104,980	104,980
Common stock – $2.50 par value per share	1,211,356	1,205,834
Additional paid in capital	5,261,687	5,229,075
Retained earnings	1,812,505	1,701,703
Accumulated other comprehensive loss	(50,983)	(53,093)
Total common stockholders' equity	8,234,565	8,083,519
Total liabilities and equity	$28,003,224	$27,387,690

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

	Common Stock Issued					
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity
Three Months Ended June 30, 2011 and 2010						
Balance at March 31, 2010	459,215	$ 1,148,038	$ 4,784,152	$ 1,472,308	$ (48,627)	$ 7,355,871
Net income				139,776		139,776
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $321					456	456
Net derivative instrument fair value changes, net of tax of $(2,725)					(3,807)	(3,807)
Unrealized gain - marketable securities, net of tax of $(74)					(107)	(107)
Comprehensive income for the period						136,318
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(117,027)		(117,027)
Issuances of common stock	412	1,031	7,612			8,643
Share-based compensation			9,077			9,077
Balance at June 30, 2010	459,627	$ 1,149,069	$ 4,800,841	$ 1,493,997	$ (52,085)	$ 7,391,822
Balance at March 31, 2011	484,165	$ 1,210,411	$ 5,241,533	$ 1,781,386	$ (51,847)	$ 8,181,483
Net income				158,762		158,762
Changes in unrecognized					754	754

amounts of pension and retiree medical benefits, net of tax of $525						
Net derivative instrument fair value changes, net of tax of $100					110	110
Comprehensive income for the period						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

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

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders' Equity
	Shares	Par Value				
Six Months Ended June 30, 2011 and 2010						
Balance at Dec. 31, 2009	457,509	$ 1,143,773	$ 4,769,980	$ 1,419,201	$ (49,709)	$ 7,283,245
Net income				306,894		306,894
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $616					875	875
Net derivative instrument fair value changes during the period, net of tax of $(2,265)					(3,155)	(3,155)
Unrealized gain - marketable securities, net of tax of $(66)					(96)	(96)
Comprehensive income for the period						304,518
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(229,978)		(229,978)
Issuances of common stock	2,118	5,296	15,633			20,929
Share-based compensation			15,228			15,228
Balance at June 30, 2010	459,627	$ 1,149,069	$ 4,800,841	$ 1,493,997	$ (52,085)	$ 7,391,822
Balance at Dec. 31, 2010	482,334	$ 1,205,834	$ 5,229,075	$ 1,701,703	$ (53,093)	$ 8,083,519
Net income				362,331		362,331
Changes in unrecognized amounts					1,548	1,548

of pension and retiree medical benefits, net of tax of $1,076						
Net derivative instrument fair value changes during the period, net of tax of $392					512	512
Unrealized loss - marketable securities, net of tax of $35					50	50
Comprehensive income for the period						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

See Notes to Consolidated Financial Statements

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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 (collectively, Xcel Energy) as of June 30, 2011 and Dec. 31, 2010; the results of its operations and changes in stockholders' equity for the three and six months ended June 30, 2011 and 2010; and its cash flows for the six months ended June 30, 2011 and 2010. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Management has also evaluated the impact of events occurring after June 30, 2011 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, 2010 balance sheet information has been derived from the audited 2010 consolidated financial statements included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2010. 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 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, 2010, filed with the SEC on Feb. 28, 2011. 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, 2010, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

2. Accounting Pronouncements

Recently Issued

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 additional guidance for fair value measurements. These updates to the FASB Accounting Standards Codification (ASC or Codification) include 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 and disclosures regarding the sensitivity of Level 3 measurements to changes in valuation model inputs. These updates to the Codification are effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy does not expect the implementation of this guidance to have a material impact on its consolidated financial statements.

Comprehensive Income — In June 2011, the FASB issued Comprehensive Income (Topic 220) — Presentation of Comprehensive Income (ASU No. 2011-05), which updates the Codification to require the presentation of the components of net income, the components of other comprehensive income (OCI) and total comprehensive income in either a single continuous statement of comprehensive income or in two separate, but consecutive 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 updates to the Codification are effective for interim and annual periods beginning after Dec. 15, 2011. Xcel Energy does not expect the implementation of this 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, 2011	Dec. 31, 2010
Accounts receivable, net		
Accounts receivable	$ 730,694	$ 773,037
Less allowance for bad debts	(51,134)	(54,563)
	$ 679,560	$ 718,474
Inventories		
Materials and supplies	$ 204,008	$ 196,081
Fuel	180,788	188,566
Natural gas	99,976	176,153
	$ 484,772	$ 560,800
Property, plant and equipment, net		
Electric plant	$ 26,059,167	$ 24,993,582
Natural gas plant	3,520,658	3,463,343
Common and other property	1,586,265	1,555,287
Plant to be retired (a)	199,315	236,606
Construction work in progress	1,143,591	1,186,433
Total property, plant and equipment	32,508,996	31,435,251
Less accumulated depreciation	(11,378,696)	(11,068,820)
Nuclear fuel	1,968,017	1,837,697
Less accumulated amortization	(1,584,778)	(1,541,046)
	$ 21,513,539	$ 20,663,082

(a) In 2009, in accordance with the Colorado Public Utilities Commission (CPUC)'s approval of PSCo's 2007 Colorado resource plan and subsequent rate case decisions, PSCo agreed to early retire its Cameo Units 1 and 2, Arapahoe Units 3 and 4 and Zuni Units 1 and 2 facilities. In 2010, in response to the Clean Air Clean Jobs Act (CACJA), the CPUC approved the early retirement of Cherokee Units 1, 2 and 3, Arapahoe Unit 3 and Valmont Unit 5 between 2011 and 2017. 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, 2010 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 2006 federal income tax return expired in August 2010. The statute of limitations applicable to Xcel Energy's 2007 federal income tax return expires in September 2011. The Internal Revenue Service (IRS) commenced an examination of tax years 2008 and 2009 in the third quarter of 2010. As of June 30, 2011, the IRS had not proposed any material adjustments to tax years 2008 and 2009.

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, 2011, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions are as follows:

State	Year
Colorado	2006

Minnesota	2007
Texas	2006
Wisconsin	2006

As of June 30, 2011, there were no state income tax audits in progress.

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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.

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

(Millions of Dollars)	June 30, 2011	Dec. 31, 2010
Unrecognized tax benefit — Permanent tax positions	$6.8	$5.9
Unrecognized tax benefit — Temporary tax positions	34.0	34.6
Unrecognized tax benefit balance	$40.8	$40.5

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, 2011	Dec. 31, 2010
NOL and tax credit carryforwards	$(38.3)	$(38.0)

The increase in the unrecognized tax benefit balance of $0.1 million from March 31, 2011 to June 30, 2011 and $0.3 million from Dec. 31, 2010 to June 30, 2011 was due primarily to the addition of uncertain tax positions related to current and prior years' activity. Xcel Energy's amount of unrecognized tax benefits could significantly change in the next 12 months as the IRS audit progresses and state audits resume. As the IRS examination moves closer to completion, it is reasonably possible that the amount of unrecognized tax benefits could decrease up to approximately $27 million.

The payable for interest related to unrecognized tax benefits is substantially offset by the interest benefit associated with NOL and tax credit carryforwards. The payables for interest related to unrecognized tax benefits at June 30, 2011 and Dec. 31, 2010 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of June 30, 2011 or Dec. 31, 2010.

5. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 13 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2010 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference.

NSP-Minnesota

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

NSP-Minnesota Electric Rate Case — In November 2010, NSP-Minnesota filed a request with the MPUC to increase annual electric rates in Minnesota for 2011 by approximately $150 million, or an increase of 5.62 percent. The rate filing is based on a 2011 forecast test year and included a requested return on equity (ROE) of 11.25 percent, an electric rate base of approximately $5.6 billion and an equity ratio of 52.56 percent. NSP-Minnesota requested an additional increase of $48.3 million or 1.81 percent effective Jan. 1, 2012, to address certain known and measurable

cost increases in 2012.

The MPUC approved an interim rate increase of $123 million, subject to refund, effective Jan. 2, 2011. The interim rates will remain in effect until the MPUC makes its final decision on the case.

In May 2011, NSP-Minnesota revised its rate increase request to approximately $126.4 million or 4.7 percent for 2011, largely due to a revised requested ROE of 10.85 percent. NSP-Minnesota also reduced its requested increase for 2012 to $44.7 million. The Department of Energy Resource (DOER) (formerly the Office of Energy Security or OES) recommended a $58 million rate increase, based on a 10.37 percent ROE and a $31 million adjustment for income taxes related to bonus depreciation. The Office of Attorney General (OAG) and the Xcel Large Industrial Group recommended a rate reduction and refund of depreciation reserves and reductions to or elimination of incentive compensation costs. The OAG recommended refunding the liability associated with retiree medical benefits.

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At the hearings in June 2011, NSP-Minnesota resolved differences with the DOER on income taxes and sales forecast. NSP-Minnesota also made an adjustment to bad debt and incentive compensation expense. As a result of these adjustments, NSP-Minnesota revised its requested rate increase to $122.8 million. The DOER revised its recommended rate increase to approximately $84.7 million, reflecting these same changes. The primary differences between the NSP-Minnesota requested rate increase and the DOER updated recommendation are associated with the ROE and incentive compensation issues. The DOER recommended an additional rate increase of $34 million in 2012. In the second quarter of 2011, NSP-Minnesota recorded a provision for revenue subject to refund of approximately $15 million, which should be sufficient to address an outcome that is more consistent with the DOER position than NSP-Minnesota's position on various issues. NSP-Minnesota cannot predict the ultimate outcome of this pending regulatory proceeding. The MPUC decision is expected in the fourth quarter of 2011.

Electric, Purchased Gas and Resource Adjustment Clauses

Conservation Improvement Program (CIP) Rider — CIP expenses are recovered through a charge embedded in base rates and a rider that is adjusted annually. Under the 2010 electric CIP rider request filed in October 2010, NSP-Minnesota estimates recovery of $66.7 million through the rider during the November 2010 to September 2011 timeframe. This is in addition to an expected $48.1 million recovered through the conservation cost recovery charge component of base rates. NSP-Minnesota estimates recovery of approximately $18.6 million through the natural gas CIP rider filed in November 2010, during the December 2010 to September 2011 timeframe. This is in addition to an expected $3.0 million recovered through the conservation cost recovery charge component of base rates. Assuming MPUC approval, NSP-Minnesota estimates it will recover a total of approximately $136.4 million associated with CIP programs in 2011.

In April 2011, NSP-Minnesota filed its annual rider petitions requesting recovery of approximately $84.8 million of electric CIP expenses and financial incentives and $4.5 million of natural gas CIP expenses and financial incentives to be recovered during the October 2011 through September 2012 timeframe. This proposed recovery through the riders is in addition to an estimated $52.6 million and $3.8 million to be recovered through the electric and gas conservation cost recovery charge component of base rates, respectively. Assuming MPUC approval, NSP-Minnesota estimates it will recover a total of approximately $145.7 million associated with CIP programs in 2012.

Renewable Development Fund (RDF) Rider — The MPUC has approved an RDF rider that allows annual adjustments to retail electric rates to provide for the recovery of RDF program and project expenses. The primary components of RDF costs are legislatively mandated expenses such as renewable energy production incentive payments, RDF grant project payments, and RDF program administrative costs. In October 2010, NSP-Minnesota filed its annual request to recover $19.2 million in expenses for 2011. In May 2011, the MPUC approved recovery of the costs requested.

Annual Automatic Adjustment Report for 2009/2010 — In September 2010, NSP-Minnesota filed its annual electric and natural gas automatic adjustment reports for July 1, 2009 through June 30, 2010. During that time period, $749.5 million in fuel and purchased energy costs were recovered from Minnesota electric customers through the fuel clause adjustment. In addition, approximately $354.5 million of purchased natural gas and transportation costs were recovered from Minnesota natural gas customers through the purchased gas adjustment. The DOER recommended approval of the 2009/2010 gas report in June 2011, and the report is pending MPUC action. The electric report is pending DOER comments and MPUC action.

The MPUC approved the 2008/2009 gas annual automatic adjustment report in March 2011. Approval of the 2008/2009 electric report is pending DOER comments and MPUC action.

Pending and 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. The rate filing is based on a 2011 forecast test year and includes a requested ROE of 11.25 percent, an electric rate base of approximately $328 million and an equity ratio of 52.56 percent. NSP-Minnesota requested an additional increase of $4.2 million, or 2.6 percent, effective Jan. 1, 2012, to address certain known and measurable cost increases in 2012.

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 increase in 2012, due to the termination of the Merricourt wind project.

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The NDPSC approved an interim rate increase of approximately $17.4 million, subject to refund, effective Feb. 18, 2011. The interim rates will remain in effect until the NDPSC makes its final decision on the case, which is anticipated in the first quarter of 2012. The remaining schedule is listed below:

- Intervenor direct testimony due Aug. 18, 2011;
- Rebuttal testimony due Sept. 20, 2011; and
- Evidentiary hearings due Oct. 18-21, 2011.

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

NSP-Minnesota South Dakota 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. Net of current automatic recovery mechanisms, the requested increase was $13.9 million. The request is 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. NSP-Minnesota also requested approval of a nuclear cost recovery rider to recover the actual investment cost of the Monticello life cycle management and enhanced power uprate project that is not reflected in the test year.

NSP-Wisconsin

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

NSP-Wisconsin 2011 Electric and Gas Rate Case — In June 2011, NSP-Wisconsin filed a request with the PSCW to increase electric rates approximately $29.2 million, or 5.1 percent and natural gas rates approximately $8.0 million, or 6.6 percent effective Jan. 1, 2012. The rate filing is based on a 2012 forecast test year and includes a requested ROE of 10.75 percent, and an equity ratio of 52.54 percent. The rate base in 2012 is forecast to be approximately $718 million for the electric utility and $84 million for the natural gas utility. A PSCW decision is anticipated in the fourth quarter of 2011.

PSCo

Pending and Recently Concluded Regulatory Proceedings — CPUC

PSCo 2010 Gas Rate Case — In December 2010, PSCo filed a request with the CPUC to increase Colorado retail gas rates by $27.5 million on an annual basis. In March 2011, PSCo revised its requested rate increase to $25.6 million. The revised request was based on a 2011 forecast test year, a 10.90 percent ROE, a rate base of $1.1 billion and an equity ratio of 57.10 percent. PSCo proposed recovering $23.2 million of test year capital and operating and maintenance (O&M) expenses associated with several pipeline integrity costs plus an amortization of similar costs that have been accumulated and deferred since the last rate case in 2006. PSCo also proposed removing the earnings on gas in underground storage from base rates.

In May 2011, PSCo filed a comprehensive settlement with CPUC Staff and the Colorado Office of Consumer Counsel (OCC) to increase rates by $10.9 million, to institute rider recovery of future integrity management costs, and to remove underground storage from base rates and recover those costs in the Gas Cost Adjustment (GCA) rider. The GCA recovery of the return on gas in storage is expected to recover another $10 million of annual incremental revenue, subject to adjustment to actual costs. Rates were set on a test year ending June 30, 2011 with an equity ratio of 56 percent and an ROE of 10.1 percent. New base rates and the GCA recovery are expected to go into effect in September 2011. The rider for integrity management costs is expected to go into effect on Jan. 1, 2012 and is

expected to recover an estimated $13 million of incremental revenue in 2012. In July 2011, the presiding hearing commissioner approved the settlement with certain modifications and PSCo subsequently filed exceptions to the recommended decision.

