XCEL ENERGY INC
Form 10-Q
August 01, 2008
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2008

OR

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

For the transition period from to

Commission File Number: 1-3034

Xcel Energy Inc.

(Exact name of registrant as specified in its charter)

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

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

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. x Yes o No

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 definitions of large accelerated filer, accelerated filer, and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one): x Large accelerated filer o Accelerated filer o Non-accelerated filer (Do not check if a smaller reporting company) o Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
o Yes x No

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

Class	**Outstanding at July 31, 2008**
Common Stock, $2.50 par value	431,004,383 shares

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

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PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(Thousands of Dollars, Except Per Share Data)	Three Months Ended June 30, 2008	2007	Six Months Ended June 30, 2008	2007
Operating revenues				
Electric utility	$ 2,154,383	$ 1,919,695	$ 4,127,697	$ 3,735,498
Natural gas utility	443,613	330,868	1,477,740	1,258,290
Other	17,519	16,729	38,466	37,166
Total operating revenues	2,615,515	2,267,292	5,643,903	5,030,954
Operating expenses				
Electric fuel and purchased power utility	1,269,422	1,031,899	2,357,502	2,011,470
Cost of natural gas sold and transported utility	319,800	219,574	1,142,927	960,356
Cost of sales other	4,114	3,702	9,567	9,727
Other operating and maintenance expenses	456,781	427,283	917,802	879,214
Conservation and demand-side management program expenses	29,226	20,264	64,795	41,418
Depreciation and amortization	207,774	209,176	413,381	417,071
Taxes (other than income taxes)	68,562	66,237	147,975	144,413
Total operating expenses	2,355,679	1,978,135	5,053,949	4,463,669
Operating income	259,836	289,157	589,954	567,285
Interest and other income (expense), net	9,931	(648)	18,815	168
Allowance for funds used during construction - equity	14,939	8,695	29,159	16,271
Interest charges and financing costs				
Interest charges includes other financing costs of $5,141, $5,343, $10,132 and $11,594, respectively	133,723	125,672	265,894	252,975
Interest and penalties related to COLI settlement		41,211		41,211
Allowance for funds used during construction - debt	(9,596)	(8,442)	(19,123)	(15,648)
Total interest charges and financing costs	124,127	158,441	246,771	278,538
Income from continuing operations before income taxes	160,579	138,763	391,157	305,186
Income taxes	55,106	71,068	131,689	118,977
Income from continuing operations	105,473	67,695	259,468	186,209
Income (loss) from discontinued operations, net of tax	99	1,082	(778)	2,279
Net income	105,572	68,777	258,690	188,488
Dividend requirements on preferred stock	1,060	1,060	2,120	2,120
Earnings available to common shareholders	$ 104,512	$ 67,717	$ 256,570	$ 186,368

Weighted average common shares outstanding								
Basic		430,811		412,710		430,187		410,370
Diluted		435,868		432,861		435,360		432,471
Earnings per share basic								
Income from continuing operations	$	0.24	$	0.16	$	0.60	$	0.44
Income from discontinued operations								0.01
Earnings per share basic	$	0.24	$	0.16	$	0.60	$	0.45
Earnings per share diluted								
Income from continuing operations	$	0.24	$	0.16	$	0.59	$	0.44
Income from discontinued operations								0.01
Earnings per share diluted	$	0.24	$	0.16	$	0.59	$	0.45
Cash dividends declared per common share	$	0.24	$	0.23	$	0.47	$	0.45

See Notes to Consolidated Financial Statements

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

(Thousands of Dollars)

