XCEL ENERGY INC
Form 10-Q
October 28, 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 September 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 o

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

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

Class	Outstanding at Oct. 20, 2011
Common Stock, $2.50 par value	484,955,743 shares

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This Form 10-Q is filed by Xcel Energy Inc., also referred to herein as Xcel Energy Holding Co. 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). Xcel Energy Inc. and its consolidated subsidiaries is also referred to herein as Xcel Energy. 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 Sept. 30,		Nine Months Ended Sept. 30,	
	2011	2010	2011	2010
Operating revenues				
Electric	$2,619,424	$2,440,917	$6,777,793	$6,477,211
Natural gas	194,930	170,594	1,251,817	1,210,154
Other	17,244	17,276	56,750	56,648
Total operating revenues	2,831,598	2,628,787	8,086,360	7,744,013
Operating expenses				
Electric fuel and purchased power	1,150,252	1,110,781	3,071,493	3,085,347
Cost of natural gas sold and transported	87,107	66,571	793,539	774,647
Cost of sales — other	7,154	8,848	22,100	21,244
Other operating and maintenance expenses	532,962	509,634	1,575,159	1,507,247
Conservation and demand side management program expenses	71,280	60,861	212,075	174,451
Depreciation and amortization	242,329	221,671	696,316	639,303
Taxes (other than income taxes)	89,018	81,791	278,077	244,175
Total operating expenses	2,180,102	2,060,157	6,648,759	6,446,414
Operating income	651,496	568,630	1,437,601	1,297,599
Other income, net	2,550	27,450	8,295	30,134
Equity earnings of unconsolidated subsidiaries	7,423	7,670	22,813	22,433
Allowance for funds used during construction — equity	11,840	13,464	38,690	39,750
Interest charges and financing costs				
Interest charges — includes other financing costs of $6,279, $5,229, $17,724 and $15,386, respectively	148,011	144,849	438,703	430,134
Allowance for funds used during construction — debt	(6,301)	(6,323)	(21,575)	(20,635)
Total interest charges and financing costs	141,710	138,526	417,128	409,499
Income from continuing operations before income taxes	531,599	478,688	1,090,271	980,417
Income taxes	193,304	166,200	389,838	364,964
Income from continuing operations	338,295	312,488	700,433	615,453
Income (loss) from discontinued operations, net of tax	37	(182)	230	3,747
Net income	338,332	312,306	700,663	619,200
Dividend requirements on preferred stock	1,414	1,060	3,534	3,180
Premium on redemption of preferred stock	3,260	-	3,260	-
Earnings available to common shareholders	$333,658	$311,246	$693,869	$616,020

Weighted average common shares outstanding:				
Basic	485,344	460,471	484,640	459,816
Diluted	485,894	462,019	485,152	460,722
Earnings per average common share — basic:				
Income from continuing operations	$0.69	$0.68	$1.43	$1.33
Income from discontinued operations	-	-	-	0.01
Earnings per share	$0.69	$0.68	$1.43	$1.34
Earnings per average common share — diluted:				
Income from continuing operations	$0.69	$0.67	$1.43	$1.33
Income from discontinued operations	-	-	-	0.01
Earnings per share	$0.69	$0.67	$1.43	$1.34
Cash dividends declared per common share	$0.26	$0.25	$0.77	$0.75

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)

	Nine Months Ended Sept. 30, 2011	Nine Months Ended Sept. 30, 2010
Operating activities		
Net income	$700,663	$619,200
Remove income from discontinued operations	(230)	(3,747)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	709,936	648,089
Conservation and demand side management program amortization	7,979	18,694
Nuclear fuel amortization	75,292	78,150
Deferred income taxes	389,355	325,530
Amortization of investment tax credits	(4,740)	(4,782)
Allowance for equity funds used during construction	(38,690)	(39,750)
Equity earnings of unconsolidated subsidiaries	(22,813)	(22,433)
Dividends from unconsolidated subsidiaries	25,481	23,821
Share-based compensation expense	31,943	27,272
Net realized and unrealized hedging and derivative transactions	14,537	(61,136)
Changes in operating assets and liabilities:		
Accounts receivable	(33,649)	31,876
Accrued unbilled revenues	155,854	159,769
Inventories	(47,207)	(25,520)
Other current assets	60,216	32,201
Accounts payable	(82,681)	(283,123)
Net regulatory assets and liabilities	134,338	85,128
Other current liabilities	5,969	(45,984)
Pension and other employee benefit obligations	(136,538)	(9,481)
Change in other noncurrent assets	21,211	(231)
Change in other noncurrent liabilities	(42,108)	(27,220)
Net cash provided by operating activities	1,924,118	1,526,323
Investing activities		
Utility capital/construction expenditures	(1,604,206)	(1,561,987)
Allowance for equity funds used during construction	38,690	39,750
Merricourt refund	101,261	-
Merricourt deposit	(90,833)	-
Purchase of investments in external decommissioning fund	(1,741,907)	(3,309,093)
Proceeds from the sale of investments in external decommissioning fund	1,741,909	3,314,356
Investment in WYCO Development LLC	(1,768)	(6,119)
Change in restricted cash	(99,972)	91
Other investments	(4,129)	2,044
Net cash used in investing activities	(1,660,955)	(1,520,958)
Financing activities		
Repayment of short-term borrowings, net	(416,400)	(419,000)

Proceeds from issuance of long-term debt	688,686	1,038,368
Repayment of long-term debt, including reacquisition premiums	(104,525)	(200,452)
Proceeds from issuance of common stock	6,164	5,869
Dividends paid	(351,370)	(322,187)
Net cash (used in) provided by financing activities	(177,445)	102,598
Net increase in cash and cash equivalents	85,718	107,963
Cash and cash equivalents at beginning of period	108,437	115,648
Cash and cash equivalents at end of period	$194,155	$223,611
Supplemental disclosure of cash flow information:		
Cash paid for interest, net of amounts capitalized	$(405,111)	$(389,719)
Cash received (paid) for income taxes, net	53,567	(17,410)
Supplemental disclosure of non-cash investing and financing transactions:		
Property, plant and equipment additions in accounts payable	$136,236	$62,663
Issuance of common stock for reinvested dividends and 401(k) plans	55,319	48,685

See Notes to Consolidated Financial Statements

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

	Sept. 30, 2011	Dec. 31, 2010
Assets		
Current assets		
Cash and cash equivalents	$194,155	$108,437
Restricted cash	100,007	-
Accounts receivable, net	752,123	718,474
Accrued unbilled revenues	552,837	708,691
Inventories	608,007	560,800
Regulatory assets	412,211	388,541
Derivative instruments	50,281	54,079
Prepayments and other	191,852	193,621
Total current assets	2,861,473	2,732,643
Property, plant and equipment, net	21,729,488	20,663,082
Other assets		
Nuclear decommissioning fund and other investments	1,399,527	1,476,435
Regulatory assets	2,224,509	2,151,460
Derivative instruments	158,362	184,026
Other	164,495	180,044
Total other assets	3,946,893	3,991,965
Total assets	$28,537,854	$27,387,690
Liabilities and Equity		
Current liabilities		
Current portion of long-term debt	$462,414	$55,415
Short-term debt	50,000	466,400
Accounts payable	837,259	979,750
Regulatory liabilities	309,032	156,038
Taxes accrued	250,135	254,320
Accrued interest	162,374	163,907
Dividends payable	127,497	122,847
Derivative instruments	125,514	61,745
Other	328,958	276,111
Total current liabilities	2,653,183	2,536,533
Deferred credits and other liabilities		
Deferred income taxes	3,809,638	3,390,027
Deferred investment tax credits	88,197	92,937
Regulatory liabilities	1,133,747	1,179,765
Asset retirement obligations	1,293,424	969,310
Derivative instruments	265,481	285,986
Customer advances	256,764	269,087
Pension and employee benefit obligations	829,364	962,767

Other	221,616	249,635
Total deferred credits and other liabilities	7,898,231	7,399,514
Commitments and contingent liabilities		
Capitalization		
Long-term debt	9,450,157	9,263,144
Preferred stockholders' equity	104,980	104,980
Common stock – $2.50 par value per share	1,212,369	1,205,834
Additional paid in capital	5,280,463	5,229,075
Retained earnings	2,019,440	1,701,703
Accumulated other comprehensive loss	(80,969)	(53,093)
Total common stockholders' equity	8,431,303	8,083,519
Total liabilities and equity	$28,537,854	$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 Sept. 30, 2011 and 2010						
Balance at June 30, 2010	459,627	$1,149,069	$4,800,841	$1,493,997	$ (52,085)	$ 7,391,822
Net income				312,306		312,306
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $236					510	510
Net derivative instrument fair value changes, net of tax of $554					784	784
Unrealized gain - marketable securities, net of tax of $37					54	54
Comprehensive income for the period						313,654
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(116,754)		(116,754)
Issuances of common stock	478	1,192	7,805			8,997
Share-based compensation			9,018			9,018
Balance at Sept. 30, 2010	460,105	$1,150,261	$4,817,664	$1,688,489	$ (50,737)	$ 7,605,677
Balance at June 30, 2011	484,543	$1,211,356	$5,261,687	$1,812,505	$ (50,983)	$ 8,234,565
Net income				338,332		338,332
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $515					743	743
Net derivative instrument fair value changes, net of tax of $(20,142)					(30,788)	(30,788)
Unrealized gain - marketable securities, net of tax of $41					59	59
Comprehensive income for the period						308,346
Dividends declared:						
Cumulative preferred stock				(1,414)		(1,414)
Common stock				(126,723)		(126,723)
				(3,260)		(3,260)

Premium on redemption of preferred stock						
Issuances of common stock	405	1,013	8,738			9,751
Share-based compensation			10,038			10,038
Balance at Sept. 30, 2011	484,948	$1,212,369	$5,280,463	$2,019,440	$ (80,969)	$ 8,431,303

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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
Nine Months Ended Sept. 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				619,200		619,200
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $852					1,385	1,385
Net derivative instrument fair value changes, net of tax of $(1,711)					(2,371)	(2,371)
Unrealized gain - marketable securities, net of tax of $(29)					(42)	(42)
Comprehensive income for the period						618,172
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(346,732)		(346,732)
Issuances of common stock	2,596	6,488	23,437			29,925
Share-based compensation			24,247			24,247
Balance at Sept. 30, 2010	460,105	$1,150,261	$4,817,664	$1,688,489	$ (50,737)	$ 7,605,677
Balance at Dec. 31, 2010	482,334	$1,205,834	$5,229,075	$1,701,703	$ (53,093)	$ 8,083,519
Net income				700,663		700,663
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $1,591					2,290	2,290
Net derivative instrument fair value changes, net of tax of $(19,750)					(30,276)	(30,276)
Unrealized loss - marketable securities, net of tax of $76					110	110
Comprehensive income for the period						672,787
Dividends declared:						
Cumulative preferred stock				(3,534)		(3,534)
Common stock				(376,132)		(376,132)
				(3,260)		(3,260)

Premium on redemption of preferred stock						
Issuances of common stock	2,614	6,535	18,462			24,997
Share-based compensation			32,926			32,926
Balance at Sept. 30, 2011	484,948	$1,212,369	$5,280,463	$2,019,440	$ (80,969)	$ 8,431,303

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 Sept. 30, 2011 and Dec. 31, 2010; the results of its operations and changes in stockholders' equity for the three and nine months ended Sept. 30, 2011 and 2010; and its cash flows for the nine months ended Sept. 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 Sept. 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 on an annual basis have been condensed or omitted pursuant to such rules and regulations. For further information, refer to the consolidated financial statements and notes thereto, included in the Xcel Energy Inc. Annual Report on Form 10-K for the year ended Dec. 31, 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 presentation guidance to have a material impact on its consolidated financial statements.