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

PSCo Wholesale Rate Case — In February 2011, PSCo filed a request with the FERC to change Colorado wholesale electric customer rates to formula based rates with an expected increase of $16.1 million annually for 2011. The request was based on a 2011 forecast test year, a 10.9 percent ROE, a wholesale rate base of $407.4 million and an equity ratio of 57.1 percent. Under the proposal, the formula rate would be estimated annually and then would be trued up to actual costs after the conclusion of the year. The primary drivers of the revenue deficiency are the recently acquired Blue Spruce Energy Center and Rocky Mountain Energy Center generating units, as well as the costs of early retirement of certain coal plants under the CACJA emissions reduction plan, all of which were approved by the CPUC in late 2010. In April 2011, the FERC suspended the effective date five months, allowing the rates to be placed into effect on Sept. 10, 2011, subject to refund and set the request for settlement procedures.

Electric, Purchased Gas and Resource Adjustment Clauses

Renewable Energy Credit (REC) Sharing Settlement — In May 2010, the CPUC approved a settlement on the treatment of margins associated with sales of Colorado RECs that are bundled with energy into California. The settlement establishes a pilot program and defines certain margin splits during this pilot period. The settlement provides that margins would be shared based on the following allocations:

Margin	Customers		PSCo		Carbon Offsets	
Less than $10 million	50	%	40	%	10	%
$10 million to $30 million	55		35		10	
Greater than $30 million	60		30		10	

Amounts designated as carbon offsets are recorded as a regulatory liability until carbon offset-related expenditures are incurred. Carbon offsets are capped at $10 million, with the remaining 10 percent going to customers after the cap is reached. The unanimous settlement also clarified that margins associated with RECs bundled with Colorado energy would be shared 20 percent to PSCo and 80 percent to customers. Margins associated with sales of unbundled stand-alone RECs without energy would be credited 100 percent to customers.

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 REC trading margins that allows the customers' share of the margins through the end of the pilot period, approximately $54 million, to be netted against the renewable energy standard adjustment (RESA) regulatory asset balance. At June 30, 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

In June 2011, PSCo filed an application for permanent treatment of Colorado RECs that are bundled with energy into California. The application is seeking margin sharing of 30 percent to PSCo and 70 percent to customers for deliveries outside of California and 40 percent to PSCo and 60 percent to customers for deliveries inside of California. PSCo also proposed that sales of RECs bundled with on-system energy be aggregated with other trading margins and shared 20 percent to PSCo and 80 percent to customers. The CPUC has indicated a desire to expedite the matter and a decision is expected in the fourth quarter of 2011.

SPS

Pending and Recently Concluded Regulatory Proceedings — New Mexico Public Regulation Commission (NMPRC)

SPS New Mexico Electric Rate Case — In February 2011, SPS filed a request in New Mexico with the NMPRC seeking to increase New Mexico electric rates approximately $19.9 million. The rate filing is based on a 2011 test year adjusted for known and measurable changes for 2012, a requested ROE of 11.25 percent, an electric rate base of $390.3 million and an equity ratio of 51.11 percent. Rates are expected to go into effect during the first quarter of 2012.

The New Mexico Attorney General (NMAG) has filed a motion to dismiss the rate case or to toll the suspension period of rates, and the NMPRC Staff has also filed a motion to reject the filing and for SPS to file additional information on the grounds that SPS' information supporting its 2011 test year is incomplete. SPS has filed a response asserting that SPS' filing is complete and requesting the NMPRC to deny the NMAG's motion. The NMPRC has not yet acted on the motion. The date for SPS to respond to the Staff's motion has not yet been established.

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6. Commitments and Contingent Liabilities

Except to the extent noted below and in Note 5 to the consolidated financial statements in this Quarterly Report on Form 10-Q, the circumstances set forth in Notes 13, 14 and 15 to the consolidated financial statements included in Xcel Energy Inc.'s Annual Report on Form 10-K for the year ended Dec. 31, 2010, 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.

Commitments

Variable Interest Entities — The accounting guidance for consolidation of variable interest entities requires enterprises to consider the activities that most significantly impact an entity's financial performance, and power to direct those activities, when determining whether an enterprise is a variable interest entity's primary beneficiary.

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.

Xcel Energy has evaluated each of these variable interest entities for possible consolidation, including review of qualitative factors such as the length and terms of the contract, control over O&M expenses, historical and estimated future fuel and electricity prices, and financing activities. 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. Xcel Energy had approximately 3,973 megawatts (MW) and 4,101 MW of capacity under long-term purchased power agreements as of June 30, 2011 and Dec. 31, 2010 with entities that have been determined to be variable interest entities. These agreements have expiration dates through the year 2033.

Low-Income Housing Limited Partnerships — Eloigne Company (Eloigne) and NSP-Wisconsin have entered into limited partnerships for the construction and operation of affordable rental housing developments which qualify for low-income housing tax credits. Xcel Energy Inc. has determined Eloigne and NSP-Wisconsin's low-income housing limited partnerships to be variable interest entities primarily due to contractual arrangements within each limited partnership that establish sharing of ongoing voting control and profits and losses that does not consistently align with the partners' proportional equity ownership. Xcel Energy Inc. has determined that Eloigne and NSP-Wisconsin have the power to direct the activities that most significantly impact these entities' economic performance, and therefore Xcel Energy Inc. consolidates these limited partnerships in its consolidated financial statements.

Amounts reflected in Xcel Energy's consolidated balance sheets for the Eloigne and NSP-Wisconsin low-income housing limited partnerships include the following:

(Thousands of Dollars)	June 30, 2011	Dec. 31, 2010
Current assets	$ 3,594	$ 3,794
Property, plant and equipment, net	94,728	97,602
Other noncurrent assets	8,176	8,236
Total assets	$ 106,498	$ 109,632
Current liabilities	$ 10,622	$ 11,884

Mortgages and other long-term debt payable	52,715	53,195
Other noncurrent liabilities	8,220	8,333
Total liabilities	$ 71,557	$ 73,412

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Guarantees — Xcel Energy Inc. provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy Inc. guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy Inc.'s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy Inc. limit the exposure of Xcel Energy Inc. to a maximum amount stated in the guarantees. As of June 30, 2011 and Dec. 31, 2010, Xcel Energy Inc. had no assets held as collateral relating to its guarantees and bond indemnities.

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

(Millions of Dollars)	June 30, 2011	Dec. 31, 2010
Guarantees issued and outstanding	$ 155.0	$ 155.7
Known exposure under these guarantees	17.9	18.0
Bonds with indemnity protection	31.1	32.5

Environmental Contingencies

Xcel Energy Inc. and its subsidiaries have been, or are currently, involved with the cleanup of contamination from certain hazardous substances at several sites. In many situations, the subsidiary involved believes it will recover some portion of these costs through insurance claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties (PRPs) and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy Inc. and its subsidiaries, which are normally recovered through the rate regulatory process. To the extent any costs are not recovered through the options listed above, Xcel Energy would be required to recognize an expense.

Site Remediation — The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regarding the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances to the environment. Xcel Energy must pay all or a portion of the cost to remediate sites where past activities of its subsidiaries or other parties have caused environmental contamination. Environmental contingencies could arise from various situations, including sites of former manufactured gas plants (MGPs) operated by Xcel Energy Inc. subsidiaries, predecessors, or other entities; and third-party sites, such as landfills, for which Xcel Energy Inc. is alleged to be a PRP that sent hazardous materials and wastes. At June 30, 2011 and Dec. 31, 2010, the liability for the cost of remediating these sites was estimated to be $107.1 million and $104.0 million, respectively, of which $6.0 million and $5.7 million, respectively, was considered to be a current liability.

MGP Sites

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

In 2002, the Ashland site was placed on the National Priorities List. In 2009, the Environmental Protection Agency (EPA) issued its proposed remedial action plan (PRAP). The EPA issued its Record of Decision (ROD) in September 2010, which documents the remedy that the EPA has selected for the cleanup of the site. The EPA has estimated the cost for its selected cleanup is between $83 million and $97 million. The EPA has stated that this cost estimate is expected to be within plus 50 percent to minus 30 percent of the actual project costs.

In April 2011, the EPA issued special notice letters identifying several entities, including NSP-Wisconsin, as PRPs, responsible for future cleanup 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 cleanup. The special notice established a 60 day moratorium against enforcement action by the EPA. On June 30, 2011, NSP-Wisconsin submitted a settlement offer to EPA related to the future cleanup of the site and performance of a pilot study in Chequamegon Bay to demonstrate the effectiveness of a wet dredge full scale sediment remedy at the site. On July 14, 2011, the EPA informed NSP-Wisconsin and the other PRPs that it was rejecting all of their individual offers and that the EPA had determined it would not extend the enforcement moratorium by another 60 days, such that the EPA can now choose to initiate enforcement actions at any time. Despite this decision, the EPA also indicated a willingness to continue settlement negotiations with NSP-Wisconsin.

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NSP-Wisconsin's potential liability, the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable until after negotiations or litigation with the EPA and other PRPs at the site 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. NSP-Wisconsin has recorded a liability of $97.5 million based upon potential remediation and design costs together with estimated outside legal and consultant costs.

NSP-Wisconsin has deferred, as a regulatory asset, the costs accrued for the Ashland site 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 recovery in NSP-Wisconsin rates of all remediation costs incurred at the Ashland site and has authorized recovery of similar remediation costs incurred by other Wisconsin utilities for remediation of manufactured gas plants. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process. Under an existing PSCW policy with respect to recovery of remediation costs for manufactured gas plants, utilities have recovered costs amortized over a four to six year period. The PSCW has not allowed utilities to recover interest on the unamortized balance.

In addition, in 2003, the Wisconsin Supreme Court rendered a ruling that reopens the possibility that NSP-Wisconsin may be able to recover a portion of the remediation costs from its insurance carriers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers.

In addition to potential liability for remediation, NSP-Wisconsin may also have potential liability for natural resource damages at the Ashland site. NSP-Wisconsin has recorded an estimate of its potential liability based upon its best estimate of potential exposure.

Owen Park MGP Site — The Wisconsin Department of Natural Resources (WDNR) requested that NSP-Wisconsin investigate the Owen Park site on the west bank of the Chippewa River in Eau Claire, Wis. It is believed that this site was previously an MGP site prior to current ownership by the City of Eau Claire. The WDNR has indicated that it believes NSP-Wisconsin may have successor liability for the Owen Park site.

In response to the WDNR's request, NSP-Wisconsin is performing an ongoing site investigation, and has concluded that materials typically associated with the operation of MGPs are present in soils and groundwater at the site. Information obtained from this ongoing investigation indicates some site remediation may be required. The ultimate scope and costs of such remediation are not determinable at this time, and will not be fully determinable until a remediation action plan is submitted and approved by the WDNR. It is anticipated, however, that remediation costs will not have a material adverse effect on Xcel Energy's consolidated results of operations, cash flow or financial position.

Asbestos Removal — Some of Xcel Energy's facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or removed. Xcel Energy has recorded an estimate for final removal of the asbestos as an asset retirement obligation (ARO). See additional discussion of AROs in Note 14 of the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2010. It may be necessary to remove some asbestos to perform maintenance or make improvements to other equipment. The cost of removing asbestos as part of other work is not expected to be material and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

Other Environmental Requirements

EPA Greenhouse Gas (GHG) Endangerment Rulemaking — In December 2009, the EPA issued its "endangerment" finding that GHG emissions endanger public health and welfare. In January 2011, new EPA permitting requirements

became effective for GHG emissions of new and modified large stationary sources, which are applicable to the construction of new power plants or power plant modifications that increase emissions above a certain threshold. The EPA plans to propose GHG regulations applicable to emissions from existing power plants under the Clean Air Act (CAA). In June 2011, the EPA announced that they have delayed the proposal date to September 2011, but still plan on issuing final rules in May 2012.

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Cross State Air Pollution Rule (CSAPR) — On July 7, 2011, the EPA issued its CSAPR. The rule, previously called the Transport Rule, addresses long range transport of particulate matter and ozone by requiring reductions in sulfur dioxide (SO2) and nitrogen oxide (NOx) from utilities located in the eastern half of the U.S. For Xcel Energy, the rule applies to Minnesota, Wisconsin and Texas. The CSAPR sets more stringent requirements than the proposed Transport Rule and, in contrast to that proposal, specifically requires plants in Texas to reduce their SO2 and annual NOx emissions. The rule creates an emissions trading program, although interstate trading under the rule will be significantly restricted. Xcel Energy may comply by either reducing emissions, purchasing allowances, or a combination of the two. The CSAPR is a final rule and requires compliance beginning in 2012.

Xcel Energy is still evaluating compliance options. At this time, Xcel Energy believes that the CSAPR will likely require the installation of additional emission controls on some of SPS' coal-fired electric generating units. Xcel Energy also anticipates that NSP-Minnesota and NSP-Wisconsin will ultimately comply with the rule through execution of their existing resource and emission control plans as well as through allowance purchases and other activities. Because the CSAPR requires compliance in 2012, SPS, NSP-Minnesota and NSP-Wisconsin may be required to take additional short-term action (including redispatching its system to reduce coal plant operating hours) in order to decrease emissions from its facilities prior to the installation of emission controls. Xcel Energy is still evaluating our short-term compliance strategy. Xcel Energy believes the cost of any required capital investment, allowance purchases or redispatch costs will be recoverable from customers.

Clean Air Interstate Rule (CAIR) — In 2005, the EPA issued the CAIR to further regulate SO2 and NOx emissions. In 2008, the U.S. Court of Appeals for the District of Columbia vacated and remanded the CAIR, but subsequently allowed the CAIR to continue into effect pending the EPA's adoption of a new rule that addressed the deficiencies found by the court. CSAPR replaces the CAIR, and will be applicable to our plants beginning in 2012. The CAIR applies to Texas and Wisconsin. The CAIR does not apply in Minnesota because the court specifically found that the EPA had not adequately justified the application of the CAIR to Minnesota.

Under the CAIR's cap and trade structure, companies can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. The remaining scheduled capital investments for NOx controls in the SPS region are estimated at $16.4 million. These capital investments should assist SPS in complying with the CSAPR once it becomes effective in 2012. At June 30, 2011, the estimated annual CAIR NOx allowance cost for SPS was $0.3 million. At June 30, 2011, the estimated annual CAIR NOx allowance cost for NSP-Wisconsin was $0.1 million. The CSAPR will establish a new emissions market for SO2 and NOx, and Xcel Energy does not yet have enough information to estimate the cost of future CSAPR allowance purchases. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers.

Electric Generating Unit (EGU) Maximum Achievable Control Technology (MACT) Rule — In 2005, the EPA issued the Clean Air Mercury Rule (CAMR), which regulated mercury emissions from power plants. In February 2008, the U.S. Court of Appeals for the District of Columbia vacated the CAMR, which impacted federal CAMR requirements, but not necessarily state-only mercury legislation and rules.

In March 2011, the EPA issued the proposed EGU MACT designed to address emissions of mercury and other hazardous air pollutants for coal-fired utility units greater than 25 MW. The EPA intends to issue the final rule by November 2011. Xcel Energy anticipates that the EPA will require affected facilities to demonstrate compliance within three to four years.