	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Operating activities		
Net income	$ 258,690	$ 188,488
Remove loss (income) from discontinued operations	778	(2,279)
Adjustments to reconcile net income to cash provided by operating activities:		
Depreciation and amortization	453,699	444,673
Nuclear fuel amortization	31,045	23,636
Deferred income taxes	137,430	97,595
Amortization of investment tax credits	(3,895)	(4,855)
Allowance for equity funds used during construction	(29,159)	(16,271)
Undistributed equity in earnings of unconsolidated affiliates	(1,281)	(1,413)
Share-based compensation expense	10,512	9,677
Net realized and unrealized hedging and derivative transactions	(7,887)	3,682
Changes in operating assets and liabilities:		
Accounts receivable	86,265	72,146
Accrued unbilled revenues	145,774	(36,224)
Inventories	26,523	97,082
Recoverable purchased natural gas and electric energy costs	(113,318)	203,726
Other current assets	23,046	(7,415)
Accounts payable	(36,874)	(148,909)
Net regulatory assets and liabilities	8,742	(28,491)
Other current liabilities	(122,750)	19,898
Change in other noncurrent assets	(3,370)	(36,740)
Change in other noncurrent liabilities	(40,192)	32,082
Operating cash flows provided by (used in) discontinued operations	(20,576)	28,593
Net cash provided by operating activities	803,202	938,681
Investing activities		
Utility capital/construction expenditures	(1,039,957)	(978,651)
Allowance for equity funds used during construction	29,159	16,271
Purchase of investments in external decommissioning fund	(441,802)	(313,102)
Proceeds from the sale of investments in external decommissioning fund	420,106	291,406
Nonregulated capital expenditures and asset acquisitions	(370)	(301)
Investment in WYCO	(37,793)	
Change in restricted cash	2,197	4,470
Other investments	3,437	8,898
Net cash used in investing activities	(1,065,023)	(971,009)
Financing activities		
Repayment of short-term borrowings net	(415,678)	(6,069)
Proceeds from issuance of long-term debt	892,710	344,063
Repayment of long-term debt, including reacquisition premiums	(1,825)	(102,064)
Early participation payments on debt exchange		(4,859)
Proceeds from issuance of common stock	3,015	7,683
Dividends paid	(199,755)	(183,702)
Net cash provided by financing activities	278,467	55,052

Net increase in cash and cash equivalents		16,646		22,724
Net increase (decrease) in cash and cash equivalents discontinued operations		3,105		(18,603)
Cash and cash equivalents at beginning of year		51,120		37,458
Cash and cash equivalents at end of quarter	$	70,871	$	41,579
Supplemental disclosure of cash flow information:				
Cash paid for interest (net of amounts capitalized)	$	224,278	$	154,251
Cash paid for income taxes (net of refunds received)		47,396		7,007
Supplemental disclosure of non-cash investing transactions:				
Property, plant and equipment additions in accounts payable	$	30,943	$	38,115
Supplemental disclosure of non-cash financing transactions:				
Issuance of common stock for reinvested dividends and 401(k) plans	$	41,626	$	37,569
Issuance of common stock for senior convertible notes				125,632

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	June 30, 2008	Dec. 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 70,871	$ 51,120
Accounts receivable, net	865,315	951,580
Accrued unbilled revenues	586,185	731,959
Inventories	505,087	531,610
Recoverable purchased natural gas and electric energy costs	186,733	73,415
Derivative instruments valuation	198,193	94,554
Prepayments and other	171,321	244,134
Current assets held for sale and related to discontinued operations	104,555	128,821
Total current assets	2,688,260	2,807,193
Property, plant and equipment, net	17,278,841	16,675,689
Other assets:		
Nuclear decommissioning fund and other investments	1,356,513	1,372,098
Regulatory assets	1,114,234	1,115,443
Prepaid pension asset	588,535	568,055
Derivative instruments valuation	352,942	383,861
Other	178,855	142,078
Noncurrent assets held for sale and related to discontinued operations	160,463	120,310
Total other assets	3,751,542	3,701,845
Total assets	$ 23,718,643	$ 23,184,727
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 741,088	$ 637,535
Short-term debt	672,882	1,088,560
Accounts payable	1,028,894	1,079,345
Taxes accrued	153,742	240,443
Dividends payable	103,404	99,682
Derivative instruments valuation	120,645	58,811
Other	373,664	419,209
Current liabilities held for sale and related to discontinued operations	16,496	17,539
Total current liabilities	3,210,815	3,641,124
Deferred credits and other liabilities:		
Deferred income taxes	2,622,563	2,553,526
Deferred investment tax credits	109,019	112,914
Asset retirement obligations	1,352,053	1,315,144
Regulatory liabilities	1,422,284	1,389,987
Pension and employee benefit obligations	522,447	576,426
Derivative instruments valuation	346,378	384,419
Customer advances	321,003	305,239
Other	172,454	137,422
Noncurrent liabilities held for sale and related to discontinued operations	20,621	20,384
Total deferred credits and other liabilities	6,888,822	6,795,461

Commitments and contingent liabilities				
Capitalization:				
Long-term debt		7,139,556		6,342,160
Preferred stockholders equity authorized 7,000,000 shares of $100 par value; outstanding shares: 1,049,800		104,980		104,980
Common stockholders equity authorized 1,000,000,000 shares of $2.50 par value; outstanding shares: June 30, 2008 430,916,578; Dec. 31, 2007 428,782,700		6,374,470		6,301,002
Total liabilities and equity	$	23,718,643	$	23,184,727