Multiemployer Plans — In September 2011, the FASB issued Multiemployer Plans (Subtopic 715-80) — Disclosures about an Employer's Participation in a Multiemployer Plan (ASU No. 2011-09), which updates the Codification to require certain disclosures about an entity's involvement with multiemployer pension and other postretirement benefit plans. These updates do not affect recognition and measurement guidance for an employer's participation in multiemployer plans, but rather require additional disclosure such as the nature of multiemployer plans and the employer's participation, contributions to the plans and details regarding significant plans. These updates to the Codification are effective for annual periods ending after Dec. 15, 2011. Xcel Energy does not expect the implementation of this disclosure guidance to have a material impact on its consolidated financial statements.

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3. Selected Balance Sheet Data

(Thousands of Dollars)	Sept. 30, 2011	Dec. 31, 2010
Accounts receivable, net		
Accounts receivable	$806,360	$773,037
Less allowance for bad debts	(54,237)	(54,563)
	$752,123	$718,474
Inventories		
Materials and supplies	$205,736	$196,081
Fuel	205,126	188,566
Natural gas	197,145	176,153
	$608,007	$560,800
Property, plant and equipment, net		
Electric plant	$26,437,558	$24,993,582
Natural gas plant	3,574,976	3,463,343
Common and other property	1,536,759	1,555,287
Plant to be retired (a)	182,487	236,606
Construction work in progress	1,169,746	1,186,433
Total property, plant and equipment	32,901,526	31,435,251
Less accumulated depreciation	(11,484,612)	(11,068,820)
Nuclear fuel	1,928,912	1,837,697
Less accumulated amortization	(1,616,338)	(1,541,046)
	$21,729,488	$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 2007 federal income tax return expired in September 2011. The statute of limitations applicable to Xcel Energy's 2008 federal income tax return expires in September 2012. The Internal Revenue Service (IRS) commenced an examination of tax years 2008 and 2009 in the third quarter of 2010. As of Sept. 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 Sept. 30, 2011, Xcel Energy's earliest open tax years that are subject to examination by state taxing authorities in its major operating jurisdictions were as follows:

State	Year

Colorado	2006
Minnesota	2007
Texas	2007
Wisconsin	2006

As of Sept. 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)	Sept. 30, 2011	Dec. 31, 2010
Unrecognized tax benefit — Permanent tax positions	$3.5	$5.9
Unrecognized tax benefit — Temporary tax positions	31.7	34.6
Unrecognized tax benefit balance	$35.2	$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)	Sept. 30, 2011	Dec. 31, 2010
NOL and tax credit carryforwards	$(33.3)	$(38.0)

The decrease in the unrecognized tax benefit balance for the nine months ended Sept. 30, 2011 of $5.3 million was due primarily to the resolution of certain federal audit matters and adjustments for prior year's 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 by up to approximately $24 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 Sept. 30, 2011 and Dec. 31, 2010 were not material. No amounts were accrued for penalties related to unrecognized tax benefits as of Sept. 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 and an additional increase of $48.3 million, or 1.81 percent in 2012. The rate filing was based on a 2011 forecast test year 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.

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 June 2011, NSP-Minnesota revised its requested rate increase to $122.8 million, reflecting a revised ROE of 10.85 percent and other adjustments. The Division of Energy Resources (DOER) revised its recommended rate increase to approximately $84.7 million in 2011 and an additional rate increase of $34 million in 2012, reflecting an ROE of 10.37 percent. The primary differences between the NSP-Minnesota requested rate increase and the DOER updated recommendation are associated with ROE and compensation related issues.

In August 2011, NSP-Minnesota submitted supplemental testimony, revising its requested rate increase to approximately $122 million for 2011 and a 2012 step increase of approximately $29 million. The revisions are due to NSP-Minnesota's decision to delay the Monticello nuclear plant extended power uprate from the fall of 2011 to the fall of 2012. Subsequently, NSP-Minnesota anticipates prolonging the extended power uprate to the spring 2013 refueling outage.

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NSP-Minnesota has recorded a provision for revenue subject to refund of approximately $27 million for the first nine months of 2011, of which $12 million was recorded during the three months ended Sept. 30, 2011. The provision reflects an outcome that is consistent with the DOER position on various issues.

The MPUC decision is expected in the first quarter of 2012.

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 in 2011 and a step increase of $4.2 million, or 2.6 percent in 2012. 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.

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.

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.

In September 2011, NSP-Minnesota reached a settlement with the NDPSC Advocacy Staff. If approved, the settlement would result in a rate increase of $13.7 million in 2011 and an additional step increase of $2.0 million in 2012, based on a 10.4 percent ROE and black box settlement for all other issues. To address 2011 sales coming in below test year projections, the settlement includes a true-up to 2012 non-fuel revenues plus the settlement rate increase.

In October 2011, the NDPSC held hearings on the settlement. An NDPSC decision is expected in the fourth quarter of 2011 with final rates expected to be implemented in the first quarter of 2012.

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. 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 nuclear plant life cycle management and extended power uprate project that is not reflected in the test year.

As a result of delays in the South Dakota rate case process, NSP-Minnesota anticipates requesting implementation of interim rates beginning Jan. 1, 2012 in the fourth quarter of 2011. A final decision on interim rates is expected in the first quarter of 2012.

Electric, Purchased Gas and Resource Adjustment Clauses

Conservation Improvement Program (CIP) Rider — CIP expenses are recovered through base rates and a rider that is adjusted annually. Under the 2010 electric CIP rider request approved by the MPUC in October 2010, NSP-Minnesota recovered $67.3 million through the rider during November 2010 to September 2011. This is in addition to $48.5 million recovered through base rates. NSP-Minnesota recovered $20.6 million through the natural gas CIP rider approved in November 2010, during December 2010 to September 2011. This is in addition to $3.3 million recovered in base rates.

In 2011, NSP-Minnesota filed its annual rider petitions requesting recovery of $84.8 million of electric CIP expenses and financial incentives and $13.6 million of natural gas CIP expenses and financial incentives to be recovered during October 2011 through September 2012. This proposed recovery through the riders is in addition to an estimated $52.6 million and $3.8 million through electric and gas base rates, respectively.

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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 and bonus solar rebates. In October 2010, NSP-Minnesota filed its annual request to recover $19.2 million in expenses for 2011. In June 2011, the MPUC approved recovery of the costs requested.

In October 2011, NSP-Minnesota filed its annual request to recover $17.3 million in expenses for 2012.

Transmission Cost Recovery (TCR) Rider — The MPUC has approved a TCR rider that allows annual adjustments to retail electric rates to provide recovery of certain incremental transmission investments between rate cases. In September 2011, the MPUC approved a TCR rider expected to recover $11.5 million in 2011, as well as $22.3 million in 2012. Rates are expected to be effective beginning Nov. 1, 2011.

Renewable Energy Standard (RES) Rider — The MPUC has approved a RES rider to recover the costs for utility-owned projects implemented in compliance with the Minnesota RES. In September 2011, the MPUC approved a RES rider to recover $40.8 million during 2011. The MPUC also ordered that $9.5 million of over-recovery be credited to customers during November 2011, and to begin collecting forecasted Dec. 1, 2011 through Dec. 31, 2012 revenue requirements of $43.1 million beginning Dec. 1, 2011.

Annual Automatic Adjustment Report — In September 2011, NSP-Minnesota filed its annual electric and natural gas automatic adjustment reports for July 1, 2010 through June 30, 2011. During that time period, $822.8 million in fuel and purchased energy costs were recovered from Minnesota electric customers through the fuel clause adjustment. In addition, approximately $371.6 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 automatic adjustment report in June 2011 for recovery of $354.5 million, and the report is pending MPUC action. The 2009/2010 electric automatic adjustment report for recovery of $749.5 million is pending DOER comments and MPUC action.

The MPUC approved the 2008/2009 gas automatic adjustment report in March 2011 for recovery of $500.8 million. Approval of the 2008/2009 electric automatic adjustment report for recovery of $803.6 million is pending DOER comments and MPUC action.

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, an equity ratio of 52.54 percent, an electric rate base of approximately $718 million and a natural gas rate base of $84 million.

In October 2011, the PSCW Staff filed testimony and recommended an electric rate increase of $18.1 million and a natural gas rate increase of $2.9 million, based on an ROE of 10.3 percent. Rebuttal testimony supporting NSP-Wisconsin’s recommendations was filed on Oct. 21, 2011.

Evidentiary hearings are scheduled for Nov. 2, 2011. NSP-Wisconsin anticipates a PSCW decision in the fourth quarter of 2011 with new rates effective Jan. 1, 2012.

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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 10.9 percent ROE, a rate base of $1.1 billion and an equity ratio of 57.1 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 August 2011, the CPUC approved a comprehensive settlement that PSCo reached with CPUC Staff and the Colorado Office of Consumer Counsel (OCC) to increase rates by $12.8 million, to institute rider recovery of future pipeline integrity costs, and to remove gas in 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 underground 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 went into effect in September 2011. The rider for pipeline integrity costs is expected to go into effect on Jan. 1, 2012 and is expected to recover an estimated $31.5 million of incremental revenue in 2012.

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

PSCo Wholesale Electric Rate Case — In February 2011, PSCo filed with the FERC to change Colorado wholesale electric rates to formula based rates with an expected annual increase of $16.1 million for 2011. The request was based on a 2011 forecast test year, a 10.9 percent ROE, a rate base of $407.4 million and an equity ratio of 57.1 percent. The formula rate would be estimated each year for the following year and then would be trued up to actual costs after the conclusion of the calendar year. A decision is expected in the first quarter of 2012.

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 annual 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. In the second quarter of 2011, PSCo credited approximately $37 million against the RESA regulatory asset balance.

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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. In September 2011, parties filed answer testimony requesting the CPUC approve margin sharing of 8 percent to 25 percent to PSCo for deliveries outside of California and 8 percent to 35 percent for deliveries inside of California. Hearings were held in October 2011 and a decision is expected in the first quarter of 2012.

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 was 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.

In September 2011, the parties filed an unopposed black box settlement to resolve all issues in the case. If the settlement is approved by the NMPRC, base rates will increase by $13.5 million. SPS has agreed not to file another base rate case until Dec. 3, 2012 with new final rates from the result of such case not going into effect until Jan. 1, 2014 (Settlement Period), provided however, that SPS can request to implement interim rates if the NMPRC standard for interim rates is met. During the Settlement Period, rates are to remain fixed aside from the continued operation of the fuel adjustment clause and certain exceptions for energy efficiency, a rider for an approved renewable portfolio standard regulatory asset, and actual costs incurred for environmental regulations with an effective date after Dec. 31, 2010.