Colorado Mercury Regulation — Colorado's mercury regulations require mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by the end of 2011. The expected cost estimate for the Pawnee Generating Station is $2.3 million for capital costs with an annual estimate of $1.4 million for sorbent

expense. PSCo has evaluated the Colorado mercury control requirements for its other units in Colorado and believes that, under the current regulations, no further controls will be required other than the planned controls at the Pawnee Generating Station. The Pawnee mercury controls are included in the CACJA plan.

Minnesota Mercury Legislation — In 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For NSP-Minnesota, the Act covers units at the A.S. King and Sherco generating facilities. NSP-Minnesota installed and is operating continuous mercury emission monitoring systems at these generating facilities.

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In November 2008, the MPUC approved the implementation of the Sherco Unit 3 and A.S. King mercury emission reduction plans. A sorbent injection control system was installed at Sherco Unit 3 in December 2009 and at A.S. King in December 2010. In 2010, NSP-Minnesota collected the revenue requirements associated with these projects through the mercury cost reduction (MCR) rider. In the 2010 Minnesota electric general rate case, NSP-Minnesota proposed moving the costs of these projects into base rates as part of the interim rates effective on Jan. 2, 2011. Concurrent with the implementation of interim rates, the MCR rider was reduced to zero.

In December 2009, NSP-Minnesota filed its mercury control plan at Sherco Units 1 and 2 with the MPUC and the Minnesota Pollution Control Agency (MPCA). In October 2010, the MPUC approved the plan, which will require installation of mercury controls on Sherco Units 1 and 2 by the end of 2014. NSP-Minnesota has incurred $1.5 million in study costs to date and spent $0.6 million through Dec. 31, 2010 for testing and studying of technologies. At June 30, 2011, the estimated annual testing and study cost is $0.5 million. NSP-Minnesota projects installation costs of $12.0 million for the two units and O&M expense of $10.0 million per year beginning in 2014.

Industrial Boiler (IB) MACT Rules — In March 2011, the EPA finalized IB MACT rules to regulate boilers and process heaters fueled with coal, biomass and liquid fuels. The EPA has announced that it will be reconsidering portions of these rules. In its current form, the IB MACT rule would apply to only one Xcel Energy plant in Wisconsin.

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 (U.S.). Xcel Energy generating facilities in several states will be subject to BART requirements. Individual states are required to identify the facilities located in their states that will have to reduce SO2, NOx and particulate matter emissions under BART and then set emissions limits for those facilities.

PSCo

In 2006, the Colorado Air Quality Control Commission 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 Colorado Air Quality Commission approved a revised Regional Haze BART/Reasonable Further Progress state implementation plan (SIP) incorporating the Colorado CACJA emission reduction plan. In accordance with Colorado law, the SIP passed the Colorado general assembly, was signed by the governor and was submitted to the EPA. PSCo anticipates that for those plants included in the Colorado CACJA emission reduction plan, the SIP will satisfy regional haze requirements. The Colorado SIP, however, must be approved by the EPA. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2012 and 2017.

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. Four 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

NSP-Minnesota submitted its BART alternatives analysis for Sherco Units 1 and 2 in 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. The MPCA completed their determination and proposed SO2 and NOx limits in the draft SIP that are equivalent to the

reductions made under CAIR. Neither the MPCA nor the EPA has yet made a determination that that the compliance with the CSAPR is better than BART or that compliance with the CSAPR will fulfill the obligation to comply with BART.

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 visibility impairment and, if so, whether the level of controls proposed by MPCA is appropriate.

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The MPCA determined that this certification does not alter the proposed SIP. The SIP proposes BART controls for the Sherco generating facilities that are designed to improve visibility in the national parks, but does not require selective catalytic reduction (SCR) on Units 1 and 2. The MPCA concluded that the minor visibility benefits derived from SCR do not outweigh the substantial costs. In December 2009, the MPCA Citizens Board approved the SIP, which has been submitted to the EPA for approval. In June 2011, the EPA provided comments to the MPCA on the SIP, stating the EPA's preliminary review indicates that SCR controls should be added to Sherco Units 1 and 2, and inviting further comment from the MPCA. It is not yet known what the final requirements of the SIP will be. Until the EPA takes final action on the SIP, the total cost of compliance cannot be estimated.

Federal Clean Water Act (CWA Section 316 (b)) — The federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts to aquatic species. In April 2011, the EPA published the proposed rule that was modified to address earlier court decisions. The proposed rule sets prescriptive standards for minimization of aquatic species impingement but leaves entrainment reduction requirements at the discretion of the permit writer and the regional EPA office. Xcel Energy is evaluating the proposed rule, including possible additional capital and operating expenses, and plans to offer comments to the EPA. Due to the uncertainty of the final regulatory requirements, it is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time.

As part of NSP-Minnesota's 2009 CWA permit renewal for the Black Dog plant, the MPCA required that the plant submit a plan for compliance with the CWA. The compliance plan was submitted for MPCA review and approval in April 2010. The MPCA is currently reviewing the proposal in consultation with the EPA. Xcel Energy anticipates a decision on the plan by the end of 2011.

Proposed Coal Ash Regulation — Xcel Energy's operations generate hazardous wastes that are subject to the Federal Resource Recovery and Conservation Act and comparable state laws that impose detailed requirements for handling, storage, treatment and disposal of hazardous waste. In June 2010, the EPA published a proposed rule seeking comment on whether to regulate coal combustion byproducts (often referred to as coal ash) as hazardous or nonhazardous waste. Coal ash is currently exempt from hazardous waste regulation. If the EPA ultimately issues a final rule under which coal ash is regulated as hazardous waste, Xcel Energy's costs associated with the management and disposal of coal ash would significantly increase, and the beneficial reuse of coal ash would be negatively impacted. The EPA has not announced a planned date for a final rule. The timing, scope and potential cost of any final rule that might be implemented are not determinable at this time.

PSCo Notice of Violation (NOV) — In 2002, PSCo received an NOV from the EPA alleging violations of the New Source Review (NSR) requirements of the CAA at the Comanche Station and Pawnee Station in Colorado. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid to late 1990s should have required a permit under the NSR process. PSCo believes it has acted in full compliance with the CAA and NSR process. PSCo also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. PSCo disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

Cunningham Compliance Order — In February 2010, SPS received a draft compliance order from the New Mexico Environment Department (NMED) for Cunningham Station. In the draft order, NMED alleges that Cunningham exceeded its permit limits for NOx and failed to report these exceedances as required by its permit. Prior to the formal administrative hearings, SPS negotiated a penalty of $0.8 million. The final agreement is currently being completed by both parties.

NSP-Minnesota NOV — In June 2011, NSP-Minnesota received an NOV from the EPA alleging violations of the NSR requirements of the CAA at the Sherburne County plant and Black Dog plant in Minnesota. The NOV specifically alleges that various maintenance, repair and replacement projects undertaken at the plants in the mid 2000s should have required a permit under the NSR process. NSP-Minnesota believes it has acted in full compliance with the CAA and NSR process. NSP-Minnesota also believes that the projects identified in the NOV fit within the routine maintenance, repair and replacement exemption contained within the NSR regulations or are otherwise not subject to the NSR requirements. NSP-Minnesota disagrees with the assertions contained in the NOV and intends to vigorously defend its position.

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 adverse effect on Xcel Energy’s financial position and results of operations.

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Environmental Litigation

State of Connecticut vs. Xcel Energy Inc. et al. — In 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court in the Southern District of New York against the following utilities, including Xcel Energy, to force reductions in carbon dioxide (CO2) emissions: American Electric Power Co., Southern Co., Cinergy Corp. (merged into Duke Energy Corporation) and Tennessee Valley Authority. The lawsuits allege that CO2 emitted by each company is a public nuisance. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its CO2 emissions. In September 2005, the court granted plaintiffs' motion to dismiss on constitutional grounds. In August 2010, this decision was reversed by the Second Circuit and was appealed to the U.S. Supreme Court. On June 20, 2011, the Supreme Court issued a ruling reversing the Second Circuit's decision, thereby dismissing plaintiffs' federal claims and remanding the case for further proceedings regarding the state law claims.

Native Village of Kivalina vs. Xcel Energy Inc. et al. — In 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. 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. No accrual has been recorded for this matter.

Comer vs. Xcel Energy Inc. et al. — On May 27, 2011, less than one 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. It is believed that this lawsuit is without merit. No accrual has been recorded for this matter.

Employment, Tort and Commercial Litigation

Qwest vs. Xcel Energy Inc. — In 2004, an employee of PSCo was seriously injured when a pole owned by Qwest malfunctioned. In September 2005, the employee commenced an action against Qwest in Colorado state court in Denver. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. In May 2007, the matter was tried and the jury found Qwest solely liable for the accident and this determination resulted in an award of damages in the amount of approximately $90 million. In April 2009, the Colorado Court of Appeals affirmed the jury verdict insofar as it relates to claims asserted by Qwest against PSCo. In February 2010, the Colorado Supreme Court agreed to review the Court of Appeals' decision as to the punitive damages issue but will not review the Court of Appeals' decision as it relates to PSCo. Oral arguments were presented in December 2010. In June 2011, the Colorado Supreme Court affirmed the decision of the Court of Appeals.

Cabin Creek Hydro Generating Station Accident — In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo's Cabin Creek Hydro Generating Station (CCH) near Georgetown, Colo. A fire occurred inside a pipe used to deliver water from a

reservoir to the hydro facility. Five RPI employees were unable to exit the pipe and rescue crews confirmed their deaths. The accident was investigated by the federal Occupational Safety and Health Administration (OSHA), the U.S. Chemical Safety Board (CSB) and the Colorado Bureau of Investigations.

In March 2008, OSHA proposed penalties totaling $189,900 for 22 serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. Pursuant to a court order this proceeding had been stayed until July 1, 2011. The stay has now been lifted, and the matter is expected to proceed.

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Three lawsuits were filed (two in Colorado state court and one in California state court) on behalf of the five deceased workers and by seven employees of RPI allegedly injured in the accident. PSCo and Xcel Energy Inc. were among the defendants named in each lawsuit. Settlements were subsequently reached in all three lawsuits by Xcel Energy Inc. and PSCo. These confidential settlements did not have a material adverse effect upon Xcel Energy's consolidated results of operations, cash flows or financial position.

In August 2009, the U.S. Government charged Xcel Energy Inc. and PSCo with five misdemeanor counts in federal court in Colorado for violation of an OSHA regulation related to the accident at Cabin Creek in October 2007. RPI Coatings, the contractor performing the work at the plant, and two individuals employed by RPI were also indicted. In September 2009, both Xcel Energy Inc. and PSCo entered a not-guilty plea. On June 28, 2011, a jury returned a not-guilty verdict on all accounts in favor of Xcel Energy Inc. and PSCo.

In August 2010, the CSB issued a report related to its investigation of the CCH accident. The report contains several findings and recommendations, some of which pertain to PSCo. Consistent with its delegated authority, the CSB investigation did not result in the issuance of any fines or penalties. PSCo has responded to the CSB concerning its recommendations.

Stone & Webster, Inc. vs. PSCo — In July 2009, Stone & Webster, Inc. (Shaw) filed a complaint against PSCo in State District Court in Denver, Colo. for damages allegedly arising out of its construction work on the Comanche Unit 3 coal-fired plant. Shaw, a contractor retained to perform certain engineering, procurement and construction work on Comanche Unit 3, alleges, among other things, that PSCo mismanaged the construction of Comanche Unit 3. Shaw further claims that this alleged mismanagement caused delays and damages. The complaint also alleges that Xcel Energy Inc. and related entities guaranteed Shaw $10 million in future profits under the terms of a 2003 settlement agreement. Shaw alleges that it will not receive the $10 million to which it is entitled. Accordingly, Shaw seeks an amount up to $10 million relating to the 2003 settlement agreement. In total, Shaw seeks approximately $144 million in damages.

PSCo denies these allegations and believes the claims are without merit. PSCo filed an answer and counterclaim in August 2009, denying the allegations in the complaint and alleging that Shaw has failed to discharge its contractual obligations and has caused delays, and that PSCo is entitled to liquidated damages and excess costs incurred. In total, PSCo is seeking approximately $82 million in damages. In June 2010, PSCo exercised its contractual right to draw on Shaw's letter of credit in the total amount of approximately $29.6 million. In September 2010, Shaw filed a second lawsuit related to PSCo's decision to draw on the letter of credit. PSCo denied the merits of this claim.

Trial commenced in October 2010 and addressed only those issues raised in the first complaint and did not include Shaw's claim asserted in the second lawsuit related to the letter of credit. In November 2010, a jury returned a verdict that awarded damages to Shaw and to PSCo. Specifically, the jury awarded a total of $84.5 million to Shaw but also awarded $70.0 million to PSCo for damages related to its counterclaims, for a net verdict to Shaw in the amount of $14.5 million. Shaw subsequently filed post trial motions, which the court denied. In March 2011, Shaw filed its notice of appeal on all issues raised at trial and in post-trial motions. PSCo filed a conditional cross-appeal on April 5, 2011. If the jury verdict remains unchanged it is not expected to have a material adverse effect on Xcel Energy's consolidated results of operations, cash flows or financial position.

Merricourt Wind Project Litigation — On April 1, 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. As a result, NSP-Minnesota recorded a $101 million deposit in the first quarter 2011, which was collected in April 2011. On May 5, 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. On that same day, 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 has filed a motion to dismiss. Arguments related to this motion are expected to be presented to the court on Sept. 16, 2011. No accrual has been recorded for this matter.

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Nuclear Power Operations and Waste Disposal

Nuclear Waste Disposal Litigation — In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the U.S. requesting breach of contract damages for the U.S. Department of Energy (DOE) failure to begin accepting spent nuclear fuel by Jan. 31, 1998, as required by the contract between the U.S. and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. In September 2007, the court awarded NSP-Minnesota $116.5 million in damages. In February 2008, the U.S. filed an appeal to the U.S. Court of Appeals for the Federal Circuit and NSP-Minnesota cross-appealed on the cost of capital issue.

In August 2007, NSP-Minnesota filed a second complaint against the U.S. in the U.S. Court of Federal Claims (NSP II), again claiming breach of contract damages for the DOE's continuing failure to abide by the terms of the contract. This lawsuit claimed damages for the period Jan. 1, 2005 through Dec. 31, 2008, which included costs associated with the storage of spent nuclear fuel at Prairie Island and Monticello, as well as the costs of complying with state regulation relating to the storage of spent nuclear fuel.

In July 2011, the U.S. and NSP-Minnesota executed a settlement agreement resolving both lawsuits, providing an initial $100 million payment from the U.S. to NSP-Minnesota, and providing a method by which NSP-Minnesota can recover its spent fuel storage costs through 2013, currently estimated to be an additional $100 million. The settlement does not address costs for used fuel storage after 2013; such costs could be the subject of future litigation. NSP-Minnesota will make the appropriate regulatory filings to address the best means of returning these settlement amounts to ratepayers and to deal with costs of litigation.

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 utilities. 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 investments and borrowings are eliminated upon consolidation.

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)	Three Months Ended June 30, 2011	Twelve Months Ended Dec. 31, 2010
Borrowing limit	$ 2,450	$ 2,177
Amount outstanding at period end	656	466
Average amount outstanding	548	263
Maximum amount outstanding	692	653
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at end of period	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.

During March of 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed new 4-year credit agreements. The total size of the credit facilities is $2.45 billion and each credit facility terminates in March 2015. Xcel Energy Inc. and its utility subsidiaries have the right to request an extension of the revolving termination date for two additional one year periods, subject to majority bank group approval.