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY
AND COMPREHENSIVE INCOME

(UNAUDITED)
(Thousands)

	Common Stock Issued		Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
	Shares	Par Value				
Three months ended June 30, 2008 and 2007						
Balance at March 31, 2007	408,861	$ 1,022,152	$ 4,061,586	$ 801,148	$ (16,635)	$ 5,868,251
Net income				68,777		68,777
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $104					406	406
Net derivative instrument fair value changes during the period, net of tax of $5,856					6,935	6,935
Comprehensive income for the period						76,118
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(96,486)		(96,486)
Issuances of common stock	10,649	26,622	109,166			135,788
Share-based compensation			5,081			5,081
Balance at June 30, 2007	419,510	$ 1,048,774	$ 4,175,833	$ 772,379	$ (9,294)	$ 5,987,692
Balance at March 31, 2008	430,512	$ 1,076,281	$ 4,293,053	$ 1,015,317	$ (27,603)	$ 6,357,048
Net income				105,572		105,572
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $241					247	247
Net derivative instrument fair value changes during the period, net of tax of $723					908	908
Unrealized loss - marketable securities, net of tax of $(67)					(101)	(101)
Comprehensive income for the period						106,626
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(102,341)		(102,341)
Issuances of common stock	405	1,011	7,489			8,500
Share-based compensation			5,697			5,697
Balance at June 30, 2008	430,917	$ 1,077,292	$ 4,306,239	$ 1,017,488	$ (26,549)	$ 6,374,470

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XCEL ENERGY INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

(UNAUDITED)
(Thousands)

	Common Stock Issued		Additional		Accumulated	Total
	Shares	Par Value	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Stockholders Equity
Six months ended June 30, 2008 and 2007						
Balance at Dec. 31, 2006	407,297	$ 1,018,242	$ 4,043,657	$ 771,249	$ (16,326)	$ 5,816,822
FIN 48 adoption				2,207		2,207
Net income				188,488		188,488
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $229					893	893
Net derivative instrument fair value changes during the period, net of tax of $3,968					6,135	6,135
Unrealized gain - marketable securities, net of tax of $2					4	4
Comprehensive income for the period						195,520
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(187,445)		(187,445)
Issuances of common stock	12,213	30,532	121,428			151,960
Share-based compensation			10,748			10,748
Balance at June 30, 2007	419,510	$ 1,048,774	$ 4,175,833	$ 772,379	$ (9,294)	$ 5,987,692
Balance at Dec. 31, 2007	428,783	$ 1,071,957	$ 4,286,917	$ 963,916	$ (21,788)	$ 6,301,002
EITF 06-4 adoption, net of tax of $(1,038)				(1,640)		(1,640)
Net income				258,690		258,690
Changes in unrecognized amounts of pension and retiree medical benefits, net of tax of $876					58	58
Net derivative instrument fair value changes during the period, net of tax of $(1,067)					(4,718)	(4,718)
Unrealized loss - marketable securities, net of tax of $(67)					(101)	(101)
Comprehensive income for the period						253,929
Dividends declared:						
Cumulative preferred stock				(2,120)		(2,120)
Common stock				(201,358)		(201,358)
Issuances of common stock	2,134	5,335	7,541			12,876
Share-based compensation			11,781			11,781

Balance at June 30, 2008	430,917	$	1,077,292	$	4,306,239	$	1,017,488	$	(26,549)	$ 6,374,470

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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 the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of June 30, 2008, and Dec. 31, 2007; the results of its operations and changes in stockholders equity for the three and six months ended June 30, 2008 and 2007; and its cash flows for the six months ended June 30, 2008 and 2007. 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.

1. Significant Accounting Policies

Except to the extent updated or described below, the significant accounting policies set forth in Note 1 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, appropriately represent, in all material respects, the current status of accounting policies and are incorporated herein by reference.

Fair Value Measurements Xcel Energy presents interest rate derivatives, commodity derivatives, and nuclear decommissioning fund assets at estimated fair values in its consolidated financial statements. For interest rate derivatives, broker quotes are used to establish fair value. For commodity derivatives, the most observable inputs available are used to determine the fair value of each contract. In the absence of a quoted price for an identical contract in an active market, Xcel Energy may use broker quotes for identical or similar contracts, or internally prepared valuation models to determine fair value. For the nuclear decommissioning fund, published trading data, broker quotes and market inputs are utilized to estimate fair value for each class of security.