In October 2011, the NMPRC held hearings on the settlement. A decision by the NMPRC is expected by year-end and final rates are expected to be implemented effective Jan. 1, 2012.

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 Sept. 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.

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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 do 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)	Sept. 30, 2011	Dec. 31, 2010
Current assets	$ 3,711	$ 3,794
Property, plant and equipment, net	95,618	97,602
Other noncurrent assets	8,267	8,236
Total assets	$ 107,596	$ 109,632
Current liabilities	$ 13,400	$ 11,884
Mortgages and other long-term debt payable	51,204	53,195
Other noncurrent liabilities	8,513	8,333
Total liabilities	$ 73,117	$ 73,412

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

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

(Millions of Dollars)	Sept. 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	31.2	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 is alleged to be a PRP that sent hazardous materials and wastes. At Sept. 30, 2011 and Dec. 31, 2010, the liability for the cost of remediating these sites was estimated to be $107.3 million and $104.0 million, respectively, of which $7.3 million and $5.7 million, respectively, was considered to be a current liability.

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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. 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. Those settlement negotiations are ongoing.

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 performed a site investigation, and has concluded that materials typically associated with the operation of MGPs are present in soils and groundwater at the site. NSP-Wisconsin has submitted a proposed remediation action plan to the WDNR for the remediation of the site. The ultimate scope and costs of such remediation will not be fully determinable until a remediation action plan is approved by the WDNR. NSP-Wisconsin has recorded a liability of $2.2 million based upon potential remediation, design and outside consultant costs.

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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) Regulation — 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.

GHG New Source Performance Standard Proposal — The EPA plans to propose GHG regulations applicable to emissions from new and existing power plants under the Clean Air Act (CAA). The EPA had planned to release its proposal in September 2011, but has delayed it without establishing a new proposal date.

Cross State Air Pollution Rule (CSAPR) — On July 7, 2011, the EPA issued its CSAPR. The rule, previously called the Clean Air Transport Rule (CATR), 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 CATR 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. Xcel Energy may comply by reducing emissions and/or purchasing allowances. The CSAPR is a final rule and requires compliance beginning in 2012.

At this time, Xcel Energy believes that the CSAPR will ultimately require the installation of additional emission controls on some of SPS' coal-fired electric generating units. SPS is still evaluating compliance options, however SPS believes the cost of any required capital investment will be recoverable from customers. Because the CSAPR requires compliance in 2012, SPS will 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. Texas was not included in the annual SO2 and NOx reductions requirements of the proposed rule. Without additional notice, the EPA determined in the final CSAPR that Texas would be required to reduce SO2 emissions, comply with the annual NOx emission limits, and be in compliance beginning in 2012. Since the final CSAPR was published on Aug. 8, 2011, SPS has analyzed compliance scenarios and concluded that, unless a new CSAPR allowance market develops quickly, SPS would have to redispatch its system to run its natural gas plants as base load units. Additionally, SPS would have to substantially reduce coal plant operations in order to comply with the CSAPR using the emission allowances allocated to SPS by the EPA, which requires, for example, a 46 percent reduction in SO2 emissions in 2012. SPS has estimated that such a substantial change in operations could cost up to $250 million in 2012, mostly due to increased fuel costs, as well as increase risk to reliability on its system. SPS also expects that in order to comply with the CSAPR, its entire system will have to reduce NOx emissions by 33 percent in 2012. SPS expects it will be able to recover these costs through regulatory mechanisms and it does not expect a material impact on its results of operations.

On Oct. 6, 2011, the EPA proposed two relevant changes to revise the CSAPR. SPS' initial analysis indicates that this proposed rule, if finalized, would not appreciably change the CSAPR's adverse impact on SPS and its customers, because SPS is constrained by both NOx and SO2 emission reduction obligations under the rule. SPS remains concerned that the allowance market will not develop to the extent necessary to defray the cost and reliability risks associated with the CSAPR. SPS has preliminarily concluded that the proposal may reduce the cost of compliance by a modest amount if finalized, but it would not significantly alleviate the risks associated with the 2012 compliance date.

SPS filed two petitions with the EPA for reconsideration and stay of the CSAPR as it applies to the requirement for annual emission reductions in Texas. In addition, SPS filed a petition for review of the CSAPR with the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) that challenges the inclusion of Texas in the CSAPR's annual reduction programs and the 2012 compliance date. Along with the petition for review, SPS also filed a motion for stay of the CSAPR with the D.C. Circuit. SPS expects that the court will rule on the motion for stay by the end of 2011. Success in these legal actions could reduce SPS' costs to comply with the CSAPR substantially. SPS expects it will be able to recover legal costs through regulatory mechanisms and it does not expect a material impact on its results of operations.

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To comply with the CSAPR in Minnesota, NSP-Minnesota currently intends to utilize a combination of emissions reductions through control technology upgrades at NSP-Minnesota's Sherco plant, including the installation of a sparger system for SO2 control, at an estimated cost of $10 million total in 2012 and 2013, and system operating changes to the Black Dog and the Sherco plants. If available, NSP-Minnesota will also consider allowance purchases. In addition, NSP-Minnesota has filed a petition for reconsideration with the EPA and a petition for review of the CSAPR with the D.C. Circuit seeking the allocation of additional emission allowances to NSP-Minnesota. NSP-Minnesota contends that the EPA's method of allocating allowances arbitrarily resulted in fewer allowances for its Riverside and High Bridge plants than should have been awarded to reflect their operations during the baseline period, which included coal-fired operations prior to their conversion to natural gas. If successful, additional allowances would reduce NSP-Minnesota's costs to comply with the reductions imposed by the CSAPR.

To comply with the CSAPR in Wisconsin, NSP-Wisconsin currently intends to make a combination of system operating changes and allowance purchases, if available. NSP-Wisconsin estimates the cost of compliance to be $0.2 million, and it expects the cost of any required capital investment will be recoverable from customers.

Xcel Energy continues to evaluate its compliance strategy. Xcel Energy believes the cost of any required capital investment, allowance purchases or costs associated with redispatch 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 D.C. Circuit 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. In 2011, the EPA finalized the CSAPR to replace CAIR 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. At Sept. 30, 2011, the estimated annual CAIR NOx allowance cost for SPS was $0.1 million. At Sept. 30, 2011, the estimated annual CAIR NOx allowance cost for NSP-Wisconsin was $0.1 million. At the end of 2011, the CAIR will end and compliance efforts will transition to the CSAPR beginning in 2012. No allowance trading is allowed between the CAIR and CSAPR programs.

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 has indicated that it intends to issue the final rule by December 2011. Xcel Energy anticipates that the EPA will require affected facilities to demonstrate compliance within three to four years. Xcel Energy believes these costs would be recoverable through regulatory mechanisms, and it does not expect a material impact on its results of operations.

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.

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.

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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 Sept. 30, 2011, the estimated annual testing and study cost is $0.5 million. NSP-Minnesota projects installation costs of $12.0 million for the 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 NSP-Wisconsin's Bay Front units 1 and 2. The estimated cost of $9.0 million per unit, which is currently targeted for 2014, is dependent on the outcome of the reconsideration proceedings to comply with these rules.

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 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 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.

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.

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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 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 provided comments to the proposed rule. 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 Generating 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. It is not known whether any costs would be incurred as a result of this notice.

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, the 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 Sherco 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. It is not known whether any costs would be incurred as a result of this notice.

Legal Contingencies

Lawsuits and claims arise in the normal course of business. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material effect on Xcel Energy's 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 for the Southern District of New York against the following utilities, including Xcel Energy, to force reductions in carbon dioxide (CO_2) emissions: American Electric Power Co., Southern Co., Cinergy Corp. (merged into Duke Energy Corporation) and Tennessee Valley Authority. The lawsuits allege that CO_2 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 CO_2 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. In June 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. In September 2011, plaintiffs submitted a letter to the Second Circuit seeking to voluntarily dismiss the complaint.

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 CO_2 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. Oral arguments are set for Nov. 28, 2011. 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 a year after their initial lawsuit was dismissed, plaintiffs in this purported class action lawsuit filed a second lawsuit against more than 85 utility, oil, chemical and coal companies in U.S. District Court in Mississippi. The complaint alleges defendants' CO_2 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. This decision was subsequently affirmed by the Colorado Supreme Court in June 2011. On Sept. 16, 2011, Qwest filed a petition for a Writ of Certiorari with the U.S. Supreme Court. No accrual has been recorded for this matter.

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, alleged, among other things, that PSCo mismanaged the construction of Comanche Unit 3. Shaw further claimed that this alleged mismanagement caused delays and damages. The complaint also alleged that Xcel Energy Inc. and related entities guaranteed Shaw $10 million in future profits under the terms of a 2003 settlement agreement. Shaw alleged that it will not receive the $10 million to which it is entitled. Accordingly, Shaw sought an amount up to $10 million related to the 2003 settlement agreement. In total, Shaw sought approximately $144 million in damages.

PSCo denied 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 failed to discharge its contractual obligations and caused delays, and that PSCo is entitled to liquidated damages and excess costs incurred. In total, PSCo sought 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.

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In November 2010, a jury returned a verdict on the issues raised in the first complaint 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 in April 2011. This litigation is not expected to have a material 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. On Sept. 16, 2011, the U.S. District Court denied the motion to dismiss. The trial is set to begin in late 2012 or early 2013. No accrual has been recorded for this matter.

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's (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 received the initial $100 million payment in August 2011, of which $15 million is expected to be allocated to NSP-Wisconsin through the interchange agreement. 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. As of Sept. 30, 2011, the payment received from the DOE has been recorded as restricted cash and a regulatory liability.

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.

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

(Millions of Dollars)	Three Months Ended Sept. 30, 2011	Twelve Months Ended Dec. 31, 2010
Borrowing limit	$ 2,450	$ 2,177
Amount outstanding at period end	50	466
Average amount outstanding	477	263
Maximum amount outstanding	824	653
Weighted average interest rate, computed on a daily basis	0.36%	0.36%
Weighted average interest rate at period end	0.34	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 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed new four-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.
- 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 Sept. 30, 2011 as evidenced by the table below:

	Debt-to-Total Capitalization Ratio
NSP-Minnesota	48 %
PSCo	45
SPS	48
Xcel Energy	54
NSP-Wisconsin	48

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.

- The Xcel Energy Inc. credit facility has a cross-default provision that provides Xcel Energy Inc. will be in default on its borrowings under the facility if it or any of its subsidiaries, except NSP-Wisconsin as long as its total assets do not comprise more than 15 percent of Xcel Energy's consolidated total assets, default on certain indebtedness in an aggregate principal amount exceeding $75 million.
- The interest rates under these lines of credit are based on the Eurodollar rate or an alternate base rate, plus a borrowing margin of 0 to 200 basis points per year based on the applicable credit ratings.
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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.