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. Other features of the credit facilities include:

- Each of the credit facilities, other than NSP-Wisconsin's, may be increased by up to $200 million for Xcel Energy Inc., $100 million each for NSP-Minnesota and PSCo, and $50 million for SPS.

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- Each credit facility has a financial covenant requiring that the debt-to-total capitalization ratio of each entity be less than or equal to 65 percent. Each entity was in compliance at June 30, 2011 and Dec. 31, 2010 as evidenced by the table below:

	Debt-to-Total Capitalization Ratio	
	June 30, 2011	Dec. 31, 2010
NSP-Minnesota	48 %	49 %
PSCo	44	46
SPS	50	50
Xcel Energy	55	55
NSP-Wisconsin	49	N/A

If Xcel Energy Inc. or any of its utility subsidiaries do not comply with the covenant, an event of default may be declared, and if not remedied, any outstanding amounts due under the facility can be declared due by the lender.

- Each credit facility has a cross-default provision that provides Xcel Energy will be in default on its borrowings under the facility if it or any of its subsidiaries, comprising 15 percent or more of the consolidated assets, defaults on any indebtedness in an aggregate principal amount exceeding $75 million.
- The interest rates under these lines of credit are based on the Eurodollar rate, plus a borrowing margin based on the applicable credit ratings of 100 to 200 basis points per year.
- The commitment fees, also based on applicable long-term credit ratings, are calculated on the unused portion of the lines of credit at a range of 10 to 35 basis points per year.
  - NSP-Wisconsin’s intercompany borrowing arrangement with NSP-Minnesota was subsequently terminated.

At June 30, 2011, 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	$ 336.1	$ 463.9
PSCo	700.0	153.6	546.4
NSP-Minnesota	500.0	12.1	487.9
SPS	300.0	131.0	169.0
NSP-Wisconsin	150.0	35.0	115.0
Total	$ 2,450.0	$ 667.8	$ 1,782.2

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

All credit facility bank borrowings 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 facility outstanding at June 30, 2011 and Dec. 31, 2010.

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, 2011 and Dec. 31, 2010, there were $11.9 million and $10.1 million of letters of credit outstanding, respectively. An additional $1.1 million of letters of credit not issued under the credit facility were outstanding at June 30, 2011 and Dec. 31, 2010. The contract amounts of these letters of credit approximate their fair value and are subject to fees determined in the marketplace.

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 hierarchal 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.

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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 and international equity funds 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.

Investments in debt securities — Debt securities are primarily priced using recent trades and observable spreads from benchmark interest rates for similar securities, except for asset-backed and mortgage-backed securities, which also require significant, subjective risk-based adjustments to the interest rate used to discount expected future cash flows, which include estimated principal prepayments. Therefore, fair value measurements for asset-backed and mortgage-backed securities have been assigned a Level 3.

Commodity derivatives — The methods utilized to measure the fair value of commodity derivatives include the use of forward prices and volatilities to value commodity forwards and options. Levels are assigned to these fair value measurements based on the significance of the use of subjective forward price and volatility forecasts for commodities and delivery locations with limited observability, or the significance of contractual settlements that extend to periods beyond those readily observable on active exchanges or quoted by brokers. Electric commodity derivatives include financial transmission rights (FTRs), for which fair value is determined using complex predictive models and inputs including forward commodity prices as well as subjective forecasts of retail and wholesale demand, generation and resulting transmission system congestion. Given the limited observability of management’s forecasts for several of these inputs, fair value measurements for FTRs have been assigned a Level 3.

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, as well as an assessment of the impact of Xcel Energy’s own credit risk when determining the fair value of commodity derivative liabilities, the impact of considering credit risk was immaterial to the fair value of commodity derivative assets and liabilities 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 securities under the applicable accounting guidance. 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.

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Unrealized gains for the decommissioning fund were $100.6 million and $82.5 million at June 30, 2011 and Dec. 31, 2010, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $56.0 million and $65.2 million at June 30, 2011 and Dec. 31, 2010, respectively.

The following tables present the cost and fair value of Xcel Energy's non-derivative instruments recurring fair value measurements, the nuclear decommissioning fund investments, at June 30, 2011 and Dec. 31, 2010:

		June 30, 2011			
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$64,873	$62,384	$2,489	$-	$64,873
Commingled funds	220,000	-	223,922	-	223,922
International equity funds	54,563	-	63,736	-	63,736
Debt securities:					
Government securities	241,914	-	244,286	-	244,286
U.S. corporate bonds	189,055	-	197,611	-	197,611
Foreign securities	19,542	-	20,626	-	20,626
Municipal bonds	32,392	-	33,474	-	33,474
Asset-backed securities	20,198	-	-	21,004	21,004
Mortgage-backed securities	58,680	-	-	62,271	62,271
Equity securities:					
Common stock	442,416	456,426	-	-	456,426
Total	$1,343,633	$518,810	$786,144	$83,275	$1,388,229

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $96.7 million of equity investments in unconsolidated subsidiaries and $32.2 million of miscellaneous investments.

		Dec. 31, 2010			
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$83,837	$76,281	$7,556	$-	$83,837
Commingled funds	131,000	-	133,080	-	133,080
International equity funds	54,561	-	58,584	-	58,584
Debt securities:					
Government securities	146,473	-	146,654	-	146,654
U.S. corporate bonds	279,028	-	288,304	-	288,304
Foreign securities	1,233	-	1,581	-	1,581
Municipal bonds	100,277	-	97,557	-	97,557
Asset-backed securities	32,558	-	-	33,174	33,174
Mortgage-backed securities	68,072	-	-	72,589	72,589
Equity securities:					
Common stock	436,334	435,270	-	-	435,270
Total	$1,333,373	$511,551	$733,316	$105,763	$1,350,630

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $97.6 million of equity investments in unconsolidated subsidiaries and $28.2 million of miscellaneous

investments.

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The following tables present the changes in Level 3 nuclear decommissioning fund investments:

	Three Months Ended June 30,			
	2011		2010	
(Thousands of Dollars)	Mortgage-Backed Securities	Asset-Backed Securities	Mortgage-Backed Securities	Asset-Backed Securities
Balance at April 1	$ 98,367	$ 26,020	$ 109,044	$ 44,125
Purchases	52,952	-	-	2,538
Settlements	(88,584)	(5,206)	(45,329)	(6,757)
(Losses) gains recorded as regulatory assets and liabilities	(464)	190	1,344	161
Balance at June 30	$ 62,271	$ 21,004	$ 65,059	$ 40,067

	Six Months Ended June 30,			
	2011		2010	
(Thousands of Dollars)	Mortgage-Backed Securities	Asset-Backed Securities	Mortgage-Backed Securities	Asset-Backed Securities
Balance at Jan. 1	$ 72,589	$ 33,174	$ 81,189	$ 11,918
Purchases	99,065	756	46,477	36,042
Settlements	(108,457)	(13,116)	(66,175)	(8,109)
(Losses) gains recorded as regulatory assets and liabilities	(926)	190	3,568	216
Balance at June 30	$ 62,271	$ 21,004	$ 65,059	$ 40,067

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class at June 30, 2011:

	Final Contractual Maturity				
(Thousands of Dollars)	Due in 1 Year or Less	Due in 1 to 5 Years	Due in 5 to 10 Years	Due after 10 Years	Total
Government securities	$ 8,540	$ 140,767	$ 84,652	$ 10,327	$ 244,286
U.S. corporate bonds	349	50,672	127,922	18,668	197,611
Foreign securities	-	14,061	6,565	-	20,626
Municipal bonds	-	-	22,862	10,612	33,474
Asset-backed securities	-	9,889	11,115	-	21,004
Mortgage-backed securities	-	-	1,103	61,168	62,271
Debt securities	$ 8,889	$ 215,389	$ 254,219	$ 100,775	$ 579,272

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.

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, 2011, accumulated OCI related to interest rate derivatives included $0.7 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

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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 their 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, 2011, 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, 2011 and June 30, 2010.

At June 30, 2011, accumulated OCI related to commodity derivative cash flow hedges included $0.2 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 their electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating revenue, 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, 2011 and Dec. 31, 2010:

(Amounts in Thousands) (a)(b)	June 30, 2011	Dec. 31, 2010
Megawatt hours (MWh) of electricity	72,913	46,794
MMBtu of natural gas	56,462	75,806
Gallons of vehicle fuel	700	800

(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.

Financial Impact of Qualifying Cash Flow Hedges — The impact of qualifying interest rate and vehicle fuel cash flow hedges on Xcel Energy's accumulated OCI, included in the consolidated statements of common stockholders' equity and comprehensive income, is detailed in the following table:

	Three Months Ended June 30,	
(Thousands of Dollars)	2011	2010
Accumulated other comprehensive loss related to cash flow hedges at April 1	$(7,692)	$(5,783)
After-tax net unrealized losses related to derivatives accounted for as hedges	(38)	(4,413)
After-tax net realized losses on derivative transactions reclassified into earnings	148	606
Accumulated other comprehensive loss related to cash flow hedges at June 30	$(7,582)	$(9,590)

(Thousands of Dollars)	Six Months Ended June 30, 2011	2010
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(8,094)	$(6,435)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	206	(4,387)
After-tax net realized losses on derivative transactions reclassified into earnings	306	1,232
Accumulated other comprehensive loss related to cash flow hedges at June 30	$(7,582)	$(9,590)

Xcel Energy had no derivative instruments designated as fair value hedges during the three and six months ended June 30, 2011 and June 30, 2010. Therefore, no gains or losses from fair value hedges or related hedged transactions were recognized for these periods.

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The following tables detail the impact of derivative activity during the three and six months ended June 30, 2011 and June 30, 2010, on OCI, regulatory assets and liabilities, and income:

	Three Months Ended June 30, 2011				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period From:		
(Thousands of Dollars)	Other Comprehensive Loss	Regulatory Assets and Liabilities	Other Comprehensive Income (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 Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period From:		
(Thousands of Dollars)	Other Comprehensive Income	Regulatory Assets and Liabilities	Other Comprehensive Income (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

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	Three Months Ended June 30, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period From:		
(Thousands of Dollars)	Other Comprehensive Loss	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (7,210)	$ -	$ 260 (a)	$ -	$ -
Vehicle fuel and other commodity	(365)	-	783 (e)	-	-
Total	$ (7,575)	$ -	$ 1,043	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 224 (b)
Electric commodity	-	7,597	-	(2,111)(c)	-
Natural gas commodity	-	(4,612)	-	752 (d)	-
Other	-	-	-	-	85
Total	$ -	$ 2,985	$ -	$ (1,359)	$ 309

	Six Months Ended June 30, 2010				
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period From:		
(Thousands of Dollars)	Other Comprehensive Loss	Regulatory Assets and Liabilities	Other Comprehensive Income	Regulatory Assets and Liabilities	Pre-Tax Gains Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (7,210)	$ -	$ 419 (a)	$ -	$ -
Vehicle fuel and other commodity	(322)	-	1,693 (e)	-	-
Total	$ (7,532)	$ -	$ 2,112	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 5,605 (b)
Electric commodity	-	(9,582)	-	(4,838)	-
Natural gas commodity	-	(40,706)	-	4,707 (d)	-
Other	-	-	-	-	135 (b)

Total	$ -	$ (50,288)	$ -	$ (131)	$ 5,740

(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 O&M expenses.

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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 PSCo were downgraded below investment grade, contracts underlying $5.1 million and $5.6 million of derivative instruments in a gross liability position at June 30, 2011 and Dec. 31, 2010, respectively, would have required PSCo to post collateral or settle applicable contracts, which would have resulted in payments to counterparties of $5.7 million and $9.8 million, respectively. At June 30, 2011 and Dec. 31, 2010, 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, 2011 and Dec. 31, 2010.

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, 2011:

	June 30, 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	$-	$200	$-	$200	$ (91)	$109
Other derivative instruments:						
Trading commodity	410	27,456	42	27,908	(11,788)	16,120
Electric commodity	-	-	6,601	6,601	(2,618)	3,983
Natural gas commodity	19	250	-	269	(250)	19
Total current derivative assets	$429	$27,906	$6,643	$34,978	$ (14,747)	20,231
Purchased power agreements (a)						33,601
Current derivative instruments						$53,832
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$286	$-	$286	$ -	$286
Other derivative instruments:						
Trading commodity	-	35,416	-	35,416	(4,773)	30,643
Total noncurrent derivative assets	$-	$35,702	$-	$35,702	$ (4,773)	30,929
Purchased power agreements (a)						138,138
Noncurrent derivative instruments						$169,067

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	June 30, 2011					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Other derivative instruments:						
Trading commodity	$230	$22,110	$29	$22,369	$ (14,837)	$7,532
Electric commodity	-	-	2,618	2,618	(2,618)	-
Natural gas commodity	88	9,559	-	9,647	(341)	9,306
Total current derivative liabilities	$318	$31,669	$2,647	$34,634	$ (17,796)	16,838
Purchased power agreements (a)						23,152
Current derivative instruments						$39,990
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$17,275	$-	$17,275	$ (4,773)	$12,502
Total noncurrent derivative liabilities	$-	$17,275	$-	$17,275	$ (4,773)	12,502
Purchased power agreements (a)						259,979
Noncurrent derivative instruments						$272,481

(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.

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, 2011 and June 30, 2010.

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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, 2010:

	Dec. 31, 2010					
	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	$-	$126	$-	$126	$ -	$126
Other derivative instruments:						
Trading commodity	487	37,019	-	37,506	(21,352)	16,154
Electric commodity	-	-	3,619	3,619	(1,226)	2,393
Natural gas commodity	-	1,595	-	1,595	(1,219)	376
Total current derivative assets	$487	$38,740	$3,619	$42,846	$ (23,797)	19,049
Purchased power agreements (a)						35,030
Current derivative instruments						$54,079
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$150	$-	$150	$ -	$150
Other derivative instruments:						
Trading commodity	-	32,621	-	32,621	(4,595)	28,026
Natural gas commodity	-	1,246	-	1,246	(269)	977
Total noncurrent derivative assets	$-	$34,017	$-	$34,017	$ (4,864)	29,153
Purchased power agreements (a)						154,873
Noncurrent derivative instruments						$184,026

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	Dec. 31, 2010					
	Fair Value					
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Other derivative instruments:						
Trading commodity	$392	$30,608	$-	$31,000	$ (24,007)	$6,993
Electric commodity	-	-	1,227	1,227	(1,227)	-
Natural gas commodity	20	52,709	-	52,729	(21,169)	31,560
Total current derivative liabilities	$412	$83,317	$1,227	$84,956	$ (46,403)	38,553
Purchased power agreements (a)						23,192
Current derivative instruments						$61,745
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$18,878	$-	$18,878	$ (4,596)	$14,282
Natural gas commodity	-	438	-	438	(269)	169
Total noncurrent derivative liabilities	$-	$19,316	$-	$19,316	$ (4,865)	14,451
Purchased power agreements (a)						271,535
Noncurrent derivative instruments						$285,986

(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.