2. Recently Issued Accounting Pronouncements

Statement of Financial Accounting Standards (SFAS) No. 157 Fair Value Measurements (SFAS No. 157) In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, which provides a single definition of fair value, together with a framework for measuring it, and requires additional disclosure about the use of fair value to measure assets and liabilities. SFAS No. 157 also emphasizes that fair value is a market-based measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 was effective for financial statements issued for fiscal years beginning after Nov. 15, 2007.

As of Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for all assets and liabilities measured at fair value except for non-financial assets and non-financial liabilities measured at fair value on a non-recurring basis, as permitted by FASB Staff Position No. 157-2. The adoption did not have a material impact on its consolidated financial statements. For additional discussion and SFAS No. 157 required disclosures see Note 11 to the consolidated financial statements.

The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115 (SFAS No. 159) In February 2007, the FASB issued SFAS No. 159, which provides companies with an option to measure, at specified election dates, many financial instruments and certain other items at fair value that are not currently measured at fair value. A company that adopts SFAS No. 159 will report unrealized gains and losses on items, for which the fair value option has been elected, in earnings at each subsequent reporting date. This statement also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. This statement was effective for fiscal years beginning after Nov. 15, 2007. Effective Jan. 1, 2008, Xcel Energy adopted SFAS No. 159 and the adoption did not have a material impact on its consolidated financial statements.

Business Combinations (SFAS No. 141 (revised 2007)) In December 2007, the FASB issued SFAS No. 141R, which establishes principles and requirements for how an acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest; recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of an entity s fiscal year that begins on or after Dec. 15, 2008. Xcel Energy will evaluate the impact of SFAS No. 141R on its consolidated financial statements for any potential business combinations subsequent to Jan. 1, 2009.

Noncontrolling Interests in Consolidated Financial Statements, an Amendment of Accounting Research Bulletin (ARB) No. 51 (SFAS No. 160) In December 2007, the FASB issued SFAS No. 160, which establishes accounting and reporting standards that require the ownership interest in subsidiaries held by parties other than the parent be clearly identified and presented in the consolidated balance sheets within equity, but separate from the parent s equity; the amount of consolidated net income attributable to

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the parent and the noncontrolling interest be clearly identified and presented on the face of the consolidated statement of earnings; and changes in a parent s ownership interest while the parent retains its controlling financial interest in its subsidiary be accounted for consistently. This statement is effective for fiscal years beginning on or after Dec. 15, 2008. Xcel Energy is currently evaluating the impact of SFAS No. 160 on its consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161) In March 2008, the FASB issued SFAS No. 161, which is intended to enhance disclosures to help users of the financial statements better understand how derivative instruments and hedging activities affect an entity s financial position, financial performance and cash flows. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, to require disclosures of objectives and strategies for using derivatives, gains and losses on derivative instruments, and credit-risk-related contingent features in derivative agreements. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after Nov. 15, 2008, with early application encouraged. Xcel Energy is currently evaluating the impact of adoption of SFAS No. 161 on its consolidated financial statements.

The Hierarchy of Generally Accepted Accounting Principles (GAAP) (SFAS No. 162) In May 2008, the FASB issued SFAS No. 162, which establishes the GAAP hierarchy, identifying the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements. SFAS No. 162 is effective 60 days following the SEC approval of the Public Company Accounting Oversight Board amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles.* Xcel Energy does not believe that implementation of SFAS No. 162 will have any impact on its consolidated financial statements.

Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements (Emerging Issues Task Force (EITF) Issue No. 06-4) In June 2006, the EITF reached a consensus on EITF No. 06-4, which provides guidance on the recognition of a liability and related compensation costs for endorsement split-dollar life insurance policies that provide a benefit to an employee that extends to postretirement periods. Therefore, this EITF would not apply to a split-dollar life insurance arrangement that provides a specified benefit to an employee that is limited to the employee s active service period with an employer. EITF No. 06-4 was effective for fiscal years beginning after Dec. 15, 2007, with earlier application permitted. Upon adoption of EITF No. 06-4 on Jan. 1, 2008, Xcel Energy recorded a liability of $1.6 million, net of tax, as a reduction of retained earnings. Thereafter, changes in the liability are reflected in operating results.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards (EITF No. 06-11) In June 2007, the EITF reached a consensus on EITF No. 06-11, which states that an entity should recognize a realized tax benefit associated with dividends on nonvested equity shares and nonvested equity share units charged to retained earnings as an increase in additional paid in capital. The amount recognized in additional paid in capital should be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. EITF No. 06-11 should be applied prospectively to income tax benefits of dividends on equity-classified share-based payment awards that are declared in fiscal years beginning after Dec. 15, 2007. The adoption of EITF No. 06-11 did not have a material impact on Xcel Energy s consolidated financial statements.