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At Sept. 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	$ 22.1	$ 777.9
PSCo	700.0	4.8	695.2
NSP-Minnesota	500.0	7.1	492.9
SPS	300.0	-	300.0
NSP-Wisconsin	150.0	28.0	122.0
Total	$ 2,450.0	$ 62.0	$ 2,388.0

(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 facilities outstanding at Sept. 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 Sept. 30, 2011 and Dec. 31, 2010, there were $12.0 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 facilities were outstanding at Sept. 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.

Long-Term Borrowings

In September 2011, Xcel Energy Inc. issued $250 million of 4.80 percent senior unsecured notes due Sept. 15, 2041. Xcel Energy Inc. added the net proceeds from the sale of the notes to its general funds and used the proceeds to repay short-term debt and for general corporate purposes.

In August 2011, PSCo issued $250 million of 4.75 percent first mortgage bonds due Aug. 15, 2041. PSCo used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term debt borrowings incurred to fund daily operational needs. The balance of the net proceeds was used for general corporate purposes.

In August 2011, SPS issued $200 million of 4.50 percent first mortgage bonds due Aug. 15, 2041. SPS used a portion of the net proceeds from the sale of the first mortgage bonds to repay short-term debt borrowings incurred to fund daily operational needs and to redeem $57.3 million of the outstanding 5.75 percent Pollution Control Revenue Refunding Bonds due Sept. 1, 2016. The balance of the net proceeds was used for general corporate purposes.

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.

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.

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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 each 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.

Interest rate derivatives — The fair value of interest rate derivatives are based on broker quotes utilizing market interest rate curves.

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.

Unrealized gains for the decommissioning fund were $54.4 million and $82.5 million at Sept. 30, 2011 and Dec. 31, 2010, respectively, and unrealized losses and amounts recorded as other-than-temporary impairments were $140.9 million and $65.2 million at Sept. 30, 2011 and Dec. 31, 2010, respectively.

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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 Sept. 30, 2011 and Dec. 31, 2010:

	Sept. 30, 2011				
		Fair Value			
(Thousands of Dollars)	Cost	Level 1	Level 2	Level 3	Total
Nuclear decommissioning fund (a)					
Cash equivalents	$77,875	$75,370	$2,505	$-	$77,875
Commingled funds	296,629	-	267,511	-	267,511
International equity funds	63,781	-	56,956	-	56,956
Debt securities:					
Government securities	163,744	-	168,798	-	168,798
U.S. corporate bonds	174,314	-	176,450	-	176,450
Foreign securities	35,434	-	35,558	-	35,558
Municipal bonds	43,652	-	46,229	-	46,229
Asset-backed securities	10,251	-	-	10,246	10,246
Mortgage-backed securities	51,674	-	-	54,815	54,815
Equity securities:					
Common stock	440,855	377,253	-	-	377,253
Total	$1,358,209	$452,623	$754,007	$65,061	$1,271,691

(a) Reported in nuclear decommissioning fund and other investments on the consolidated balance sheet, which also includes $95.5 million of equity investments in unconsolidated subsidiaries and $32.3 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 Sept. 30,			
	2011		2010	
(Thousands of Dollars)	Mortgage-Backed Securities	Asset-Backed Securities	Mortgage-Backed Securities	Asset-Backed Securities
Balance at July 1	$ 62,271	$ 21,004	$ 65,059	$ 40,067
Purchases	1,972	9,496	-	-
Settlements	(8,978)	(19,443)	(1,949)	(5,744)
(Losses) gains recorded as regulatory assets and liabilities	(450)	(811)	1,286	171
Balance at Sept. 30	$ 54,815	$ 10,246	$ 64,396	$ 34,494

	Nine Months Ended Sept. 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	101,037	10,252	46,477	36,042
Settlements	(117,435)	(32,559)	(68,124)	(13,853)
(Losses) gains recorded as regulatory assets and liabilities	(1,376)	(621)	4,854	387
Balance at Sept. 30	$ 54,815	$ 10,246	$ 64,396	$ 34,494

The following table summarizes the final contractual maturity dates of the debt securities in the nuclear decommissioning fund, by asset class at Sept. 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	$8,232	$105,016	$35,623	$19,927	$168,798
U.S. corporate bonds	345	42,949	114,639	18,517	176,450
Foreign securities	-	16,569	18,032	957	35,558
Municipal bonds	-	-	33,282	12,947	46,229
Asset-backed securities	-	5,836	4,410	-	10,246
Mortgage-backed securities	-	-	1,171	53,644	54,815
Debt securities	$8,577	$170,370	$207,157	$105,992	$492,096

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 Sept. 30, 2011, accumulated OCI related to interest rate derivatives included $0.8 million of net losses expected to be reclassified into earnings during the next 12 months as the related hedged interest rate transactions impact earnings.

At Sept. 30, 2011, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $450 million. These interest rate swaps were designated as hedges, and as such, changes in fair value are recorded to OCI. In addition, Xcel Energy entered into interest rate swaps with a notional amount of $175 million during the three months ended Sept. 30, 2011 which were settled in conjunction with the Xcel Energy Inc. debt issuance in September 2011. See Note 7 to the consolidated financial statements for further discussions of long-term borrowings.

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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 its electric and natural gas operations, as well as for trading purposes. This could include the purchase or sale of energy or energy-related products, natural gas to generate electric energy, gas for resale and vehicle fuel.

At Sept. 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 nine months ended Sept. 30, 2011 and Sept. 30, 2010.

At Sept. 30, 2011, accumulated OCI related to commodity derivative cash flow hedges included $0.1 million of net gains expected to be reclassified into earnings during the next 12 months as the hedged transactions occur.

Additionally, Xcel Energy enters into commodity derivative instruments for trading purposes not directly related to commodity price risks associated with serving its electric and natural gas customers. Changes in the fair value of these commodity derivatives are recorded in electric operating 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 Sept. 30, 2011 and Dec. 31, 2010:

(Amounts in Thousands) (a)(b)	Sept. 30, 2011	Dec. 31, 2010
Megawatt hours (MWh) of electricity	55,542	46,794
MMBtu of natural gas	72,002	75,806
Gallons of vehicle fuel	650	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 Sept. 30,	
(Thousands of Dollars)	2011	2010
Accumulated other comprehensive loss related to cash flow hedges at July 1	$ (7,582)	$ (9,590)
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges	(30,947)	35
After-tax net realized losses on derivative transactions reclassified into earnings	159	749
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$ (38,370)	$ (8,806)

	Nine Months Ended Sept. 30,	
(Thousands of Dollars)	2011	2010
Accumulated other comprehensive loss related to cash flow hedges at Jan. 1	$(8,094)	$(6,435)
After-tax net unrealized losses related to derivatives accounted for as hedges	(30,740)	(4,350)
After-tax net realized losses on derivative transactions reclassified into earnings	464	1,979
Accumulated other comprehensive loss related to cash flow hedges at Sept. 30	$(38,370)	$(8,806)

Xcel Energy had no derivative instruments designated as fair value hedges during the three and nine months ended Sept. 30, 2011 and Sept. 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 nine months ended Sept. 30, 2011 and Sept. 30, 2010, on OCI, regulatory assets and liabilities, and income:

Three Months Ended Sept. 30, 2011					
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains (Losses)
(Thousands of Dollars)	Other Comprehensive Loss	Regulatory Assets and Liabilities	Other Comprehensive Income (Loss)	Regulatory Assets and Liabilities	Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (51,033)	$ -	$ 354 (a)	$ -	$ -
Vehicle fuel and other commodity	(206)	-	(45)(e)	-	-
Total	$ (51,239)	$ -	$ 309	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 326 (b)
Electric commodity	-	10,392	-	(11,050)(c)	-
Natural gas commodity	-	(41,120)	-	308 (d)	(126)(b)
Total	$ -	$ (30,728)	$ -	$ (10,742)	$ 200

Nine Months Ended Sept. 30, 2011					
	Fair Value Changes Recognized During the Period in:		Pre-Tax Amounts Reclassified into Income During the Period from:		Pre-Tax Gains (Losses)
(Thousands of Dollars)	Other Comprehensive Income (Loss)	Regulatory Assets and Liabilities	Other Comprehensive Income (Loss)	Regulatory Assets and Liabilities	Recognized During the Period in Income
Derivatives designated as cash flow hedges					
Interest rate	$ (51,033)	$ -	$ 1,031 (a)	$ -	$ -
Vehicle fuel and other commodity	105	-	(129)(e)	-	-
Total	$ (50,928)	$ -	$ 902	$ -	$ -
Other derivative instruments					
Trading commodity	$ -	$ -	$ -	$ -	$ 7,096 (b)
Electric commodity	-	29,537	-	(28,605)(c)	-
Natural gas commodity	-	(58,299)	-	58,433 (d)	(126)(b)
Total	$ -	$ (28,762)	$ -	$ 29,828	$ 6,970

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	Three Months Ended Sept. 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 Income	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	$-	$-	$344	(a)	$-		$-
Vehicle fuel and other commodity	61	-	933	(e)	-		-
Total	$61	$-	$1,277		$-		$-
Other derivative instruments							
Trading commodity	$-	$-	$-		$-		$4,320 (b)
Electric commodity	-	6,568	-		(8,259)	(c)	-
Natural gas commodity	-	(65,303)	-		925	(d)	-
Total	$-	$(58,735)	$-		$(7,334)		$4,320

	Nine Months Ended Sept. 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)	$ -	$ 763	(a)	$ -		$ -
Vehicle fuel and other commodity	(261)	-	2,626	(e)	-		-
Total	$ (7,471)	$ -	$ 3,389		$ -		$ -
Other derivative instruments							
Trading commodity	$ -	$ -	$ -		$ -		$ 9,925 (b)
Electric commodity	-	(3,014)	-		(13,097)	(c)	-
Natural gas commodity	-	(106,009)	-		5,632	(d)	-
Other	-	-	-		-		135 (b)
Total	$ -	$ (109,023)	$ -		$ (7,465)		$ 10,060

(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 $6.9 million and $5.6 million of derivative instruments in a gross liability position at Sept. 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 $6.9 million and $9.8 million, respectively. At Sept. 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 Sept. 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 Sept. 30, 2011:

	Sept. 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	$-	$144	$-	$144	$ (65)	$79
Other derivative instruments:						
Trading commodity	129	25,653	31	25,813	(12,283)	13,530
Electric commodity	-	-	4,978	4,978	(1,653)	3,325
Total current derivative assets	$129	$25,797	$5,009	$30,935	$ (14,001)	16,934
Purchased power agreements (a)						33,347
Current derivative instruments						$50,281
Noncurrent derivative assets						
Derivatives designated as cash flow hedges:						
Vehicle fuel and other commodity	$-	$75	$-	$75	$ -	$75
Other derivative instruments:						
Trading commodity	-	32,919	-	32,919	(4,591)	28,328
Total noncurrent derivative assets	$-	$32,994	$-	$32,994	$ (4,591)	28,403
Purchased power agreements (a)						129,959
Noncurrent derivative instruments						$158,362

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	Sept. 30, 2011					
		Fair Value				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Fair Value Total	Counterparty Netting (b)	Total
Current derivative liabilities						
Derivatives designated as cash flow hedges:						
Interest rate	$-	$45,210	$-	$45,210	$ -	$45,210
Other derivative instruments:						
Trading commodity	135	20,759	37	20,931	(11,953)	8,978
Electric commodity	-	-	1,653	1,653	(1,653)	-
Natural gas commodity	793	49,524	-	50,317	(2,065)	48,252
Total current derivative liabilities	$928	$115,493	$1,690	$118,111	$ (15,671)	102,440
Purchased power agreements (a)						23,074
Current derivative instruments						$125,514
Noncurrent derivative liabilities						
Other derivative instruments:						
Trading commodity	$-	$15,813	$-	$15,813	$ (4,590)	$11,223
Total noncurrent derivative liabilities	$-	$15,813	$-	$15,813	$ (4,590)	11,223
Purchased power agreements (a)						254,258
Noncurrent derivative instruments						$265,481

(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 nine months ended Sept. 30, 2011. The following table presents the transfers that occurred between levels during the three and nine months ended Sept. 30, 2010.