The following table presents the changes in Level 3 commodity derivatives for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30,	
(Thousands of Dollars)	2011	2010
Balance at April 1	$ 2,332	$ 3,946
Purchases	-	317
Settlements	27	(44)
Gains recognized in earnings (a)	4	1,294
Gains recorded as regulatory assets and liabilities	10,299	6,993
Gains reclassified from regulatory assets and liabilities to earnings	(8,666)	(2,700)
Balance at June 30	$ 3,996	$ 9,806

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(Thousands of Dollars)	Six Months Ended June 30, 2011	2010
Balance at Jan. 1	$ 2,392	$ 28,042
Purchases	-	(1,092)
Settlements	(59)	(67)
Gains (losses) recognized in earnings (a)	72	(1,739)
Gains (losses) recorded as regulatory assets and liabilities	19,145	(9,911)
Gains reclassified from regulatory assets and liabilities to earnings	(17,554)	(5,427)
Balance at June 30	$ 3,996	$ 9,806

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

Fair Value of Long-Term Debt

The historical cost and fair value of Xcel Energy's long-term debt are as follows:

	June 30, 2011		Dec. 31, 2010	
(Thousands of Dollars)	Historical Cost	Fair Value	Historical Cost	Fair Value
Long-term debt, including current portion	$9,317,483	$10,224,225	$9,318,559	$10,224,845

The fair value of Xcel Energy's long-term debt is estimated based on the quoted market prices for the same or similar issues, or the current rates for debt of the same remaining maturities and credit quality. The fair value estimates presented are based on information available to management as of June 30, 2011 and Dec. 31, 2010. These fair value estimates have not been comprehensively revalued for purposes of these consolidated financial statements since that date, and current estimates of fair values may differ significantly.

As of June 30, 2011 and Dec. 31, 2010, the historical cost of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities are representative of fair value because of the short-term nature of these instruments.

9. Other Income, Net

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of Dollars)	2011	2010	2011	2010
Interest income	$1,481	$1,243	$6,254	$3,294
Other nonoperating income	901	575	1,784	1,159
Insurance policy expense	(1,215)	(88)	(2,086)	(1,748)
Other nonoperating expense	(188)	(21)	(207)	(21)
Other income, net	$979	$1,709	$5,745	$2,684

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.

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Given the similarity of the regulated electric and regulated natural gas utility operations of its utility subsidiaries, 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 electricity which is transmitted and distributed 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 U.S. 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 $96.7 million and $97.6 million as of June 30, 2011 and Dec. 31, 2010, 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) Three Months Ended June 30, 2011	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
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) Three Months Ended June 30, 2010	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Operating revenues from external customers	$2,040,702	$249,410	$17,652	$-	$2,307,764
Intersegment revenues	259	2,857	-	(3,116)	-
Total revenue	$2,040,961	$252,267	$17,652	$(3,116)	$2,307,764
Income (loss) from continuing operations	$138,999	$10,243	$(13,617)	$-	$135,625

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

(Thousands of Dollars) Six Months Ended June 30, 2010	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Operating revenues from external customers	$4,036,294	$1,039,560	$39,372	$-	$5,115,226
Intersegment revenues	462	4,560	-	(5,022)	-
Total revenues	$4,036,756	$1,044,120	$39,372	$(5,022)	$5,115,226
Income (loss) from continuing operations	$254,181	$73,269	$(24,485)	$-	$302,965

11. Common Stock and Equivalents

Common Stock Equivalents — Xcel Energy Inc. has common stock equivalents consisting of 401(k) equity awards and stock options. Restricted stock units and performance shares are considered common stock equivalents when all necessary conditions for issuance have been satisfied by the end of the reporting period.

For the three months ended June 30, 2011 and 2010, Xcel Energy Inc. had approximately 2.4 million and 6.5 million stock options outstanding, respectively, that were antidilutive, and therefore, excluded from the earnings per share calculation. For the six months ended June 30, 2011 and 2010, Xcel Energy Inc. had approximately 2.5 million and 6.6 million stock options outstanding, respectively, that were antidilutive, and therefore, excluded from the earnings per share calculation. The dilutive impact of common stock equivalents affected earnings per share as follows for the three and six months ended June 30, 2011 and 2010:

	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$ 158,762			$ 139,776		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Earnings available to common shareholders	157,702	484,918	$ 0.33	138,716	460,041	$ 0.30
Effect of dilutive securities:						
401(k) equity awards	-	323		-	391	
Diluted earnings per share:						
Earnings available to common shareholders	$ 157,702	485,241	$ 0.33	$ 138,716	460,432	$ 0.30

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(Amounts in thousands, except per share data)	Six Months Ended June 30, 2011 Income	Shares	Per Share Amount	Six Months Ended June 30, 2010 Income	Shares	Per Share Amount
Net income	$ 362,331			$ 306,894		
Less: Dividend requirements on preferred stock	(2,120)			(2,120)		
Basic earnings per share:						
Earnings available to common shareholders	360,211	484,283	$ 0.74	304,774	459,483	$ 0.66
Effect of dilutive securities:						
401(k) equity awards	-	492		-	585	
Diluted earnings per share:						
Earnings available to common shareholders	$ 360,211	484,775	$ 0.74	$ 304,774	460,068	$ 0.66

12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended June 30,			
	2011	2010	2011	2010
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$20,548	$18,956	$1,097	$965
Interest cost	40,791	41,853	10,492	10,861
Expected return on plan assets	(55,514)	(58,035)	(8,013)	(7,131)
Amortization of transition obligation	-	-	3,611	3,611
Amortization of prior service cost (credit)	5,633	5,164	(1,233)	(1,233)
Amortization of net loss	20,527	13,134	3,304	3,113
Net periodic benefit cost	31,985	21,072	9,258	10,186
Costs not recognized and additional cost recognized due to the effects of regulation	(10,715)	(6,314)	973	973
Net benefit cost recognized for financial reporting	$21,270	$14,758	$10,231	$11,159

	Six Months Ended June 30,			
	2011	2010	2011	2010
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$38,660	$36,574	$2,412	$2,003
Interest cost	80,706	82,505	21,043	21,390
Expected return on plan assets	(110,800)	(116,159)	(15,981)	(14,265)
Amortization of transition obligation	-	-	7,222	7,222
Amortization of prior service cost (credit)	11,266	10,328	(2,466)	(2,466)
Amortization of net loss	39,256	24,158	6,647	5,822
Net periodic benefit cost	59,088	37,406	18,877	19,706
Costs not recognized and additional cost recognized due to the effects of regulation	(18,600)	(13,640)	1,946	1,946

Net benefit cost recognized for financial reporting	$40,488	$23,766	$20,823	$21,652

Voluntary contributions of $134 million were made to three of Xcel Energy's pension plans in January 2011. Based on updated valuation results received in March 2011 for the NCE Non-Bargaining Pension Plan, Xcel Energy made a required contribution of $3.3 million to the NCE Non-Bargaining Pension Plan in July 2011.

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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 unaudited consolidated financial statements and related notes to the consolidated financial statements. Due to the seasonality of Xcel Energy's electric and natural gas sales, such 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; 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 NSP-Minnesota's 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, 2010, and Item 1A and Exhibit 99.01 to this Quarterly Report on Form 10-Q for the quarter ended June 30, 2011.

Financial Review

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

The only common equity securities that are publicly traded are common shares of Xcel Energy Inc. The earnings and earnings per share (EPS) of each subsidiary discussed below do not represent a direct legal interest in the assets and liabilities allocated to such subsidiary but rather represent a direct interest in our assets and liabilities as a whole. EPS by subsidiary is a financial measure not recognized under GAAP that is calculated by dividing the net income or loss attributable to controlling interest of each subsidiary by the weighted average fully diluted Xcel Energy Inc. common shares outstanding for the period. We use this non-GAAP financial measure to evaluate earnings results and to

provide details of earnings results. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to our consolidated fully diluted EPS determined in accordance with GAAP as an indicator of operating performance.

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Results of Operations

The following table summarizes the diluted earnings per share for Xcel Energy:

	Three Months Ended June 30,		Six Months Ended June 30,	
Diluted Earnings (Loss) Per Share	2011	2010	2011	2010
PSCo	$ 0.15	$ 0.17	$ 0.35	$ 0.40
NSP-Minnesota	0.13	0.09	0.32	0.24
SPS	0.05	0.05	0.07	0.07
NSP-Wisconsin	0.02	0.01	0.05	0.04
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.02	0.02
Regulated utility — continuing operations	0.36	0.33	0.81	0.77
Xcel Energy Inc. and other costs	(0.03)	(0.04)	(0.07)	(0.06)
Ongoing diluted earnings per share	0.33	0.29	0.74	0.71
COLI settlement and Medicare Part D	-	-	-	(0.06)
Earnings per share from continuing operations	0.33	0.29	0.74	0.65
Earnings per share from discontinued operations	-	0.01	-	0.01
GAAP diluted earnings per share	$ 0.33	$ 0.30	$ 0.74	$ 0.66

Ongoing earnings exclude adjustments for certain items. For 2010, these adjustments are related to the corporate owned life insurance (COLI) program and to the Patient Protection and Affordable Care Act — Medicare Part D.

Adjustments to GAAP Earnings

P.S.R. Investments, Inc. (PSRI) — During the first quarter of 2010, Xcel Energy recorded a non-recurring tax and interest charge of approximately $10 million, or $0.02 per share, due to an agreement in principle reached with the IRS following the completion of a financial reconciliation of Xcel Energy's statement of account dating back to tax year 1993, related to the COLI program.

Impact of the Patient Protection and Affordable Care Act — Medicare Part D — During the first quarter of 2010, Xcel Energy recorded non-recurring tax expense of approximately $17 million, or $0.04 per share, of tax benefits previously recognized in income related to Medicare Part D subsidies due to the Patient Protection and Affordable Care Act enacted in March 2010. Under GAAP, Xcel Energy was required to reverse these previously recorded tax benefits in the period of enactment of the new legislation.

Xcel Energy's management believes that ongoing earnings provide a meaningful comparison of earnings results and is representative of Xcel Energy's fundamental core earnings power. Xcel Energy's management uses ongoing earnings internally for financial planning and analysis, for reporting of results to the Board of Directors, in determining whether performance targets are met for performance-based compensation and when communicating its earnings outlook to analysts and investors.

Earnings Adjusted for Certain Items (Ongoing Earnings)

Xcel Energy — Overall, ongoing earnings increased by $0.04 per share for the second quarter and by $0.03 per share for the six months ended June 30, 2011.

PSCo — PSCo earnings decreased by $0.02 per share for the second quarter and by $0.05 per share for the six months ended June 30, 2011. The decreases are mainly due to seasonal rates, which were implemented in June 2010 and

higher O&M expenses, property taxes and depreciation expense. Seasonal rates are designed to be revenue neutral on an annual basis. Therefore, the quarterly pattern of revenue collection is different than in the past, as seasonal rates are higher in the summer months and lower throughout the other months of the year.

NSP-Minnesota — NSP-Minnesota earnings increased by $0.04 per share for the second quarter and by $0.08 per share for the six months ended June 30, 2011. The increases are primarily due to interim rate increases, subject to refund, in Minnesota and North Dakota effective in the first quarter of 2011, partially offset by higher O&M expenses, property taxes and depreciation expense.

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SPS — SPS earnings per share were flat for the second quarter and for the six months ended June 30, 2011 when compared to the respective periods of 2010. Higher electric revenues, primarily due to Texas retail rate increases in February 2011 as well as warmer weather in May and June 2011 were offset by higher O&M expenses, property taxes, depreciation expense and the reversal of fuel cost allocation reserves in 2010.

NSP-Wisconsin — NSP-Wisconsin earnings increased by $0.01 per share for both the second quarter and for the six months ended June 30, 2011. The increase is due to implementation of new electric rates, which were effective in January 2011, and were partially offset by higher O&M and depreciation expenses.

Changes in Diluted Earnings Per Share

The following tables summarize significant components contributing to the changes in the diluted earnings per share compared with prior periods, which are discussed in more detail below.

Diluted Earnings (Loss) Per Share	Three Months Ended June 30,	Six Months Ended June 30,
2010 GAAP diluted earnings per share	$0.30	$0.66
Earnings per share from discontinued operations	(0.01)	(0.01)
2010 diluted earnings per share from continuing operations	0.29	0.65
COLI settlement, PSRI and Medicare Part D	-	0.06
2010 ongoing diluted earnings per share	0.29	0.71
Components of change — 2011 vs. 2010		
Higher electric margins	0.11	0.23
Higher natural gas margins	0.01	0.03
Higher operating and maintenance expenses	(0.02)	(0.06)
Higher depreciation and amortization	(0.02)	(0.05)
Higher taxes (other than income taxes)	(0.02)	(0.04)
Dilution from DSPP, benefit plans and the 2010 common equity issuance	(0.02)	(0.04)
Higher conservation and DSM expenses (generally offset in revenues)	(0.01)	(0.04)
Other, net	0.01	-
2011 GAAP and ongoing diluted earnings per share	$0.33	$0.74

The following table provides a reconciliation of ongoing and GAAP earnings and earnings per diluted share:

Contributions to Income (Millions of Dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
GAAP income (loss) by segment				
Regulated electric income	$162.5	$139.0	$317.1	$254.2
Regulated natural gas income	6.6	10.2	65.2	73.3
Other income (loss)(a)	4.8	3.9	9.6	(0.4)
Segment income — continuing operations	173.9	153.1	391.9	327.1
Xcel Energy Inc. and other costs (a)	(15.2)	(17.5)	(29.8)	(24.1)
Total income — continuing operations	158.7	135.6	362.1	303.0
Income from discontinued operations	0.1	4.2	0.2	3.9
Total GAAP net income	$158.8	$139.8	$362.3	$306.9

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Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended June 30, 2011	2010	Six Months Ended June 30, 2011	2010
GAAP earnings (loss) by segment				
Regulated electric	$0.34	$0.30	$0.65	$0.55
Regulated natural gas	0.01	0.02	0.14	0.16
Other (a)	0.01	0.01	0.02	-
Segment earnings per share — continuing operations	0.36	0.33	0.81	0.71
Xcel Energy Inc. and other costs(a)	(0.03)	(0.04)	(0.07)	(0.06)
Total earnings per share — continuing operations	0.33	0.29	0.74	0.65
Discontinued operations	-	0.01	-	0.01
Total GAAP earnings per share — diluted	$0.33	$0.30	$0.74	$0.66

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

Statement of Income Analysis

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

Estimated Impact of Temperature Changes on Regulated Earnings — Unseasonably 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 as follows:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010
HDD	0.9%	(16.3)%	20.5%	4.4%	(2.4)%	7.0%
CDD	33.9	17.5	14.0	33.5	17.8	13.3
THI	(6.4)	6.4	(12.1)	(6.4)	6.4	(12.1)

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2011 vs. Normal	2010 vs. Normal	2011 vs. Normal	2011 vs. Normal	2010 vs. Normal	2011 vs. Normal
Retail electric	$0.00	$0.01	$(0.01)	$0.01	$0.01	$0.00
Firm natural gas	0.00	(0.01)	0.01	0.00	(0.01)	0.01
Total	$0.00	$0.00	$0.00	$0.01	$0.00	$0.01

Sales Growth (Decline) — The following table summarizes Xcel Energy's regulated sales growth (decline) for actual and weather-normalized sales in 2011:

	Three Months Ended June 30,			
	Actual	Weather Normalized	Actual Lubbock (a)	Weather Normalized Lubbock (a)
Electric residential	(0.8) %	(0.2) %	0.2 %	0.7 %
Electric commercial and industrial	(0.1)	0.0	0.8	0.9
Total retail electric sales	(0.2)	0.0	0.7	0.9
Firm natural gas sales	2.7	(4.9)	N/A	N/A

	Six Months Ended June 30,			
	Actual	Weather Normalized	Actual Lubbock (a)	Weather Normalized Lubbock (a)
Electric residential	(0.3) %	(0.5) %	0.6 %	0.4
Electric commercial and industrial	0.3	0.3	1.2	1.2
Total retail electric sales	0.2	0.1	1.1	1.0
Firm natural gas sales	1.5	(2.8)	N/A	N/A

(a) Adjusted for the October 2010 sale of SPS electric distribution assets to the city of Lubbock, Texas.