3. Selected Balance Sheet Data

(Thousands of Dollars)	**June 30, 2008**	**Dec. 31, 2007**
Accounts receivable, net:		
Accounts receivable	$ 912,737	$ 1,000,981
Less allowance for bad debts	(47,422)	(49,401)

	$	865,315	$	951,580
Inventories:				
Materials and supplies	$	162,902	$	152,770
Fuel		169,946		142,764
Natural gas		172,239		236,076
	$	505,087	$	531,610

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(Thousands of Dollars)	June 30, 2008	Dec. 31, 2007
Property, plant and equipment, net:		
Electric utility plant	$ 21,006,479	$ 20,313,313
Natural gas utility plant	2,995,682	2,946,455
Common utility and other property	1,498,667	1,475,325
Construction work in progress	1,866,796	1,810,664
Total property, plant and equipment	27,367,624	26,545,757
Less accumulated depreciation	(10,317,482)	(10,049,927)
Nuclear fuel	1,551,114	1,471,229
Less accumulated amortization	(1,322,415)	(1,291,370)
	$ 17,278,841	$ 16,675,689

4. Discontinued Operations

A summary of the subsidiaries presented as discontinued operations is discussed below. Results of operations for divested businesses are reported, for all periods presented, as discontinued operations. In addition, the remaining assets and liabilities related to the businesses divested or discontinued have been reclassified to assets and liabilities held for sale and related to discontinued operations in the consolidated balance sheets. The majority of current and noncurrent assets related to discontinued operations are deferred tax assets and net operating loss (NOL) and tax credit carryforwards, originally from discontinued operations, that will be deductible in future years.

Nonregulated Subsidiaries

Seren Innovations Inc., NRG Energy, Inc., e prime, Xcel Energy International, Utility Engineering, and Quixx, which were all divested or sold in 2006 or earlier, continue to have activity and balances reflected on Xcel Energy s financial statements as reported in the tables below.

Summarized Financial Results of Discontinued Operations

(Thousands of Dollars)	2008	2007
Three months ended June 30,		
Operating income, interest and other income, net	$ 231	$ 1,566
Pretax income from discontinued operations	231	1,566
Income tax expense	132	484
Net income from discontinued operations	$ 99	$ 1,082
Six months ended June 30,		
Operating revenues	$	$ 36
Operating income, interest and other income, net	200	1,799
Pretax income from discontinued operations	200	1,835
Income tax expense (benefit)	978	(444)
	$ (778)	$ 2,279

Net income (loss) from discontinued operations

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The major classes of assets and liabilities held for sale and related to discontinued operations are as follows:

(Thousands of Dollars)		June 30, 2008		Dec. 31, 2007
Cash	$	9,897	$	6,792
Accounts receivable, net		768		913
Deferred income tax benefits		81,276		118,919
Other current assets		12,614		2,197
Current assets related to discontinued operations	$	104,555	$	128,821
Deferred income tax benefits	$	135,015	$	97,284
Other noncurrent assets		25,448		23,026
Noncurrent assets related to discontinued operations	$	160,463	$	120,310
Accounts payable	$	989	$	1,060
Other current liabilities		15,507		16,479
Current liabilities related to discontinued operations	$	16,496	$	17,539
Noncurrent liabilities related to discontinued operations	$	20,621	$	20,384

5. Income Taxes

Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109 (FIN 48) Xcel Energy files a consolidated federal income tax return and 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.

In the first quarter of 2008, the Internal Revenue Service (IRS) completed an examination of Xcel Energy s federal income tax returns for 2004 and 2005 (and research credits for 2003). The IRS did not propose any material adjustments for those tax years. Tax year 2004 is the earliest open year and the statute of limitations applicable to Xcel Energy s 2004 federal income tax return remains open until Dec. 31, 2009. Xcel Energy expects the IRS to commence their examination of tax years 2006 and 2007 in the third quarter of 2008.

In the first quarter of 2008, the state of Minnesota concluded an income tax audit through tax year 2001 and the state of Texas concluded an audit through tax year 2005. No material adjustments were proposed for these state audits. As of June 30, 2008, Xcel Energy s earliest open tax years in which an audit can be initiated by state taxing authorities in its major operating jurisdictions are as follows: Colorado-2003, Minnesota-2004, Texas-2004 and Wisconsin-2003. There currently are no state income tax audits in progress.