	From Level 3 to Level 2 (a) (b)	
(Thousands of Dollars)	Three Months Ended	Nine Months Ended Sept. 30, 2010

	Sept. 30, 2010	
Trading commodity derivatives not designated as cash flow hedges:		
Current assets	$716	$ 7,271
Noncurrent assets	12,313	26,438
Current liabilities	(776)	(4,115)
Noncurrent liabilities	(9,269)	(16,069)
Total	$2,984	$ 13,525

(a) The transfer of amounts from Level 3 to Level 2 is due to the valuation of certain long-term derivative contracts for which observable commodity pricing forecasts became a more significant input during the period.

(b) There were no transfers of amounts from Level 2 to Level 3.

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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 nine months ended Sept. 30, 2011 and 2010:

	Three Months Ended Sept. 30	
(Thousands of Dollars)	2011	2010
Balance at July 1	$ 3,996	$ 9,806
Purchases	-	957
Settlements	(12)	(236)
Transfers out of Level 3	-	(2,984)
Losses recognized in earnings (a)	(7)	(2,622)

Gains recorded as regulatory assets and liabilities	10,392	6,691
Gains reclassified from regulatory assets and liabilities to earnings	(11,050)	(7,464)
Balance at Sept. 30	$ 3,319	$ 4,148

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(Thousands of Dollars)	Nine Months Ended Sept. 30, 2011	2010
Balance at Jan. 1	$ 2,392	$ 28,042
Purchases	-	(135)
Settlements	(72)	(303)
Transfers out of Level 3	-	(13,525)
Gains recognized in earnings (a)	64	6,180
Gains (losses) recorded as regulatory assets and liabilities	29,537	(3,220)
Gains reclassified from regulatory assets and liabilities to earnings	(28,602)	(12,891)
Balance at Sept. 30	$ 3,319	$ 4,148

(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:

	Sept. 30, 2011		Dec. 31, 2010	
(Thousands of Dollars)	Historical Cost	Fair Value	Historical Cost	Fair Value
Long-term debt, including current portion	$9,912,571	$11,687,247	$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 Sept. 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 Sept. 30, 2011 and Dec. 31, 2010, the historical cost of cash and cash equivalents, restricted cash, 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 Sept. 30,		Nine Months Ended Sept. 30,	
(Thousands of Dollars)	2011	2010	2011	2010
Interest income	$1,974	$4,880	$8,228	$8,174
COLI settlement	-	25,000	-	25,000
Other nonoperating income	806	-	2,590	1,105
Insurance policy expense	(159)	(2,362)	(2,245)	(4,110)
Other nonoperating expense	(71)	(68)	(278)	(35)
Other income, net	$2,550	$27,450	$8,295	$30,134

In July 2010, Xcel Energy Inc., PSCo and P.S.R. Investments, Inc. (PSRI) entered into a settlement agreement with Provident Life & Accident Insurance Company (Provident) related to all claims asserted by Xcel Energy Inc., PSCo and PSRI against Provident in a lawsuit associated with the discontinued COLI (Corporate Owned Life Insurance) program. Under the terms of the settlement, Xcel Energy Inc., PSCo and PSRI were paid $25 million by Provident and Reassure America Life Insurance Company. The $25 million proceeds are not subject to income taxes.

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10. Segment Information

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

Given the similarity of the regulated electric utility 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 $95.5 million and $97.6 million as of Sept. 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 utility and regulated natural gas utility segments the majority of costs are directly assigned to each segment. However, some costs, such as common depreciation, common O&M expenses and interest expense are allocated based on cost causation allocators. A general allocator is used for certain general and administrative expenses, including office supplies, rent, property insurance and general advertising.

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Three Months Ended Sept. 30, 2011					
Operating revenues from external customers	$2,619,424	$194,930	$17,244	$ -	$ 2,831,598
Intersegment revenues	294	294	-	(588)	-
Total revenues	$2,619,718	$195,224	$17,244	$ (588)	$ 2,831,598
Income (loss) from continuing operations	$353,846	$(6,445)	$(9,106)	$ -	$ 338,295

(Thousands of Dollars)	Regulated	Regulated	All	Reconciling	Consolidated

	Electric	Natural Gas	Other	Eliminations	Total
Three Months Ended Sept. 30, 2010					
Operating revenues from external customers	$2,440,917	$170,594	$17,276	$ -	$ 2,628,787
Intersegment revenues	268	4,258	-	(4,526)	-
Total revenues	$2,441,185	$174,852	$17,276	$ (4,526)	$ 2,628,787
Income (loss) from continuing operations	$303,301	$(5,167)	$14,354	$ -	$ 312,488

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(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2011					
Operating revenues from external customers	$6,777,793	$1,251,817	$56,750	$ -	$ 8,086,360
Intersegment revenues	989	1,690	-	(2,679)	-
Total revenues	$6,778,782	$1,253,507	$56,750	$ (2,679)	$ 8,086,360
Income (loss) from continuing operations	$670,965	$58,748	$(29,280)	$ -	$ 700,433

(Thousands of Dollars)	Regulated Electric	Regulated Natural Gas	All Other	Reconciling Eliminations	Consolidated Total
Nine Months Ended Sept. 30, 2010					
Operating revenues from external customers	$6,477,211	$1,210,154	$56,648	$ -	$ 7,744,013
Intersegment revenues	730	8,818	-	(9,548)	-
Total revenues	$6,477,941	$1,218,972	$56,648	$ (9,548)	$ 7,744,013
Income (loss) from continuing operations	$557,482	$68,102	$(10,131)	$ -	$ 615,453

11. Preferred and Common Stock

Preferred Stock — Xcel Energy Inc. has authorized 7,000,000 shares of preferred stock with a $100 par value. At Sept. 30, 2011 and Dec. 31, 2010, Xcel Energy Inc. had six series of preferred stock outstanding, redeemable at its option at prices ranging from $102.00 to $103.75 per share plus accrued dividends.

In September 2011, Xcel Energy Inc. announced it would redeem all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends. As such, the redemption premium of $3.3 million and accrued dividends are reflected as reductions of Xcel Energy's earnings available to common shareholders in the consolidated statements of income for the three and nine months ended Sept. 30, 2011.

Common Stock — In August 2010, Xcel Energy Inc. entered into equity forward agreements in connection with a public offering of 21.85 million shares of Xcel Energy Inc. common stock. Under the equity forward agreements (Forward Agreements), Xcel Energy Inc. agreed to issue to the banking counterparty 21.85 million shares of its common stock.

The equity forward instruments were accounted for as equity and recorded at fair value at the execution of the Forward Agreements, and were not subsequently adjusted for changes in fair value until settlement. Based upon the market terms of the equity forward instruments, including initial pricing of $20.855 per share determined based on the August 2010 offering price of Xcel Energy Inc.'s common stock of $21.50 per share less underwriting fees of $.0645 per share, and as no premium on the transaction was due either party to the Forward Agreements at execution, no fair value was recorded to equity for the instruments when the Forward Agreements were entered. The Forward Agreements settled on Nov. 29, 2010 and the proceeds of $449.8 million were recorded to common stock and additional paid in capital.

Common Stock Equivalents — At Sept. 30, 2011, 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 Sept. 30, 2011 and 2010, Xcel Energy Inc. had approximately 2.0 million and 5.2 million stock options outstanding, respectively, that were antidilutive, and therefore, excluded from the earnings per share calculation. For the nine months ended Sept. 30, 2011 and 2010, Xcel Energy Inc. had approximately 2.3 million and 6.1 million stock options outstanding, respectively, that were antidilutive, and therefore, excluded from the earnings per share calculation.

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Basic and Diluted Earnings Per Share Calculation

The dilutive impact of common stock equivalents affected earnings per share as follows for the three and nine months ended Sept. 30, 2011 and 2010:

	Three Months Ended Sept. 30, 2011			Three Months Ended Sept. 30, 2010		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$338,332			$312,306		
Less: Dividend requirements on preferred stock	(1,414)			(1,060)		
Less: Premium on redemption of preferred stock	(3,260)			-		
Basic earnings per share:						
Earnings available to common shareholders	333,658	485,344	$0.69	311,246	460,471	$0.68
Effect of dilutive securities:						
401(k) equity awards	-	550		-	581	
Equity forward instruments	-	-		-	967	
Diluted earnings per share:						
Earnings available to common shareholders	$333,658	485,894	$0.69	$311,246	462,019	$0.67

	Nine Months Ended Sept. 30, 2011			Nine Months Ended Sept. 30, 2010		
(Amounts in thousands, except per share data)	Income	Shares	Per Share Amount	Income	Shares	Per Share Amount
Net income	$700,663			$619,200		
Less: Dividend requirements on preferred stock	(3,534)			(3,180)		
Less: Premium on redemption of preferred stock	(3,260)			-		
Basic earnings per share:						
Earnings available to common shareholders	693,869	484,640	$1.43	616,020	459,816	$1.34
Effect of dilutive securities:						
401(k) equity awards	-	512		-	583	
Equity forward instruments	-	-		-	323	
Diluted earnings per share:						
Earnings available to common shareholders	$693,869	485,152	$1.43	$616,020	460,722	$1.34

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12. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

	Three Months Ended Sept. 30,			
	2011	2010	2011	2010
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$19,330	$18,286	$1,206	$1,002
Interest cost	40,353	41,253	10,522	10,695
Expected return on plan assets	(55,400)	(58,080)	(7,991)	(7,132)
Amortization of transition obligation	-	-	3,611	3,611
Amortization of prior service cost (credit)	5,633	5,165	(1,233)	(1,233)
Amortization of net loss	19,627	12,078	3,324	2,910
Net periodic benefit cost	29,543	18,702	9,439	9,853
Costs not recognized and additional cost recognized due to the effects of regulation	(9,299)	(6,630)	972	972
Net benefit cost recognized for financial reporting	$20,244	$12,072	$10,411	$10,825