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 tables details the electric revenues and margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of Dollars)	2011	2010	2011	2010
Electric revenues	$2,128	$2,041	$4,158	$4,036
Electric fuel and purchased power	(989)	(986)	(1,921)	(1,975)
Electric margin	$1,139	$1,055	$2,237	$2,061

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

Electric Revenues

(Millions of Dollars)	Three Months Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
Revenue requirements for PSCo gas generation acquisition (a)	$35	$69
Retail rate increases, including seasonal rates (Minnesota interim, Wisconsin, Texas, North Dakota interim and Colorado)	23	58
Transmission revenue	13	25
Trading, including PSCo renewable energy credit sales	10	3
Conservation and DSM revenue, (partially offset by expenses)	10	18
Conservation and DSM incentive	9	8
Non-fuel riders	3	11
Firm wholesale	1	2
SPS fuel cost allocation regulatory accruals (b)	(11)	(11)
Fuel and purchased power cost recovery	(2)	(58)
Other, net	(4)	(3)
Total increase in electric revenues	$87	$122

Electric Margin

(Millions of Dollars)	Three Months Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
Revenue requirements for PSCo gas generation acquisition (a)	$35	$69
Retail rate increases, including seasonal rates (Minnesota interim, Wisconsin, Texas, North Dakota interim and Colorado)	23	58
Conservation and DSM revenue, (partially offset by expenses)	10	18
Conservation and DSM incentive	9	8
Transmission revenue, net of costs	7	10
Non-fuel riders	3	11
Firm wholesale	2	4
Trading, including PSCo renewable energy credit sales	2	(2)
SPS fuel cost allocation regulatory accruals (b)	(11)	(11)
Other, net	4	11
Total increase in electric margin	$84	$176

(a) The increase in revenue requirements for PSCo generation reflects the acquisition of the Rocky Mountain and Blue Spruce natural gas facilities in late 2010. These revenue requirements are partially offset by increased O&M expense, depreciation expense, property taxes and financing costs.

(b)

During the second quarter of 2010, SPS resolved certain fuel cost allocation issues allowing for the release of previously established reserves of approximately $11 million.

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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 tables details natural gas revenues and margin:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Millions of Dollars)	2011	2010	2011	2010
Natural gas revenues	$292	$249	$1,057	$1,040
Cost of natural gas sold and transported	(163)	(127)	(706)	(708)
Natural gas margin	$129	$122	$351	$332

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
Purchased natural gas adjustment clause recovery	$36	$(1)
Estimated impact of weather	4	9
Conservation and DSM revenue, (partially offset by expenses)	1	11
Conservation and DSM incentive	1	1
Retail sales decrease (excluding weather impact)	(1)	(3)
Other, net	2	-
Total increase in natural gas revenues	$43	$17

Natural Gas Margin

(Millions of Dollars)	Three Months Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
Estimated impact of weather	$4	$9
Conservation and DSM revenue, (partially offset by expenses)	1	11
Conservation and DSM incentive	1	1
Retail sales decrease (excluding weather impact)	(1)	(3)
Other, net	2	1
Total increase in natural gas margin	$7	$19

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased by approximately $15.5 million, or 3.0 percent, for the second quarter and by $44.6 million, or 4.5 percent for the six months ended June 30, 2011 compared with 2010. The following table summarizes the changes in other O&M expenses:

(Millions of Dollars)	Three Months Ended June 30, 2011 vs. 2010	Six Months Ended June 30, 2011 vs. 2010
Higher plant generation costs	$13	$18
Higher labor and contract labor costs	5	13
Higher bad debt expense	2	1
Higher employee benefit expense	-	5
Other, net	(4)	8
Total increase in operating and maintenance expenses	$16	$45

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- Higher plant generation costs are attributable to incremental costs associated with new generation placed in service in 2010 and a higher level of scheduled maintenance and overhaul work.
- Higher labor and contract labor costs are primarily due to maintenance on our distribution facilities, particularly in Colorado and the impact of annual wage increases.
- Higher employee benefit costs for the six month comparable periods are primarily due to higher pension expense.

Conservation and Demand Side Management (DSM) Program Expenses — Conservation and DSM program expenses increased by approximately $9.9 million, or 17.9 percent for the second quarter and by $27.2 million, or 24.0 percent for the six months ended June 30, 2011, compared with the same periods in 2010. The higher expense is attributable to timing and an increase in the rider rates used to recover the program expenses. Conservation and DSM program expenses are generally recovered in our major jurisdictions concurrently through riders and base rates. Overall, the programs are designed to encourage the operating companies and their retail customers to conserve energy or change energy usage patterns in order to reduce peak demand on the gas or electric system. This, in turn, reduces the need for additional plant capacity, reduces emissions, serves to achieve other environmental goals as well as reduces energy costs to participating customers.

Depreciation and Amortization — Depreciation and amortization increased by approximately $17.8 million, or 8.4 percent for the second quarter and by $36.4 million, or 8.7 percent for the six months ended June 30, 2011, compared with the same periods in 2010. The increase in depreciation expense is primarily due to Comanche Unit 3 going into service in mid-May 2010, the Nobles Wind Project commencing commercial operations in late 2010, the acquisition of two gas generation facilities in December 2010 and normal system expansion.

Taxes (Other Than Income Taxes) — Taxes (other than income taxes) increased by approximately $11.5 million, or 14.2 percent for the second quarter and by $26.7 million, or 16.4 percent for the six months ended June 30, 2011, compared with the same periods in 2010. The increase is primarily due to an increase in property taxes in Colorado and Minnesota.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC increased by approximately $1.9 million, or 9.6 percent for the second quarter and by $1.5 million, or 3.8 percent for the six months ended June 30, 2011, compared with the same periods in 2010. The increase is primarily due to construction projects related to NSP-Minnesota‘s Monticello extended power uprate and the new SPS Jones Unit 3, which went in service in late June 2011.

Interest Charges — Interest charges increased by approximately $4.9 million, or 3.5 percent for the second quarter and by $5.4 million, or 1.9 percent for the six months ended June 30, 2011, compared with the same periods in 2010. The increase is due to higher long-term debt levels to fund investments in utility operations, partially offset by lower interest rates.

Income Taxes — Income tax expense for continuing operations increased $7.7 million for the second quarter of 2011, compared with the same period in 2010. The increase in income tax expense was primarily due to an increase in pretax income in 2011 partially offset by increased wind production tax credits in 2011. The effective tax rate for continuing operations was 34.8 percent for the second quarter of 2011 compared with 36.2 percent for the same period in 2010. The lower effective tax rate for 2011 was primarily due to a lower forecasted annual effective tax rate for 2011 as compared to 2010, which was primarily due to increased wind production tax credits in 2011.

Income tax expense for continuing operations decreased $2.2 million for the first six months of 2011, compared with the first six months of 2010. The decrease in income tax expense was primarily due to the 2010 adjustments for a write-off of tax benefit previously recorded for Medicare Part D subsidies, an adjustment related to the COLI Tax Court proceedings, and an increase in 2011 wind production tax credits. These were partially offset by a reversal of a

valuation allowance for certain state tax credit carryovers in 2010 and an increase in pretax income in 2011. The effective tax rate for continuing operations was 35.2 percent for the six months ended June 30, 2011 compared with 39.6 percent for the same period in 2010. The higher effective tax rate for 2010 was primarily due to the Medicare Part D, COLI, and valuation allowance adjustments referenced above. Without these adjustments, the effective tax rate for continuing operations for the first six months of 2010 would have been 35.8 percent.

Factors Affecting Results of Operations

Fuel Supply and Costs

See the discussion of fuel supply and costs in Item 7 in Xcel Energy Inc.'s Annual Report on Form 10-K filed for the year ended Dec. 31, 2010.

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Utility Competition — The FERC has continued to promote competitive wholesale markets through open access transmission and other means. As a consequence, Xcel Energy Inc.'s utility subsidiaries and their wholesale customers can purchase the output from generation resources of competing wholesale suppliers and use the transmission systems of the utility subsidiaries on a comparable basis to the utility subsidiaries' to serve their native load. NSP-Wisconsin's two largest wholesale customers, the cities of Medford, Wis. and Rice Lake, Wis., issued notices in December 2010 that Medford will terminate service at the end of 2011 and Rice Lake will terminate service at the end of 2012. Subsequently, the remaining eight municipal wholesale customers issued notices stating power supply contracts with NSP-Wisconsin will be cancelled at the end of 2012 and power will be purchased from an alternate supplier starting in 2013. Until the contracts terminate, the municipal wholesale customers will be served under their existing contracts and the formula rate. In 2010, these ten municipal wholesale customers represented approximately 6 percent of NSP-Wisconsin's total electric operating revenue.

Public Utility Regulation

NSP-Minnesota

Wind Generation — NSP-Minnesota invested approximately $500 million in wind generation through 2010. The 201 MW Nobles wind project in southwestern Minnesota began commercial operations in 2010. The portion of the costs for the Nobles wind project assigned to Minnesota electric retail customers is currently being collected through the renewable energy standard rider. NSP-Minnesota had included the costs for the Nobles wind project in its current pending rate case in Minnesota and if approved, the costs will be recovered in base rates when final rates are implemented.

On April 1, 2011, NSP-Minnesota terminated its agreement with enXco for the development of the 150 MW Merricourt wind project in North Dakota. NSP-Minnesota's decision to terminate the agreement 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 agreement due to the nonperformance by enXco 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. The Merricourt wind project was projected to cost approximately $400 million and was expected to reach commercial operation in 2011.

On May 5, 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 agreement. On that same day, 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 in response a motion to dismiss. Arguments related to this motion are expected to be presented to the court on Sept. 16, 2011.

NSP-Minnesota Transmission Certificate of Need (CONs) — In May 2009, the MPUC granted a CON to construct three 345 kilovolt (KV) electric transmission lines as part of the CapX2020 project. The project to build the three lines includes construction of approximately 700 miles of new facilities at a cost of approximately $1.9 billion. NSP-Minnesota and NSP-Wisconsin are responsible for approximately $1.0 billion of the total cost. The remainder of the costs will be born by other utilities in the upper Midwest. These cost estimates will be revised after the regulatory process is completed.

NSP-Minnesota and Great River Energy filed four route permit applications with the MPUC in addition to a facility permit application with the SDPUC, a certificate of corridor compatibility application with the NDPSC and a Certificate of Public Convenience and Necessity (CPCN) application with the PSCW. The MPUC has issued route permits for the Monticello, Minn. to St. Cloud, Minn. project, the Minnesota portion of the Fargo, ND to St. Cloud, Minn. project and the Minnesota portion of the Brookings, SD to Hampton, Minn. project. The SDPUC granted the

facility permit for the South Dakota portion of the Brookings, SD project in June 2011. The remaining required permit activities are on-going in North Dakota for the Fargo project and in Wisconsin and Minnesota for the Hampton, Minn. to La Crosse, Wis. project.

Also in June 2011, the Midwest Independent Transmission System Operator, Inc. (MISO) granted approval of the Brookings line as a multi value line, subject to regional cost allocation contingent on approving the portfolio of projects with which it was evaluated. The projects studied create a net benefit to the region in aggregate and the MISO expects to take up approvals of the remainder of the portfolio by the end of 2011.

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Bemidji to Grand Rapids Project
In July 2009, the MPUC approved the CON application for a 230 KV CapX2020 transmission line between Bemidji, Minn. and Grand Rapids, Minn. Route permit hearings were concluded in May 2010, and a route permit was approved by the MPUC in November 2010. In February 2011, the Leech Lake Band of Ojibwa filed a letter with the MPUC requesting suspension or revocation of the route permit. The MPUC has denied granting that request pending court action on the issue. This line is expected to entail construction of approximately 68 miles of new facilities at a cost of $100 million. Construction related activities began in January 2011 and are expected to be completed in 2012. The estimated project cost to NSP-Minnesota is approximately $26 million.

Hiawatha Transmission Project
In November 2010, NSP-Minnesota submitted a CON application to the MPUC for two 115 KV lines in Minneapolis, Minn. Hearings on the CON are expected to be held in late 2011 with an expectation of an MPUC decision of the CON and route permit by the end of 2011.

Glencoe to Waconia Project
In November 2010, NSP-Minnesota submitted a CON to the MPUC for 115 KV transmission line upgrades to the Glencoe, Minn. to Waconia, Minn. 69 KV line. This was followed by a route permit application filed in December 2010. Hearings on both applications are expected to be held in the third quarter of 2011 with an expectation of an MPUC decision regarding both applications by the end of 2011.

Bluff Creek to Westgate Project
In April 2011, NSP-Minnesota filed a notice plan in anticipation of filing a request for a CON for the upgrade of a 69 KV line to 115 KV in or near the cities of Chanhassen, Shorewood, Excelsior, Deephaven, Greenwood, Minnetonka, and Eden Prairie, Minn.

Black Dog Repowering CON — In March 2011, NSP-Minnesota filed a request with Minnesota regulators to approve a CON for a project to retire its last two coal-burning units (Units 3 and 4) at the Black Dog plant in Burnsville, Minn. and replace them with combined-cycle natural gas burning units. Units 1 and 2 were converted to natural gas combined-cycle operation in 2002.

The proposed Black Dog repowering project would replace the remaining 253 MW of coal-fired generating capacity at the site with about 700 MW of natural gas-fired generation. The Black Dog proposal requires review and approval by various state agencies, including the MPCA and MPUC.

If the Black Dog project is approved, site preparation could begin in 2012 and foundation construction in 2013. The new natural gas powered facility is expected to cost approximately $600 million and is proposed to come on line in 2016. The proposed in-service date is subject to potential change depending on projected load requirements.

Under the MPUC process, competitive alternatives to the Black Dog project were to be filed by July 1, 2011. On June 30, 2011, Calpine Corporation filed a competitive proposal to build out its Mankato Energy Center thereby adding 345 MW of capacity.

Nuclear Power Operations and Waste Disposal

NSP-Minnesota owns two nuclear generating plants: the Monticello plant, which has one unit, and the Prairie Island plant, which has two units. See Note 15 to the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 2010 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.

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NRC Regulation — The NRC regulates the nuclear operations of NSP-Minnesota. Decisions by the NRC can significantly impact the operations of the nuclear plants. The event at the nuclear plant in Fukushima, Japan could impact the NRC's deliberations on NSP-Minnesota's power uprates discussed below. This event could also result in additional regulation by the NRC, which could require additional capital expenditures or operating expenses. The NRC has created an internal task force that will develop recommendations for NRC consideration 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. On July 12, 2011, the task force released its recommendations in a written report. The report confirms the safety of U.S. nuclear energy facilities and recommends actions to enhance U.S. nuclear plant readiness to safely manage severe events. If the Commissioners adopt the recommendations in the report, a schedule for implementation and compliance will be established that licensees must adhere to. To better coordinate response activities, the U.S. nuclear energy industry has created a steering committee made up of representatives from major electric sector organizations to integrate and coordinate the industry's ongoing responses. In addition, the NRC has completed inspecting licensees' preparedness to deal with power losses or damage to large areas of a reactor site following extreme events.