The amount of unrecognized tax benefits reported in continuing operations was $26.3 million on Dec. 31, 2007, and $28.0 million on June 30, 2008. The amount of unrecognized tax benefits reported in discontinued operations was $4.3 million on Dec. 31, 2007 and $4.3 million on June 30, 2008. These unrecognized tax benefit amounts were reduced by the tax benefits associated with NOL and tax credit carryovers reported in continuing operations of $7.8 million on Dec. 31, 2007 and $9.3 million on June 30, 2008 and NOL and tax credit carryovers reported in discontinued operations of $17.8 million on Dec. 31, 2007 and $19.6 million on June 30, 2008.

The unrecognized tax benefit balance reported in continuing operations included $9.8 million and $8.0 million of tax positions on Dec. 31, 2007 and June 30, 2008, respectively, which if recognized would affect the annual effective tax rate. In addition, the unrecognized tax benefit balance reported in continuing operations included $16.5 million and $20.0 million of tax positions on Dec. 31, 2007 and June 30, 2008, respectively, 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 effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The increase in the unrecognized tax benefit balance reported in continuing operations of $1.9 million from April 1, 2008 to June 30, 2008, was due to the addition of similar uncertain tax positions related to ongoing activity. Xcel Energy s amount of unrecognized tax benefits for continuing operations could significantly change in the next 12 months when the IRS and state audits resume. However, at this time, it is not reasonably possible to estimate an overall range of possible change.

The liability for interest related to unrecognized tax benefits is partially offset by the interest benefit associated with NOL and tax credit carryovers. The amount of interest expense related to unrecognized tax benefits reported within interest charges in continuing operations in the second quarter of 2008 was $0.4 million. The liability for interest related to unrecognized tax benefits reported in continuing operations was $5.8 million on Dec. 31, 2007 and $5.0 million on June 30, 2008. The amount of interest income related to unrecognized tax benefits reported within interest charges in discontinued operations in the second quarter of 2008 was $0.3 million.

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The receivable for interest related to unrecognized tax benefits reported in discontinued operations was $0.5 million on Dec. 31, 2007 and $1.0 million on June 30, 2008.

No amounts were accrued for penalties in the second quarter of 2008. The liability for penalties related to unrecognized tax benefits reported in continuing operations was $1.0 million on Dec. 31, 2007 and June 30, 2008.

Other Income Tax Matters The effective tax rate for continuing operations was 34.3 percent for the second quarter of 2008, compared with 51.2 percent for the same period in 2007. The higher effective tax rate for second quarter 2007 was primarily due to the corporate-owned life insurance (COLI) settlement in that quarter. This was partially offset by an increase in the forecasted annual effective tax rate for 2008, which was largely a result of PSR Investments, Inc. (PSRI) terminating the COLI program in 2007. Without these charges and benefits, the effective tax rate for the second quarters of 2008 and 2007 would have been 35.2 percent and 37.8 percent, respectively.

The effective tax rate for continuing operations was 33.7 percent for the first six months of 2008, compared with 39.0 percent for the same period in 2007. The higher effective tax rate for the first six months of 2007 was primarily due to the COLI settlement. This was partially offset by an increase in the forecasted annual effective tax rate for 2008, which was largely a result of PSRI terminating the COLI program in 2007. Without these charges and benefits, the effective tax rate for the first six months of 2008 and 2007 would have been 33.8 percent and 35.6 percent, respectively.

COLI On June 19, 2007, a settlement in principle was reached between Xcel Energy and representatives of the United States Government regarding Public Service Company of Colorado s (PSCo) right to deduct interest expense on policy loans related to its COLI program that insured lives of certain PSCo employees. These COLI policies were owned and managed by PSRI, a wholly owned subsidiary of PSCo.

In September 2007, Xcel Energy and the United States finalized a settlement, which terminated the tax litigation pending between the parties. As a result of the settlement, the lawsuit filed by Xcel Energy in the United States District Court has been dismissed and the Tax Court proceedings are in the process of being dismissed. Xcel Energy paid the government a total of $64.4 million in full settlement of the government s claims for tax, penalty, and interest for tax years 1993-2007.

6. Rate Matters

Except to the extent noted below, the circumstances set forth in Note 14 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007 appropriately represent, in all material respects, the current status of other rate matters, and are incorporated herein by reference. The following include unresolved proceedings that are material to Xcel Energy s financial position.