	Nine Months Ended Sept. 30,			
	2011	2010	2011	2010
(Thousands of Dollars)	Pension Benefits		Postretirement Health Care Benefits	
Service cost	$57,990	$54,860	$3,618	$3,005
Interest cost	121,059	123,758	31,565	32,085
Expected return on plan assets	(166,200)	(174,239)	(23,972)	(21,397)
Amortization of transition obligation	-	-	10,833	10,833
Amortization of prior service cost (credit)	16,899	15,493	(3,699)	(3,699)
Amortization of net loss	58,883	36,236	9,971	8,732
Net periodic benefit cost	88,631	56,108	28,316	29,559
Costs not recognized and additional cost recognized due to the effects of regulation	(27,899)	(20,270)	2,918	2,918
Net benefit cost recognized for financial reporting	$60,732	$35,838	$31,234	$32,477

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 New Century Energies, Inc. (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. Xcel Energy does not expect additional pension contributions during 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 Sept. 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 and provide details of earnings results. We believe that this measurement is useful to investors to evaluate the actual and projected financial performance and contribution of our subsidiaries. This non-GAAP financial measure should not be considered as an alternative to 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 Sept. 30,		Nine Months Ended Sept. 30,	
Diluted Earnings (Loss) Per Share	2011	2010	2011	2010
PSCo	$0.29	$0.29	$0.63	$0.69
NSP-Minnesota	0.29	0.24	0.62	0.48
SPS	0.10	0.08	0.17	0.16
NSP-Wisconsin	0.04	0.04	0.09	0.08
Equity earnings of unconsolidated subsidiaries	0.01	0.01	0.03	0.03
Regulated utility — continuing operations	0.73	0.66	1.54	1.44
Xcel Energy Inc and other costs	(0.04)	(0.04)	(0.11)	(0.10)
Ongoing diluted earnings per share	0.69	0.62	1.43	1.34
COLI settlement and Medicare Part D	-	0.05	-	(0.01)
Earnings per share from continuing operations	0.69	0.67	1.43	1.33
Earnings per share from discontinued operations	-	-	-	0.01
GAAP diluted earnings per share	$0.69	$0.67	$1.43	$1.34

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

Adjustments to GAAP Earnings

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.

In July 2010, Xcel Energy Inc. PSCo and PSRI entered into a settlement agreement with Provident Life & Accident Insurance Company (Provident) related to all claims asserted by Xcel Energy Inc., PSCo and PSRI against Provident in a lawsuit associated with the discontinued COLI program. Under the terms of the settlement, Xcel Energy Inc., PSCo and PSRI were paid $25 million by Provident and Reassure America Life Insurance Company resulting in approximately $0.05 of nonrecurring earnings per share in the third quarter of 2010. The $25 million proceeds are not subject to income taxes.

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 $0.07 per share for the third quarter and $0.09 per share for the nine months ended Sept. 30, 2011.

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PSCo — PSCo earnings were flat for the third quarter and decreased $0.06 per share for the nine months ended Sept. 30, 2011. For the third quarter, higher electric margins, driven by warmer weather in July and August 2011, were offset by higher O&M expenses, depreciation expense and property taxes. Year to date earnings decreased due to the implementation of seasonal rates in June 2010 (seasonal rates are higher in the summer months and lower throughout the other months of the year), higher O&M expenses, depreciation expense and property taxes.

NSP-Minnesota — NSP-Minnesota earnings increased $0.05 per share for the third quarter and $0.14 per share for the nine months ended Sept. 30, 2011. The increases are primarily due to interim rates, subject to refund, in Minnesota and North Dakota and conservation improvement program incentives. These factors were partially offset by higher O&M expenses, depreciation expense and property taxes.

SPS — SPS earnings increased $0.02 per share for the third quarter and $0.01 per share for the nine months ended Sept. 30, 2011. Higher electric revenues, primarily due to the Texas retail rate increase, as well as warmer weather were partially offset by higher O&M expenses, depreciation expense and property taxes.

NSP-Wisconsin — NSP-Wisconsin earnings were flat for the third quarter and increased $0.01 per share for the nine months ended Sept. 30, 2011. The implementation of new electric rates were partially offset by higher O&M expenses and depreciation expense.

Changes in Diluted Earnings Per Share

The following table summarizes 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 Sept. 30,	Nine Months Ended Sept. 30,
2010 GAAP diluted earnings per share	$0.67	$1.34
Earnings per share from discontinued operations	-	(0.01)
2010 diluted earnings per share from continuing operations	0.67	1.33
COLI settlement and Medicare Part D	(0.05)	0.01
2010 ongoing diluted earnings per share	0.62	1.34
Components of change — 2011 vs 2010		
Higher electric margins	0.18	0.42
Higher natural gas margins	0.01	0.03
Dilution from DSPP, benefit plans and the 2010 common equity issuance	(0.04)	(0.08)
Higher operating and maintenance expenses	(0.03)	(0.09)
Higher depreciation and amortization	(0.03)	(0.08)
Higher conservation and DSM expenses (generally offset in revenues)	(0.01)	(0.05)
Higher taxes (other than income taxes)	(0.01)	(0.04)
Other, net (including interest and premium on redemption of preferred stock)	-	(0.02)
2011 GAAP and ongoing diluted earnings per share	$0.69	$1.43

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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 Sept. 30, 2011	Three Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2011	Nine Months Ended Sept. 30, 2010
GAAP income (loss) by segment				
Regulated electric income	$353.8	$303.3	$671.0	$557.5
Regulated natural gas income	(6.4)	(5.2)	58.7	68.1
Other income (a)	8.4	31.0	18.1	30.6
Segment income — continuing operations	355.8	329.1	747.8	656.2
Xcel Energy Inc. and other costs (a)	(17.5)	(16.6)	(47.3)	(40.7)
Total income — continuing operations	338.3	312.5	700.5	615.5
Income (loss) from discontinued operations	-	(0.2)	0.2	3.7
Total GAAP net income	$338.3	$312.3	$700.7	$619.2

Contributions to Diluted Earnings (Loss) Per Share	Three Months Ended Sept. 30, 2011	Three Months Ended Sept. 30, 2010	Nine Months Ended Sept. 30, 2011	Nine Months Ended Sept. 30, 2010
GAAP earnings (loss) by segment				
Regulated electric	$0.73	$0.66	$1.38	$1.21
Regulated natural gas	(0.01)	(0.01)	0.12	0.15
Other (a)	0.01	0.06	0.04	0.07
Segment earnings per share — continuing operations	0.73	0.71	1.54	1.43
Xcel Energy Inc. and other costs(a)	(0.04)	(0.04)	(0.11)	(0.10)
Total earnings per share — continuing operations	0.69	0.67	1.43	1.33
Discontinued operations	-	-	-	0.01
Total GAAP earnings per share — diluted	$0.69	$0.67	$1.43	$1.34

(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.

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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 Sept. 30,			Nine Months Ended Sept. 30,		
	2011 vs. Normal	2010 vs. Normal (a)	2011 vs. 2010	2011 vs. Normal	2010 vs. Normal (a)	2011 vs. 2010
HDD	(11.9)%	(30.2)%	26.2 %	3.8 %	(3.3)%	7.4 %
CDD	38.6	10.1	25.8	37.3	12.3	22.2
THI	50.3	38.8	8.3	36.0	30.5	4.3

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

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 Sept. 30,			Nine Months Ended Sept. 30,		
	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010	2011 vs. Normal	2010 vs. Normal	2011 vs. 2010
Retail electric	$0.07	$0.04	$0.03	$0.08	$0.05	$0.03
Firm natural gas	0.00	0.00	0.00	0.00	(0.01)	0.01
Total	$0.07	$0.04	$0.03	$0.08	$0.04	$0.04

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 Sept. 30,			
	Actual	Weather Normalized	Actual Lubbock (a)	Weather Normalized Lubbock (a)
Electric residential	2.7 %	(0.7) %	3.8 %	0.3 %
Electric commercial and industrial	1.1	0.1	2.1	1.0
Total retail electric sales	1.7	(0.1)	2.7	0.9
Firm natural gas sales	(1.4)	(4.3)	N/A	N/A

	Nine Months Ended Sept. 30,			
	Actual	Weather Normalized	Actual Lubbock (a)	Weather Normalized Lubbock (a)
Electric residential	0.8 %	(0.6) %	1.8 %	0.3 %
Electric commercial and industrial	0.6	0.2	1.5	1.1
Total retail electric sales	0.7	0.0	1.7	1.0
Firm natural gas sales	1.2	(3.0)	N/A	N/A

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

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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 Sept. 30,		Nine Months Ended Sept. 30,	
(Millions of Dollars)	2011	2010	2011	2010
Electric revenues	$ 2,619	$ 2,441	$ 6,778	$ 6,477
Electric fuel and purchased power	(1,150)	(1,111)	(3,071)	(3,085)
Electric margin	$ 1,469	$ 1,330	$ 3,707	$ 3,392

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

Electric Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2011 vs. 2010	Nine Months Ended Sept. 30, 2011 vs. 2010
Fuel and purchased power cost recovery	$65	$7
Retail rate increases, including seasonal rates (Minnesota interim, Wisconsin, Texas, North Dakota interim, Michigan and Colorado)	41	97
Revenue requirements for PSCo gas generation acquisition (a)	29	98
Estimated impact of weather	19	20
Transmission revenue	15	39
Conservation and DSM revenue (offset by expenses)	10	27
Conservation and DSM incentive	8	16
Firm wholesale	7	8
Trading, including PSCo renewable energy credit sales	(12)	(8)
Non-fuel riders	(3)	8
Other, net	(1)	(11)
Total increase in electric revenues	$178	$301

Electric Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2011 vs. 2010	Nine Months Ended Sept. 30, 2011 vs. 2010
Retail rate increases, including seasonal rates (Minnesota interim, Wisconsin, Texas, North Dakota interim, Michigan and Colorado)	$41	$97
Revenue requirements for PSCo gas generation acquisition (a)	29	98
Estimated impact of weather	19	20
Conservation and DSM revenue (offset by expenses)	10	27
Firm wholesale	9	13

Conservation and DSM incentive	8	16
Transmission revenue, net of costs	5	15
Non-fuel riders	(3)	8
Other, net (including trading and deferred fuel adjustments)	21	21
Total increase in electric margin	$139	$315

(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 higher O&M expense, depreciation expense, property taxes and financing costs.