Nuclear Plant Power Uprates and Life Extension

Monticello Nuclear Extended Power Uprate — In 2008, NSP-Minnesota filed for an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello plant. The MPUC approved the extended power uprate in 2008. The filing was placed on hold by the NRC staff to address concerns raised by the Advisory Committee for Reactor Safety related to containment pressure associated with pump performance. The containment pressure issue was addressed by the NRC staff in early 2011 and the NRC Commissioners provided direction to the NRC staff in a Staff Requirements memorandum in March 2011. NSP-Minnesota was subsequently verbally informed that the NRC staff was resuming their reviews of all active extended power uprate license amendment applications that had been placed on hold pending resolution of the containment pressure issue. NSP-Minnesota is currently working with the NRC staff to determine what needs to be done to complete the extended power uprate license amendment application and continue to work toward completing the extended power uprate modifications during the mid-cycle outage scheduled to begin in the fourth quarter of 2011. This schedule is expected to allow NSP-Minnesota to operate Monticello at the higher power level once final NRC approval is obtained.

Prairie Island Life Extension — In June 2011, the NRC issued renewed operating licenses for Prairie Island Units 1 and 2, allowing Unit 1 to operate until 2033 and Unit 2 until 2034.

Prairie Island Nuclear Extended Power Uprate — In 2008, NSP-Minnesota filed for an extended power uprate of approximately 164 MW for Prairie Island Units 1 and 2, which the MPUC approved in 2009. NSP-Minnesota is working toward filing an application to the NRC requesting an extended power uprate for both units at Prairie Island in late 2011. It is anticipated that the NRC's review of this application would take approximately two years with approval expected before the end of 2013. The extended power uprates are scheduled to be implemented during the 2014 and 2015 refueling outages.

NSP-Wisconsin

NSP-Wisconsin CPCN — An application for a CPCN for the Wisconsin portion of the CapX2020 project was filed with the PSCW in January 2011. In June 2011, the PSCW determined the application was complete, which triggers the 360-day deadline for the PSCW to grant a CPCN for the project. There have been issues raised by the Wisconsin Department of Transportation regarding placement of one of the routes near the Great River Road and by the WDNR regarding a section of a route which passes through the Van Loon Wildlife Area in Wisconsin. There are route options which could avoid those areas if the PSCW determines those issues warrant such a decision. No major issues regarding need have been raised and it is expected a decision will be issued in mid-2012.

Fuel and Purchased Energy Cost Recovery Mechanisms — NSP-Wisconsin does not have an automatic electric fuel adjustment clause for Wisconsin retail customers. Instead, under Wisconsin administrative rules, utilities must submit a forward-looking annual fuel cost plan to the PSCW for approval. Once the PSCW approves the fuel cost plan, utilities must defer the amount of any fuel cost over-collection or under-collection in excess of a two percent annual tolerance band, for future rate recovery or refund. Approval of a fuel cost plan and any rate adjustment for refund or recovery of deferred costs is determined by the PSCW after opportunity for a hearing. Rate recovery of deferred fuel cost is subject to an earnings test based on the utility's most recently authorized ROE. These rules first went into effect in January 2011.

NSP-Wisconsin's wholesale electric rate schedules include a fuel clause adjustment to provide for adjustments to billings and revenues for changes in the cost of fuel and purchased energy.

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NSP-Wisconsin's retail electric rate schedules for Michigan customers include power supply cost recovery factors, which are based on 12-month projections. After each 12-month period, reconciliation is submitted whereby over-collections are refunded and any under-collections are collected from the customers over the subsequent 12-month period.

Wisconsin Energy Efficiency and Conservation Goals — In 2010, the Wisconsin legislature approved a recommendation by the PSCW to increase state energy efficiency and conservation funding. In June 2011, the Wisconsin 2011-2012 biennial budget bill was signed into law. Among other things, the budget rolled back the projected increases for state energy efficiency and conservation funding to the levels in place prior to the legislature's actions in 2010, effective beginning in 2012. Based on this action, NSP-Wisconsin expects to be allocated approximately $8.2 million of the statewide program costs in 2012, increasing to approximately $9.1 million by 2014. Historically, NSP-Wisconsin has recovered these costs in rate charges to Wisconsin retail customers and expects to recover the program costs in rates going forward.

PSCo

Solar*Rewards Program — In February 2011, PSCo filed to reduce the payments to customers installing on-site solar generation due to changes in market conditions resulting from the decrease in cost of solar energy. In March 2011, PSCo entered into a settlement agreement with CPUC Staff, OCC, Colorado Solar Energy Industries Association, Solar Alliance, Western Resource Advocates, Colorado Governor's Energy Office and Colorado Renewable Energy Society that limits the amount of customer sited solar generation that PSCo will purchase, caps the amount PSCo will spend on customer sited solar, and quickly shifts from up-front payments to pay-for-performance. The settlement gives PSCo a presumption of prudence, for both the existing RESA balance, and the future RESA balance if PSCo performs consistent with the acquisition terms of the settlement. The CPUC approved the settlement and the program was reopened on March 23, 2011. Separately, the CPUC approved a change to the treatment of REC trading margins that allows the customers' share of the margins through the end of the pilot period, approximately $54 million, to be netted against the RESA regulatory asset balance. At June 30, 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

CACJA — The CACJA was signed into law in April 2010. The CACJA required PSCo to file a comprehensive plan to reduce annual emissions of NOx by at least 70 to 80 percent or greater from 2008 levels by 2017 from the coal-fired generation identified in the plan. The plan was required to consider both current and reasonably foreseeable CAA requirements and allows PSCo to propose emission controls, plant refueling, or plant retirement of at least 900 MW of coal-fired generating units in Colorado by Dec. 31, 2017. The legislation further encourages PSCo to submit long-term gas contracts to the CPUC for approval. The CACJA permits the CPUC to consider interim rate increases after Jan. 1, 2012, while the rate filing is pending and allows for multi-year rate plans.

In December 2010, the CPUC approved the following:

- Shutdown Cherokee Units 1 and 2 in 2011 and Cherokee Unit 3 (365 MW in total) by the end of 2015, 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 fuel-switch Unit 4 (111 MW) in 2014 to natural gas;
- Shutdown Valmont Unit 5 (186 MW) in 2017;
- Install SCR for controlling NOx and a scrubber for controlling SO2 on Pawnee Station in 2014;
- Install SCR on Hayden Unit 1 in 2015 and Hayden Unit 2 in 2016; and
- Convert Cherokee Unit 2 and Arapahoe Unit 3 to synchronous condensers to support the transmission system.

The CPUC provided for recovery on construction work in process (CWIP) in rate base in each rate case and deferred accounting of accelerated depreciation costs. PSCo needs to make applications for detailed cost review before commencing each phase of the plan. The CPUC also encouraged PSCo to hold stakeholder meetings to discuss issues around a multi-year rate plan. In January 2011, the Colorado Air Quality Control Commission unanimously approved incorporation of the CACJA plan into Colorado's regional haze SIP. See Note 3 and Note 5 to the consolidated financial statements for discussion. In April 2011, the Colorado General Assembly approved legislation authorizing the regional haze SIP containing the CACJA plan. Upon signature by the Governor of Colorado, the SIP (including the CACJA plan) was sent to the EPA for incorporation into federal CAA regulations. The total investment associated with the adopted plan is approximately $1.0 billion over the next seven years. The rate impact of the proposed plan is expected to increase future bills on average by 2 percent annually.

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In March 2011, PSCo filed an application for approval of the conversion of Cherokee Unit 2 to a synchronous condenser and notified the CPUC that it could maintain transmission system reliability potentially without conversion of Arapahoe Unit 3. PSCo and parties submitted an unopposed motion to approve the CPCN for Cherokee Unit 2 and defer the decision on Arapahoe Unit 3 until after a full reliability study is completed by the end of 2012. The Administrative Law Judge (ALJ) is expected to issue a decision regarding the settlement by the end of the third quarter 2011.

In April 2011, PSCo filed for approval of the decommissioning of Cherokee 1 and 2 to provide space for the new combined-cycle plant. Although answer testimony was due July 8, 2011, none was filed. In addition, PSCo filed for approval of the emissions controls on Pawnee Station. Hearing dates for this matter have been scheduled for Oct. 17-19, 2011.

Cameo Generating Station — In 2008, the CPUC approved PSCo's request to retire the 73 MW Cameo coal-fired generating station at the end of 2011. Cameo Station was retired at the end of 2010. In February 2011, PSCo filed a plan for decommissioning, remediation, removal, and restoration at the site. The plan was approved without hearing and work is expected to begin during the summer of 2011.

San Luis Valley-Calumet-Comanche Unit 3 Transmission Project — In May 2009, PSCo and Tri-State Generation and Transmission Association filed a joint application with the CPUC for a project for 230 KV and 345 KV line and substation construction. The line is intended to assist in bringing solar power in the San Luis Valley to customers. The line was originally expected to be placed in-service in 2013; however, that appears unlikely now due to delays in the siting and permitting of the line. Several landowners oppose this transmission line, including two large ranches. In November 2010, the ALJ issued a recommended decision granting the CPCN but proposing a significant refund obligation if the line was not heavily utilized ten years after it was in service. Several parties, including PSCo, filed exceptions to the recommended decision. The CPUC deliberated on the exceptions to the recommended decision and granted the CPCN without the refund obligation recommended by the ALJ. A written decision was issued on March 23, 2011. The matter remains subject to an application for reconsideration by two parties.

SmartGridCity™ CPCN — As part of the PSCo 2010 electric rate case, the CPUC included recovery of the revenue requirements associated with $45 million of capital and $4 million of annual O&M costs incurred by PSCo to develop and operate SmartGridCity™, subject to refund, and ordered PSCo to file for a CPCN for that project.

In February 2011, the CPUC approved the CPCN and allowed recovery of approximately $28 million of the capital cost and 100 percent of the O&M costs and ordered PSCo to file for a rate reduction in April 2011 to reflect the lower level of capital in rate base. The CPUC seeks additional information regarding the future plans to utilize SmartGridCity™ in an application to recover the additional capital. PSCo believes that it will be able to satisfy that requirement. On July 1, 2011, PSCo implemented an annual rate reduction of $2.8 million. PSCo plans to file the additional information in the fourth quarter of 2011.

Colorado DSM Strategic Issues Filing — The CPUC approved higher savings goals and a slightly higher financial incentive mechanism for PSCo's electric DSM energy efficiency programs starting in 2012. Savings goals will increase to 130 percent of the current goals and incentives will be awarded as one installment in the year following plan achievements. This is a revision to current CPUC policy of awarding incentives in two installments over a multi-year period. PSCo will also be able to earn an incentive on 11 percent of net economic benefits at an achievement level of 130 percent and a maximum annual incentive of $30 million.

Boulder, Colo. Franchise Agreement — The Boulder, Colo. City Council is exploring forming a municipal utility, instead of renewing their franchise agreement with PSCo. The franchise agreement expired in 2010; however, PSCo

continues to provide service under its CPUC certificate. The Boulder City Council originally expressed an interest in providing its residents with electricity derived primarily from renewable energy. PSCo had developed a proposal that would provide a substantially higher amount of renewable energy to Boulder, which the parties could not agree upon. Should the voters approve the formation of a municipal utility and the condemnation of the PSCo distribution system, PSCo will work to ensure that customers in Colorado recover the appropriate level of stranded costs and the value of the distribution system. At Dec. 31, 2010, the City of Boulder represented approximately 3.7 percent of PSCo's electric sales.

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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 (NERC) mandatory electric reliability standards. State and local agencies have jurisdiction over many of Xcel Energy Inc.'s utility 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, 2010. In addition to the matters discussed below, see Note 5 to the consolidated financial statements for a discussion of other regulatory matters.

NERC Electric Reliability Standards Compliance

Compliance Audits and Self Reports
In November 2010, the NSP System (the electric production and transmission system of NSP-Minnesota is managed as an integrated system with that of NSP-Wisconsin, jointly referred to as the NSP System), PSCo and SPS filed self-reports with the Midwest Reliability Organization (MRO), the Western Electricity Coordinating Council and Southwest Power Pool, Inc., respectively, regarding potential violations of certain NERC critical infrastructure protection standards (CIPS). Additional self-reports of potential violations of CIPS standards were filed in January 2011. Based on the issues identified with CIPS compliance, the utility subsidiaries submitted a mitigation plan that provides for a comprehensive review of its CIPS compliance programs. Whether and to what extent penalties may be assessed against the utility subsidiaries for the issues identified and self-reported to date is unclear.

In February and March 2011, the NSP System was subject to a comprehensive triennial audit by the MRO regarding compliance with various NERC mandatory reliability standards, including CIPS. The MRO found potential violations of seven standards; five are related to CIPS. The written MRO reports are now being completed, and none of the potential violations are expected to result in a material penalty.

NERC Compliance Investigations
In September 2007, portions of the NSP System and transmission systems west and north of the NSP System briefly islanded from the rest of the Eastern Interconnection as a result of a series of transmission line outages. In addition, service to approximately 790 MW of load was temporarily interrupted, primarily in Saskatchewan, Canada. In late 2010, NERC transferred responsibility for completing the compliance investigation to the MRO. The final outcome of the compliance investigation, and whether and to what extent penalties for violations may be assessed, is unknown at this time.

In February 2010, the NERC notified NSP-Minnesota that it was commencing a non-public investigation of NSP-Minnesota maintenance practices associated with insulating oil levels in bulk electric system substations, as the result of an anonymous complaint received by the NERC. In February 2011, NERC transferred responsibility for completing the compliance investigation to the MRO. The MRO reviewed the status of insulating oil levels during the triennial compliance audit in the first quarter 2011. In July 2011, the NERC issued a preliminary findings report with three potential violations of NERC reliability standards, which NSP-Minnesota expects to respond to in August 2011. The outcomes of the compliance investigations, and whether and to what extent the NERC or the MRO may seek to impose penalties for alleged violations, are unknown at this time.

FERC Tie Line Investigation — In October 2007, the FERC Office of Enforcement, the DOI, commenced a non-public investigation of the transmission service arrangements across the Lamar Tie Line, a transmission facility that connects PSCo and SPS. In July 2008, the DOI issued a preliminary report alleging Xcel Energy violated certain FERC policies, rules and approved tariffs that could result in material penalties under the FERC penalty guidelines. The

report does not constitute a finding by the FERC, which may accept, modify or reject any or all of the preliminary conclusions set forth in the report. Xcel Energy disagreed with the preliminary report and demonstrated compliance with applicable standards. In December 2010, the DOI initiated settlement discussions with Xcel Energy regarding possible resolution of the non-public investigation and settlement discussions are continuing. The final outcome of the DOI investigation and to what extent the FERC may seek to impose penalties for alleged violations is unknown at this time. The potential violations are not expected to have a material impact on Xcel Energy's financial condition, results of operations or cash flows.

Environmental, Legal and Other Matters

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

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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's Annual Report on Form 10-K for the year ended Dec. 31, 2010, 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, 2011, there have been no material changes to policies set forth in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2010.

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 as disclosed in Management's Discussion and Analysis and in Item 1A – Risk Factors in its Annual Report on Form 10-K for the year ended Dec. 31, 2010. 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 discussions 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 Xcel Energy's use of commodity derivatives. 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 debt and equity 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. As of June 30, 2011, there have been no material changes to market risks from those set forth in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2010.