NSP-Minnesota

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

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Recovery (TCR) Rider In November 2006, the MPUC approved a TCR rider pursuant to legislation, which allows annual adjustments to retail electric rates to provide recovery of incremental transmission investments between rate cases. In December 2007, NSP-Minnesota filed adjustments to the TCR rate factors and implemented a rider to recover $18.5 million beginning Jan. 1, 2008. In March 2008, the MPUC approved the 2008 cost recovery, but requiring certain procedural changes for future TCR filings if costs are disputed. NSP-Minnesota filed the required compliance filing in April 2008.

Renewable Energy Standard (RES) Rider In March 2008, the MPUC approved a RES Rider to recover the costs associated with utility-owned projects implemented in compliance with the RES adopted by the 2007 Minnesota legislature, and it was implemented on April 1, 2008. Under the rider, NSP-Minnesota could recover up to approximately $14.5 million in 2008 attributable to the Grand Meadow wind farm, a 100-megawatt (MW) wind project, subject to true-up.

Annual Automatic Adjustment Report for 2007 In September 2007, NSP-Minnesota filed its annual automatic adjustment reports for July 1, 2006 through June 30, 2007, which is the basis for the MPUC review of charges that flow through the fuel clause adjustment (FCA) and purchased gas adjustment (PGA) mechanisms. During that time period, $1.2 billion in fuel and purchased energy costs, including $384 million of Midwest Independent Transmission System Operator, Inc. (MISO) charges were recovered from electric customers through the FCA. In addition, approximately $590 million of purchased natural gas and transportation costs were recovered through the PGA. The 2007 annual automatic adjustment reports are pending comments and MPUC action. The

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Minnesota Office of Energy Security (OES) submitted its comments in this proceeding on June 30, 2008. While the OES made several recommendations regarding assignment of wholesale and retail costs for the recovery period and future periods, none of these recommendations have a material financial impact, as NSP-Minnesota currently returns all margins to ratepayers.

Other

Nuclear Refueling Outage Costs In November 2007, NSP-Minnesota filed a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request seeks approval to amortize refueling outage costs over the period between refueling outages to better match revenues and expenses. This request, if approved, would reduce 2008 expenses for NSP-Minnesota jurisdiction by approximately $25 million due to deferral and amortization over an 18-month period versus expensed as incurred. In March 2008, the OES issued comments indicating it did not object to adoption of the proposal, subject to conditions. The Minnesota Office of Attorney General filed comments opposing implementation of this change outside of a rate case. NSP-Minnesota filed reply comments in support of its proposal, and MPUC action is pending.

Pending Regulatory Proceedings North Dakota Public Service Commission (NDPSC) and South Dakota Public Utilities Commission (SDPUC)

NSP-Minnesota North Dakota Electric Rate Case In December 2007, NSP-Minnesota filed a request with the NDPSC to increase North Dakota retail electric rates by $20.5 million, which is an $18.2 million impact to NSP-Minnesota due to the transfer of certain costs and revenues between base rates and the fuel cost recovery mechanism. The request was based on an 11.50 percent return on equity (ROE), an equity ratio of 51.77 percent, and a rate base of approximately $242 million. Interim rates of $17.2 million became effective in February 2008.

NSP-Minnesota and the NDPSC staff reached a stipulation settlement in the rate case in which both parties recommended an ROE of 10.75 percent, with a sharing mechanism for earnings above 10.75 percent. This stipulation settlement is subject to approval by the NDPSC. In June 2008, NSP-Minnesota filed rebuttal testimony and reduced its requested rate increase to $17.9 million, a net impact of $15.7 million to NSP-Minnesota, which reflects a 10.75 percent ROE and other adjustments.

Evidentiary hearings were held June 23-25, 2008 in the pending electric rate case application in North Dakota. The updated NDPSC staff s overall recommendation following the hearing is a base rate increase of $4.9 million, a net impact of $2.5 million to NSP-Minnesota, with recommended disallowances for costs associated with NSP-Minnesota s compliance with Minnesota renewable energy requirements, investments in environmental improvements and power plant life extensions through NSP-Minnesota s Metropolitan Emissions Reduction Program (MERP), and recommended changes in treatment of depreciation costs. Briefs are expected to be filed on Aug. 22, 2008, with reply briefs due Sept. 12, 2008. Final rates are expected to be effective in the fall of 2008.

Nuclear Refueling Outage Costs In late 2007, NSP-Minnesota filed with both the NDPSC and SDPUC a request asking for a change in the recovery method for costs associated with refueling outages at its nuclear plants. The request is comparable to that filed with the MPUC. In February 2008, the NDPSC approved the request, indicating that appropriate cost recovery levels would be determined in the pending electric rate case. The SDPUC has not acted on the petition.