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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 table details natural gas revenues and margin:

	Three Months Ended Sept. 30,		Nine Months Ended Sept. 30,	
(Millions of Dollars)	2011	2010	2011	2010
Natural gas revenues	$195	$171	$1,252	$1,210
Cost of natural gas sold and transported	(87)	(67)	(794)	(775)
Natural gas margin	$108	$104	$458	$435

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

Natural Gas Revenues

(Millions of Dollars)	Three Months Ended Sept. 30, 2011 vs. 2010	Nine Months Ended Sept. 30, 2011 vs. 2010
Purchased natural gas adjustment clause recovery	$21	$20
Conservation and DSM revenue (offset by expenses)	1	12
Retail sales decrease (excluding weather impact)	(1)	(4)
Estimated impact of weather	-	9
Conservation and DSM incentive	-	1
Other, net	3	4
Total increase in natural gas revenues	$24	$42

Natural Gas Margin

(Millions of Dollars)	Three Months Ended Sept. 30, 2011 vs. 2010	Nine Months Ended Sept. 30, 2011 vs. 2010
Conservation and DSM revenue (offset by expenses)	$1	$12
Retail sales decrease (excluding weather impact)	(1)	(4)
Estimated impact of weather	-	9
Conservation and DSM incentive	-	1
Other, net	4	5
Total increase in natural gas margin	$4	$23

Non-Fuel Operating Expenses and Other Items

O&M Expenses — O&M expenses increased $23.3 million, or 4.6 percent, for the third quarter and $67.9 million, or 4.5 percent for the nine months ended Sept. 30, 2011 compared with the same periods in 2010. The following table summarizes the changes in O&M expenses:

(Millions of Dollars)	Three Months Ended Sept. 30, 2011 vs. 2010	Nine Months Ended Sept. 30, 2011 vs. 2010
Higher plant generation costs	$6	$23
Higher labor and contract labor costs	4	18
Higher employee benefit expense	3	9
Higher facilities expense	3	3
Higher nuclear plant operation costs	3	2
Other, net	4	13
Total increase in O&M expenses	$23	$68

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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 and the impact of annual wage increases.
- Higher employee benefit costs for the nine month comparable periods are primarily due to higher pension expense.
- Higher nuclear plant operation costs were largely driven by increased labor and contractors for security-related requirements.

Conservation and DSM Program Expenses — Conservation and demand side management (DSM) program expenses increased $10.4 million, or 17.1 percent for the third quarter and $37.6 million, or 21.6 percent for the nine months ended Sept. 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.

Depreciation and Amortization — Depreciation and amortization expense increased $20.7 million, or 9.3 percent for the third quarter and $57.0 million, or 8.9 percent for the nine months ended Sept. 30, 2011, compared with the same periods in 2010. The year to date 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 $7.2 million, or 8.8 percent for the third quarter and $33.9 million, or 13.9 percent for the nine months ended Sept. 30, 2011, compared with the same periods in 2010. The increase is primarily due to an increase in property taxes in Colorado and Minnesota.

Other Income, Net — Other income, net decreased $24.9 million for the third quarter and $21.8 million for the nine months ended Sept. 30, 2011, compared with the same periods in 2010. The decrease is primarily due to the COLI settlement in July 2010.

Allowance for Funds Used During Construction, Equity and Debt (AFUDC) — AFUDC decreased $1.6 million, or 8.3 percent for the third quarter and was flat for the nine months ended Sept. 30, 2011, compared with the same periods in 2010. The change is primarily due to lower AFUDC rates, partially offset by higher average construction work in progress (CWIP) due to major construction projects, including the Monticello extended power uprate and Jones Unit 3 and Unit 4, as well as SPS' transmission projects.

Interest Charges — Interest charges increased $3.2 million, or 2.2 percent for the third quarter and $8.6 million, or 2.0 percent for the nine months ended Sept. 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 $27.1 million for the third 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. The effective tax rate for continuing operations was 36.4 percent for the third quarter of 2011 compared with 34.7 percent for the same period in 2010. The higher effective tax rate for 2011 was primarily due to the establishment of a partial valuation allowance against certain state tax credit carryovers that are expected to expire. Without this adjustment, the effective tax rate for continuing operations for the third quarter of 2011 would have been 35.6 percent.

Income tax expense for continuing operations increased $24.9 million for the nine months ended Sept. 30, 2011, compared with the same period in 2010. The increase in income tax expense was primarily due to an increase in pretax income, the establishment of a partial valuation allowance in 2011 against certain state tax credit carryovers that are expected to expire, and a reversal of a valuation allowance for certain state tax credit carryovers in 2010. These were partially offset by 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. The effective tax rate for continuing operations was 35.8 percent for the nine months ended Sept. 30, 2011 compared with 37.2 percent for the same period in 2010. The higher effective tax rate for 2010 was primarily due to the Medicare Part D, COLI, and 2010 valuation allowance. Without these adjustments, the effective tax rate for continuing operations for the first nine months of 2010 would have been 35.3 percent.

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Premium on Redemption of Preferred Stock — In September 2011, Xcel Energy announced it would redeem all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends. As such, the redemption premium of $3.3 million and accrued dividends are reflected as reductions to earnings available to common shareholders for the three and nine months ended Sept. 30, 2011.

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.

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 RES rider. NSP-Minnesota has 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. On Sept. 16, 2011, the U.S. District Court denied the motion to dismiss. The trial is set to begin in late 2012 or early 2013.

NSP-Minnesota Transmission Certificate of Need (CON) — 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.

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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, N.D. to St. Cloud, Minn. project and the Minnesota portion of the Brookings, S.D. to Hampton, Minn. project. The SDPUC granted the facility permit for the South Dakota portion of the Brookings, S.D. 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 for the remainder of the portfolio by the end of 2011.

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. 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. An MPUC decision on the CON and route permit is expected by early 2012.

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. An MPUC decision regarding both applications is expected 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 a 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.

The proposed 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.

In October 2011, NSP-Minnesota requested to suspend the CON process to reevaluate the timing of the Black Dog Repowering project as part of a comprehensive review to update the NSP-Minnesota resource plan.

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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 of Xcel Energy Inc.'s 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.

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 NRC adopts 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 Plant Extended Power Uprate — In 2008, NSP-Minnesota filed for both state and federal approvals of an extended power uprate of approximately 71 MW for NSP-Minnesota's Monticello nuclear plant. The MPUC approved the CON for the extended power uprate in 2008. The filing was placed on hold by the NRC staff to address concerns raised by the Advisory Committee on Reactor Safeguards related to containment pressure associated with pump performance. NSP-Minnesota has been working with the industry and regulatory agencies to address this issue and had expected to receive a regulatory decision on the license application in 2012. In October 2011, the Advisory Committee issued additional recommendations to suspend the use of containment accident pressure credit in all new licenses until the causes and risks of Japan's Fukushima incident are better understood. NSP-Minnesota is evaluating the impact of this recommendation on the timing of the license decision which will likely result in a delay of the approval. NSP-Minnesota is considering implementing the equipment changes needed to support the Monticello life extension and power uprate projects in the planned spring 2013 refueling outage.

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. Analysis of recent extended power uprate submittals to the NRC concluded that significant additional design work beyond current schedule and cost plan estimates are now being required to submit a successful application. As a result, NSP Minnesota is completing an economic and new project design analysis to determine project impacts.

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. NSP-Wisconsin has provided updated information regarding the project regional transmission needs. The PSCW Staff is currently developing the draft Environmental Impact Statement. A decision is expected in mid-2012.

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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.

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. During the second quarter of 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 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 Generating Station in 2014;
- Install SCRs 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.

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The CPUC provided for recovery on 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 further discussion. In April 2011, the Colorado General Assembly approved legislation authorizing the regional haze SIP which includes the CACJA plan. Upon signature by the Governor of Colorado, the SIP 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.

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. In the third quarter of 2011, the Administrative Law Judge (ALJ) approved the CPCN, which has now become the final affirmative decision of the CPUC.

In April 2011, PSCo filed for approval of the decommissioning of Cherokee 1 and 2 to provide space for the new combined-cycle plant. Hearings were held in August 2011 and the ALJ issued a decision recommending approval of the CPCN. Parties have asked the CPUC to consider changes to some aspects of the CPCN before approval. A final decision is expected in the fourth quarter of 2011.

In the third quarter of 2011, PSCo filed separate CPCNs for the emissions controls and the natural gas combined-cycle unit at the Pawnee Generating Station. Hearing dates for these matters are scheduled for October and December 2011, respectively, with decisions expected in the fourth quarter of 2011 and first quarter of 2012, respectively.

In October 2011, PSCo filed for approval of the Hayden emissions controls. There has been no procedural schedule set at this time.

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. The Cameo Generating 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 began during the summer of 2011 and should be completed by the fall of 2012.

San Luis Valley-Calumet-Comanche 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, due to delays in the siting and permitting of the line, the in-service date has been delayed. 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 approved the CPCN in September 2011. A landowner opposing the project appealed the CPUC decision.

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. 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.

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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 on Nov. 1, 2011, 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.

SPS

New Mexico GHG Regulations — In 2010, the New Mexico Environmental Improvement Board (EIB) adopted two regulations to limit GHG emissions, including CO2 emissions from power plants and other industrial sources. SPS, other utilities and industry groups have filed separate appeals with the New Mexico Court of Appeals challenging the validity of these two GHG regulations. The appellate cases have been stayed pending further proceedings before the EIB. In July 2011, SPS and other parties filed a petition for repeal of each state GHG rule, and the EIB set both petitions for hearing by the end of 2011. The rules are scheduled to become applicable to SPS beginning in 2013.

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 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 audit reports have been issued and referred to MRO's enforcement function for further action. 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.

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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 responded to in September 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 and 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.

Pacific Northwest FERC Refund Proceeding — In July 2001, the FERC ordered a preliminary hearing to determine whether there may have been unjust and unreasonable charges for spot market bilateral sales in the Pacific Northwest for December 2000 through June 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been a participant in the hearings. In September 2001, the presiding ALJ concluded that prices in the Pacific Northwest during the referenced period were the result of a number of factors, including the shortage of supply, excess demand, drought and increased natural gas prices. Under these circumstances, the ALJ concluded that the prices in the Pacific Northwest markets were not unreasonable or unjust and no refunds should be ordered. Subsequent to the ruling, the FERC has allowed the parties to request additional evidence. Parties have claimed that the total amount of transactions with PSCo subject to refund is $34 million. In June 2003, the FERC issued an order terminating the proceeding without ordering further proceedings. Certain purchasers filed appeals of the FERC's orders in this proceeding with the U.S. Court of Appeals for the Ninth Circuit.

In an order issued in August 2007, the Court of Appeals remanded the proceeding back to the FERC. The Court of Appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The Court of Appeals denied a petition for rehearing in April 2009, and the mandate was issued.

In October 2011, the FERC issued an order on remand for a hearing with an ALJ and with settlement judge procedures. The FERC requested the ALJ to assess possible unlawful market activity affecting bilateral contracts and to determine an applicable refund methodology.

FERC Order 1000, Transmission Planning and Cost Allocation (Order 1000) — In July 2011, the FERC issued Order 1000 adopting new requirements for transmission planning, cost allocation, and development. Order 1000 will require significant changes in transmission planning and cost allocation mechanisms in the Western Interconnection where PSCo is located. The impacts of the provisions of Order 1000 regarding transmission planning and cost allocation on SPS and the NSP System are expected to be less significant as they already participate in regional planning and cost allocation processes. The impacts of the new requirements of Order 1000 relating to future transmission develop and ownership on the company are uncertain. Compliance filings to address these new requirements are due October 2012 and are effective prospectively. In August 2011, motions for rehearing were filed and are pending action by the

FERC.