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 products. 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)	2011	2010
Fair value of commodity trading net contract assets outstanding at Jan. 1	$20,249	$9,628
Contracts realized or settled during the period	(7,113)	(1,980)
Commodity trading contract additions and changes during period	10,544	7,750
Fair value of commodity trading net contract assets outstanding at June 30	$23,680	$15,398

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At June 30, 2011, 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	$5,363	$16,767	$433	$-	$22,563
	2	13	-	-	-	13
PSCo	1	298	941	-	-	1,239
		$5,674	17,708	$433	$-	$23,815

		Options				
(Thousands of Dollars)	Source of Fair Value	Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$(135)	$-	$-	$-	$(135)

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

2—Prices based on models and other valuation methods. These represent the fair value of positions calculated using internal models when directly and indirectly quoted external prices or prices derived from external sources are not available. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of commodity prices and contractual volumes. Market price uncertainty and other risks also are factored into the models.

At June 30, 2011, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.4 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.6 million.

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 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:

	Period Ended				
(Millions of Dollars)	June 30,	VaR Limit	Average	High	Low
2011	$ 0.32	$ 3.00	$ 0.18	$ 0.33	$ 0.08
2010	0.35	5.00	0.26	0.51	0.10

Interest Rate Risk — Xcel Energy Inc. and its subsidiaries are 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, 2011, a 100-basis-point change in the benchmark rate on Xcel Energy's variable rate debt would impact pretax interest expense by approximately $6.6 million annually, or approximately $1.6 million per quarter. 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, 2011, 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.

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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, 2011, a 10 percent increase in prices would have resulted in an increase in credit exposure of $141.3 million, while a decrease of 10 percent would have resulted in a decrease in credit exposure of $73.1 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 other 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, 2011. 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, 2011.

Commodity derivative assets and liabilities assigned to Level 3 consist primarily of FTRs, as well as forwards and options that are either long-term in nature or related to commodities and delivery points with limited observability. Level 3 commodity derivative assets and liabilities represent immaterial percentages of total assets and liabilities measured at fair value at June 30, 2011.

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 include $6.6 million and $2.6 million, respectively, of estimated fair values for FTRs held at June 30, 2011.

Determining the fair value of certain commodity forwards and options can require management to make use of subjective forward price and volatility forecasts for commodities and locations with limited observability, or subjective 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, 2011.

Nuclear Decommissioning Fund — Nuclear decommissioning fund assets assigned to Level 3 consist of asset-backed and mortgage-backed securities. To the extent appropriate, observable market inputs are utilized to estimate the fair value of these securities; however, less observable and subjective inputs are often significant to these valuations, including risk-based adjustments to the interest rate used to discount expected future cash flows, which include estimated prepayments of principal. Therefore, estimated fair values for all asset-backed and mortgage-backed securities totaling $83.3 million in the nuclear decommissioning fund at June 30, 2011 (approximately 5.8 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 component of a nuclear decommissioning regulatory asset.

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Liquidity and Capital Resources

Cash Flows

	Six Months Ended June 30,	
(Millions of Dollars)	2011	2010
Cash provided by operating activities	$1,123	$913

Cash provided by operating activities increased by $210 million for the first six months ended June 30, 2011, compared with the six months ended June 30, 2010. The increase was a result of changes in working capital primarily due to changes in accounts payable related to timing of payments, which were partially offset by changes in pension and employee benefit obligations mostly due to contributions of $134 million to Xcel Energy's pension plans in January 2011.

	Six Months Ended June 30,	
(Millions of Dollars)	2011	2010
Cash used in investing activities	$(1,090)	$(934)

Cash used in investing activities increased by $156 million for the first six months ended June 30, 2011, compared with the six months ended June 30, 2010. This increase was due to higher capital expenditures, primarily at NSP-Minnesota for the Monticello life cycle management and enhanced power uprate project and at SPS for the Jones Plant site in Lubbock, Texas.

	Six Months Ended June 30,	
(Millions of Dollars)	2011	2010
Cash used in financing activities	$(40)	$(20)

Cash used in financing activities increased by $20 million for the first six months ended June 30, 2011, compared with the six months ended June 30, 2010. The increase is primarily due to higher proceeds from short-term borrowings and lower repayments of long-term debt.

Capital Requirements

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

Regulation of Derivatives — In July 2010, President Obama signed financial reform legislation 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 as well as 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. However, the CFTC is still developing the appropriate regulatory rules under the act and, at this time, it is not clear whether Xcel Energy will qualify for the exemption. 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. If Xcel Energy does not meet the end user exception, the margin requirements could be significant. The full implications for Xcel Energy can not yet be determined until the various definitions and rulemakings are completed.

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 2010, Xcel Energy voluntarily contributed $34 million to one of its pension plans. In January 2011, Xcel Energy contributed $134 million, allocated across three of its pension plans. The January 2011 contribution raised the overall funded status from 84 percent at Dec. 31, 2010 to 88 percent with all other pension assumptions remaining constant. Based on updated valuation results received in March 2011 for the NCE Non-Bargaining Pension Plan, Xcel Energy made a required contribution of $3.3 million to the NCE Non-Bargaining Pension Plan in July 2011. Projected pension funding contributions for 2012, which will be dependent on several factors including realized asset performance, future discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $200 million.

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Capital Sources

Short-Term Funding Sources — Xcel Energy Inc. 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, 2011, approximately $20.7 million of cash was held in these liquid operating accounts.

Commercial Paper — Xcel Energy Inc., NSP-Minnesota, PSCo, SPS and NSP-Wisconsin each have individual commercial paper programs. NSP-Wisconsin received regulatory approval to initiate a commercial paper program in the first quarter of 2011. 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.

Commercial paper outstanding for Xcel Energy was as follows:

(Millions of Dollars)	Three Months Ended June 30, 2011	Twelve Months Ended Dec. 31, 2010
Borrowing limit	$ 2,450	$ 2,177
Amount outstanding at period end	656	466
Average amount outstanding	548	263
Maximum amount outstanding	692	653
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at end of period	0.35	0.40

Credit Facilities — During March of 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed new 4-year credit agreements. The total capacity of the credit facilities increased approximately $273 million to $2.45 billion. As of July 25, 2011, Xcel Energy Inc. and its utility subsidiaries had the following committed credit facilities available to meet its liquidity needs:

(Millions of Dollars)	Facility (b)	Drawn (a)	Available	Cash	Liquidity
Xcel Energy Inc.	$800.0	$332.1	$467.9	$0.3	$468.2
PSCo	700.0	208.8	491.2	0.7	491.9
NSP-Minnesota	500.0	87.1	412.9	0.2	413.1
SPS	300.0	161.0	139.0	0.3	139.3
NSP-Wisconsin	150.0	46.5	103.5	0.1	103.6
Total	$2,450.0	$835.5	$1,614.5	$1.6	$1,616.1

(a) Includes outstanding commercial paper and letters of credit.
(b) These credit facilities expire in March 2015.

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 from the utility subsidiaries and investments from Xcel Energy Inc. to the utility subsidiaries at market-based interest rates. The money pool balances are eliminated during consolidation.

The utility money pool arrangement does not allow Xcel Energy Inc. to borrow from the utility subsidiaries. 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.

Long-Term Borrowings — See Note 7 to the consolidated financial statements for further discussion on borrowings.

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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 addition to the periodic issuance and repayment of short-term debt, Xcel Energy Inc. and its utility subsidiaries' financing plans are as follows:

- PSCo plans to issue approximately $250 million of first mortgage bonds during the third quarter of 2011.
- SPS plans to issue approximately $200 million of bonds in the third quarter of 2011.
- Xcel Energy Inc. also anticipates issuing approximately $75 million of equity through the Dividend Reinvestment and Stock Purchase Plan (DSPP) and various benefit programs in 2011.

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

First Mortgage Bonds (FMB) Filing — In July 2011, the NMPRC issued an order approving SPS' request establish a FMB indenture, to create liens on its property for the purpose of securing principal and interest payments for FMBs to be issued under the indenture, and to enter into interest rate hedging agreements in support of interest rate locks and swaps in relation to the FMBs.

Off-Balance-Sheet Arrangements

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

Earnings Guidance

Xcel Energy's 2011 ongoing earnings guidance is $1.65 to $1.75 per share. Key assumptions related to ongoing earnings are detailed below:

- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales, adjusted for the sale of the Lubbock distribution assets, are projected to grow approximately 1.0 percent.
- Weather-adjusted retail firm natural gas sales are projected to decline 1.0 to 2.0 percent.
- Constructive outcomes in all rate case and regulatory proceedings.
- Rider revenue recovery is projected to be relatively flat.
- O&M expenses are projected to increase up to 4 percent.
- Depreciation expense is projected to increase $50 million to $60 million.
- Interest expense is projected to increase approximately $10 million.
- AFUDC — equity is projected to be relatively flat.
- The effective tax rate is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 486 million shares.

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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 Procedure

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in the 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, 2011, 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. After consultation with legal counsel, Xcel Energy has recorded an estimate of the probable cost of settlement or other disposition for such matters.

Additional Information

See Notes 5 and 6 of the consolidated financial statements for further discussion of legal proceedings, including Regulatory Matters and Commitments and Contingent Liabilities, which are hereby incorporated by reference. Reference also is made to Item 3 and Notes 13 and 14 of Xcel Energy Inc.'s consolidated financial statements in its Annual Report on Form 10-K for the year ended Dec. 31, 2010 for a description of certain legal proceedings presently pending.

Item 1A — RISK FACTORS

Except to the extent updated or described below, 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, 2010, which is incorporated herein by reference.

Operational Risks

Our subsidiary, NSP-Minnesota, is subject to the risks of nuclear generation.

NSP-Minnesota's two nuclear stations, Prairie Island and Monticello, subject it to the risks of nuclear generation, which include:

- The risks associated with use of radioactive material in the production of energy, the management, handling, storage and disposal of these radioactive materials and the current lack of a long-term disposal solution for radioactive materials;
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with nuclear operations; and
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives.

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The NRC has authority to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised NRC safety requirements could necessitate substantial capital expenditures or a substantial increase in operating expenses at NSP-Minnesota's nuclear plants. In addition, the Institute for Nuclear Power Operations reviews NSP-Minnesota's nuclear operations and nuclear generation facilities. Compliance with the Institute for Nuclear Power Operations' recommendations could result in substantial capital expenditures or a substantial increase in operating expenses.

If an incident did occur, it could have a material adverse effect on our results of operations or financial condition. Furthermore, the non-compliance of other nuclear facilities operators with applicable regulations or the occurrence of a serious nuclear incident at other facilities could result in increased regulation of the industry as a whole, which could then increase NSP-Minnesota's compliance costs and impact the results of operations of its facilities. The recent events at the nuclear facilities in Fukushima, Japan could result in increased regulation of the nuclear generation industry as a whole, and additional requirements with respect to emergency planning and demonstrated ability to operate nuclear facilities in the event of natural disasters or other events. This increased regulation could increase NSP-Minnesota's compliance costs and impact the results of operations of its nuclear facilities. Furthermore, these events could cause increased regulatory review and scrutiny by the NRC which could lead to delays in the process for obtaining required regulatory reviews and approvals.

NSP-Wisconsin's production and transmission system is operated on an integrated basis with NSP-Minnesota's production and transmission system, and NSP-Wisconsin may be subject to risks associated with NSP-Minnesota's nuclear generation.

Public Policy Risks

We may be subject to legislative and regulatory responses to climate change and emissions, with which compliance could be difficult and costly.

Increased public awareness and concern regarding climate change may result in more regional and/or federal requirements to reduce or mitigate the effects of GHGs. Numerous states have announced or adopted programs to stabilize and reduce GHGs, and federal legislation has been introduced in both houses of Congress. Internationally, other nations have already agreed to regulate emissions of GHGs pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," by 2012. In addition, in 2009, the U.S. submitted a non-binding GHG emission reduction target of 17 percent compared to 2005 levels pursuant to the Copenhagen Accord. Such legislative and regulatory responses related to climate change and new interpretations of existing laws through climate change litigation create financial risk as our electric generating facilities are likely to be subject to regulation under climate change laws introduced at either the state or federal level within the next few years.

The EPA has taken steps to regulate GHGs under the CAA. In December 2009, the EPA issued a finding that GHG emissions endanger public health and welfare, and that motor vehicle emissions contribute to the GHGs in the atmosphere. This endangerment finding created a mandatory duty for the EPA to regulate GHGs from light duty motor vehicles. In January 2011, new EPA permitting requirements became effective for GHG emissions of new and modified large stationary sources, which are applicable to construction of new power plants or power plant modifications that increase emissions above a certain threshold. The EPA has also announced that it will propose GHG regulations applicable to emissions from existing power plants in September 2011, with final standards to be issued in May 2012.

We are also currently a party to climate change lawsuits and may be subject to additional climate change lawsuits, including lawsuits similar to those described in Note 6 to the consolidated financial statements. An adverse outcome

in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties or damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

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Many of the federal and state climate change legislative proposals use a cap and trade policy structure, in which GHG emissions from a broad cross-section of the economy would be subject to an overall cap. Under the proposals, the cap becomes more stringent with the passage of time. The proposals establish mechanisms for GHG sources, such as power plants, to obtain "allowances" or permits to emit GHGs during the course of a year. The sources may use the allowances to cover their own emissions or sell them to other sources that do not hold enough emission allowances for their own operations. Proponents of the cap and trade policy believe it will result in the most cost effective, flexible emission reductions. There are many uncertainties, however, regarding when and in what form climate change legislation or regulation will be enacted. The impact of legislation and regulations, including a cap and trade structure, on us and our customers will depend on a number of factors, including whether GHG sources in multiple sectors of the economy are regulated, the overall GHG emissions cap level, the degree to which GHG offsets are allowed, the allocation of emission allowances to specific sources and the indirect impact of carbon regulation on natural gas and coal prices. While we do not have operations outside of the U.S., any international treaties or accords could have an impact to the extent they lead to future federal or state regulations. Another important factor is our ability to recover the costs incurred to comply with any regulatory requirements that are ultimately imposed. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us. If our regulators do not allow us to recover all or a part of the cost of capital investment or the O&M costs incurred to comply with the mandates, it could have a material adverse effect on our results of operations.

We are also subject to a significant number of proposed and potential rules that will impact our coal-fired and other generation facilities. These include, but are not limited to, rules associated with mercury, regional haze, ozone, ash management and cooling water intake systems. The costs of investment to comply with these rules could be substantial. We may not be able to timely recover all costs related to complying with regulatory requirements imposed on us.

Item 6 — EXHIBITS

* Indicates incorporation by reference

3.01*	Amended and Restated Articles of Incorporation of Xcel Energy Inc., as filed on May 20, 2011 (Exhibit 3.01 to Form 8-K of Xcel Energy file number 001-03034, dated May 18, 2011).
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 and 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, 2011 are formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Cash Flow, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Stockholder's Equity and Comprehensive Income, (v) Notes to Condensed Consolidated Financial Statements, and (vi) 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.

July 29, 2011

By: /s/ Teresa S. Madden
Teresa S. Madden
Vice President and Controller
(Principal Accounting Officer)

/s/ David M. Sparby
David M. Sparby
Vice President and Chief Financial Officer
(Principal Financial Officer)