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 Sept. 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 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 Sept. 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:

	Nine Months Ended Sept. 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	(9,064)	(4,282)
Commodity trading contract additions and changes during period	10,803	14,494
Fair value of commodity trading net contract assets outstanding at Sept. 30	$21,988	$19,840

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At Sept. 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	$4,469	$16,007	$153	$-	$20,629
PSCo	1	414	945	-	-	1,359
		$4,883	$16,952	$153	$-	$21,988

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

At Sept. 30, 2011, a 10 percent increase in market prices for commodity trading contracts would increase pretax income from continuing operations by approximately $0.5 million, whereas a 10 percent decrease would decrease pretax income from continuing operations by approximately $0.5 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:

(Millions of Dollars)	Period Ended Sept. 30,	VaR Limit	Average	High	Low
2011	$ 0.17	$ 3.00	$ 0.12	$ 0.32	$ 0.04
2010	0.43	3.00	0.25	0.64	0.06

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 Sept. 30, 2011, Xcel Energy had unsettled interest rate swaps outstanding with a notional amount of $450 million.

At Sept. 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 $1.2 million annually, or approximately $0.3 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 Sept. 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.

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 Sept. 30, 2011, a 10 percent increase in prices would have resulted in an increase in credit exposure of $121.1 million, while a decrease of 10 percent would have resulted in a decrease in credit exposure of $43.8 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.

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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 Sept. 30, 2011. Adjustments to fair value for credit risk of commodity trading instruments are recorded in electric revenues when necessary. Credit risk adjustments for non-trading 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 Sept. 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 Sept. 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 $5.0 million and $1.7 million, respectively, of estimated fair values for FTRs held at Sept. 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 delivery 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 Sept. 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 $65.1 million in the nuclear decommissioning fund at Sept. 30, 2011 (approximately 4.9 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

(Millions of Dollars)	Nine Months Ended Sept. 30, 2011	Nine Months Ended Sept. 30, 2010
Cash provided by operating activities	$1,924	$1,526

Cash provided by operating activities increased by $398 million for the first nine months ended Sept. 30, 2011, compared with the nine months ended Sept. 30, 2010. The increase was a result of changes in working capital, primarily due to changes in accounts payable and accounts receivable related to the timing of payments and receipts, as well as changes in regulatory assets and liabilities due mainly to the nuclear waste disposal settlement of $100 million, 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.

(Millions of Dollars)	Nine Months Ended Sept. 30, 2011	Nine Months Ended Sept. 30, 2010
Cash used in investing activities	$(1,661)	$(1,521)

Cash used in investing activities increased by $140 million for the first nine months ended Sept. 30, 2011, compared with the nine months ended Sept. 30, 2010. This increase was due to the receipt of the nuclear waste disposal settlement of $100 million recorded to restricted cash during 2011, as well as higher capital expenditures, primarily at NSP-Minnesota for the Monticello extended power uprate and CapX2020 projects, at PSCO for the transmission line projects, and at SPS for the Jones Unit 3 and Unit 4, as well as SPS' transmission projects.

(Millions of Dollars)	Nine Months Ended Sept. 30, 2011	Nine Months Ended Sept. 30, 2010
Cash (used in) provided by financing activities	$(177)	$103

Cash used in financing activities increased by $280 million for the first nine months ended Sept. 30, 2011, compared with the nine months ended Sept. 30, 2010. The increase is primarily due to higher proceeds from the issuance of long-term debt in 2010, partially offset by higher dividend payments and the repayment of long term debt in 2011, including $57.3 million of SPS' pollution control revenue bonds.

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.

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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, the year-end discount rate, IRS and legislative initiatives as well as other actuarial assumptions, are estimated to range between $150 million to $200 million.

Premium on Redemption of Preferred Stock — In September 2011, Xcel Energy announced it would redeem all series of its preferred stock on Oct. 31, 2011, at an aggregate purchase price of $108 million, plus accrued dividends. As such, the redemption premium of $3.3 million and accrued dividends are reflected as reductions to earnings available to common shareholders for the three and nine months ended Sept. 30, 2011.

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 Sept. 30, 2011, approximately $121.5 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 Sept. 30, 2011	Twelve Months Ended Dec. 31, 2010
Borrowing limit	$ 2,450	$ 2,177
Amount outstanding at period end	50	466
Average amount outstanding	477	263
Maximum amount outstanding	824	653
Weighted average interest rate, computed on a daily basis	0.36 %	0.36 %
Weighted average interest rate at period end	0.34	0.40

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Credit Facilities — During March of 2011, NSP-Minnesota, NSP-Wisconsin, PSCo, SPS and Xcel Energy Inc. executed new four-year credit agreements. The total capacity of the credit facilities increased approximately $273 million to $2.45 billion. As of Oct. 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	$ 29.1	$ 770.9	$ 0.2	$ 771.1
PSCo	700.0	4.8	695.2	23.7	718.9
NSP-Minnesota	500.0	7.1	492.9	0.2	493.1
SPS	300.0	-	300.0	30.5	330.5
NSP-Wisconsin	150.0	45.0	105.0	0.6	105.6
Total	$ 2,450.0	$ 86.0	$ 2,364.0	$ 55.2	$ 2,419.2

(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 between the utility subsidiaries. Xcel Energy Inc. may make investments in the utility subsidiaries at market-based interest rates; however, the money pool arrangement does not allow the utility subsidiaries to make investments in Xcel Energy Inc. The money pool balances are eliminated during consolidation.

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

Financing Plans — Xcel Energy issues debt and equity securities to refinance retiring maturities, reduce short-term debt, fund construction programs, infuse equity in subsidiaries, fund asset acquisitions and for other general corporate purposes. During the third quarter, Xcel Energy Inc. and its utility subsidiaries completed the following financing:

- In August 2011, PSCo issued $250 million of 30-year first mortgage bonds with a coupon of 4.75 percent.
- In August 2011, SPS issued $200 million of 30-year first mortgage bonds with a coupon of 4.5 percent.
- In September 2011, Xcel Energy Holding Co. issued $250 million of 30-year unsecured bonds with a coupon of 4.8 percent.
- In September 2011, Xcel Energy Holding Co. announced it would redeem all series of its preferred stock on Oct. 31, 2011. The preferred stock has a par value of $105 million.

Xcel Energy Holding Co. and its utility subsidiaries' financing plans are largely completed for 2011 with the exception of the periodic issuance and repayment of short-term debt and the expected issuance of equity through the Dividend Reinvestment and Stock Purchase Plan (DSPP) and various benefit programs, which is expected to result in the issuance of $75 million throughout 2011. Xcel Energy plans to refinance the current portion of long-term debt coming due in 2012.

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

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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. Xcel Energy expects 2011 ongoing earnings to be in the upper half of the guidance range. Key assumptions related to ongoing earnings are detailed below:

- Normal weather patterns are experienced for the remainder of the year.
- Weather-adjusted retail electric utility sales, adjusted for the sale of the Lubbock distribution assets, are projected to grow approximately 1 percent.
- Weather-adjusted retail firm natural gas sales are projected to decline approximately 3 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 approximately 4.5 percent.
- Depreciation expense is projected to increase approximately $60 million to $70 million.
- Interest expense (net of AFUDC — debt) is projected to increase approximately $10 million to $15 million.
- AFUDC — equity is projected to be relatively flat.
- The effective tax rate is projected to be approximately 35 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 486 million shares.

Xcel Energy's 2012 ongoing earnings guidance is $1.75 to $1.85 per share. Key assumptions related to ongoing earnings are detailed below:

- Constructive outcomes in all rate case and regulatory proceedings.
- Normal weather patterns are experienced for the year.
- Weather-adjusted retail electric utility sales are projected to grow 0.5 to 1.0 percent.
- Weather-adjusted retail firm natural gas sales are projected to grow up to 1.0 percent.
- Rider revenue recovery is projected to increase approximately $50 million to $55 million over 2011 projected levels.
- O&M expenses are projected to increase approximately 3.0 to 4.0 percent over 2011 projected levels.
- Depreciation expense is projected to increase $70 million to $80 million over 2011 projected levels.
- Interest expense (net of AFUDC — debt) is projected to be relatively flat.
- AFUDC — equity is projected to increase approximately $25 million to $30 million over 2011 projected levels.
- The effective tax rate is projected to be approximately 34 percent to 36 percent.
- Average common stock and equivalents are projected to be approximately 488 million shares.

Item 3 — QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis under Item 2.

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Item 4 — CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Xcel Energy maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed in 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 Sept. 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 Rate 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.

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.

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If an incident did occur, it could have a material 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, although the EPA announced in late September that this proposed rule will be delayed.

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.

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 effect on our results of operations.

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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 5 — Other Information

On Oct. 25, 2011, as a result of Teresa Madden assuming the position of Senior Vice President and Chief Financial Officer and Jeffrey Savage assuming the position of Vice President and Controller, the Governance, Compensation and Nominating Committee of the Xcel Energy Inc.'s Board of Directors took action to name Ms. Madden a Tier 1 Participant under Xcel Energy Inc.'s Senior Executive Severance and Change in Control Policy and to name Mr. Savage a participant in the Xcel Energy Inc.'s Business Unit Vice President Severance Plan, effective Nov. 1, 2011. As a result, if Ms. Madden is terminated, including a voluntary termination following a diminution in salary, benefits or responsibilities within two years following a change in control of Xcel Energy Inc., she will be eligible to receive the benefits outlined under "Potential Payments Upon Termination or Change in Control" on page 76 of Xcel Energy Inc.'s Definitive Proxy Statement on Schedule 14A (File no. 001-03034), filed with the Commission on April 5, 2011. As a Tier 1 Participant, Ms. Madden's severance multiplier will be three times; however, Ms. Madden will not be entitled to receive the additional cash payment for any excise tax on excess parachute payments in the event of a change in control. If Mr. Savage is terminated, including a voluntary termination following a material diminution in salary or as a result of a material change in the geographic location at which Mr. Savage must perform his services, Mr. Savage will be entitled to receive similar benefits, except his severance multiplier will be one times and Mr. Savage will be entitled to receive a cash payment of fifteen thousand dollars in lieu of outplacement services.

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)).
4.01*	Supplemental Indenture No. 6 dated as of Sept. 1, 2011 between Xcel Energy Inc. and Wells Fargo Bank, National Association (NA), as Trustee, creating $250 million principal amount of 4.80 percent Senior Notes, Series due 2041. (Exhibit 4.01 to Form 8-K dated Sept. 12, 2011 (file no. 001-03034)).
4.02*	Supplemental Indenture dated as of Aug. 1, 2011 between PSCo and U.S. Bank NA, as successor Trustee, creating $250 million principal amount of 4.75 percent First Mortgage Bonds, Series No. 22 due 2041. (Exhibit 4.01 to Form 8-K dated Aug. 9, 2011 (file no. 001-03280)).
4.03*	Indenture dated as of Aug. 1, 2011 between SPS and U.S. Bank NA, as Trustee. (Exhibit 4.01 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
4.04*	Supplemental Indenture dated as of Aug. 3, 2011 between SPS and U.S. Bank NA, as Trustee, creating $200 million principal amount of 4.50 percent First Mortgage Bonds, Series No. 1 due 2041. (Exhibit 4.02 to Form 8-K dated Aug. 10, 2011 (file no. 001-03789)).
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 Sept. 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.
Oct. 28, 2011	By:	/s/ JEFFREY S. SAVAGE Jeffrey S. Savage Vice President and Controller (Principal Accounting Officer)
		/s/ TERESA S. MADDEN Teresa S. Madden Senior Vice President and Chief Financial Officer (Principal Financial Officer)