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

MISO Long-Term Transmission Pricing In October 2005, MISO filed a proposed change to its Transmission and Energy Markets Tariff of MISO (TEMT) to regionalize future cost recovery of certain high voltage transmission projects to be constructed for reliability improvements. The tariff, called the Regional Expansion Criteria Benefits phase I (RECB I) and a subsequent proposal based on regional economic benefits (RECB II), would recover varying percentages of eligible reliability transmission costs from all transmission service customers in the MISO 15 state region. In November 2006, the FERC issued an order accepting the RECB I tariff, including the 20 percent limitation, which is the cap on the portion of transmission expansion costs that would be regionalized and recovered from all loads in the MISO region, with 80 percent allocated to the pricing zone where the transmission facilities are constructed. In December 2006, the Public Service Commission of Wisconsin (PSCW) and other parties filed an appeal of the RECB I order to the U.S. federal Court of Appeals for the District of Columbia. The appeal is pending.

In March 2007, the FERC issued an order approving most aspects of the RECB II proposal. Transmission service rates in the MISO region presently use a rate design in which the transmission cost depends on the location of the load being served (referred to as license plate rates). Costs of existing transmission facilities are thus not regionalized. MISO and its transmission owners filed a successor rate methodology in August 2007, to be effective February 2008. Other entities sought to regionalize some of these costs. The impact of the regionalization of future facilities would depend on the specific facilities placed in service. In January 2008, the FERC issued an order accepting the MISO filing to continue use of license plate rates for existing facilities and RECB (limited regionalization) pricing for certain new facilities. The requests for rehearing are pending FERC action.

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NSP-Wisconsin

Pending and Recently Concluded Regulatory Proceedings   PSCW

Base Rate

Electric and Gas Rate Case In January 2008, the PSCW issued the final written order in NSP-Wisconsin s 2008 test year rate case, approving an electric rate increase of approximately $39.4 million, or 8.1 percent, and a natural gas rate increase of $5.3 million, or 3.3 percent. The rate increase was based on a 10.75 percent ROE and a 52.5 percent common equity ratio. New rates went into effect Jan. 9, 2008.

On Aug. 1, 2008, NSP-Wisconsin filed an application with the PSCW requesting authority to increase retail electric rates by $47.1 million, which represents an overall increase of 8.6 percent. In the application, NSP-Wisconsin requested the PSCW to reopen the 2008 base rate case for the limited purpose of adjusting 2009 base electric rates to reflect forecast increases in production and transmission costs, as authorized by the PSCW.

The requested increase in electric rates is related to investments in cleaner sources of energy and transmission lines to reliably meet customers electric demand and increasing costs for fuel and purchased power. No changes are being requested to the capital structure or authorized ROE authorized by the PSCW in the 2008 base rate case.

Public hearings to address NSP-Wisconsin s rate request will be held later this fall at the PSCW. No specific dates for hearings or prehearing conferences have been scheduled as of this time.

Other

2008 Electric Fuel Cost Recovery On May 2, 2008, the PSCW approved NSP-Wisconsin s request to increase Wisconsin retail electric rates on an interim basis. The PSCW approved $19.7 million, or 3.8 percent, on an annual basis, to recover increases in fuel and purchased power costs. NSP-Wisconsin expects that the surcharge will generate approximately $13 million in additional revenue in 2008. The increase in fuel costs is primarily driven by fuel and purchased power costs, including replacement power costs associated with unplanned plant outages. Fuel costs for the remainder of 2008 are expected to be significantly higher than approved by the PSCW in NSP-Wisconsin s 2008 rate case. The increased rates went into effect May 6, 2008. The revenues that NSP-Wisconsin collects are subject to refund with interest at a rate of 10.75 percent, pending PSCW review and final approval.

Fuel Cost Recovery Rulemaking In June 2006, the PSCW opened a rulemaking docket to address potential revisions to the electric fuel cost recovery rules. Wisconsin statutes prohibit the use of automatic adjustment clauses by large investor-owned electric public utilities. The statutes authorize the PSCW to approve a rate increase for these utilities to allow for the recovery of costs caused by an emergency or extraordinary increase in the cost of fuel.

In August 2007, the PSCW staff issued its draft revisions to the fuel rules and requested comments. The proposed rules incorporate a plan year fuel cost forecast, deferred accounting for differences between actual and forecast costs (if the difference is greater than 2 percent), and an after the fact reconciliation proceeding to allow the opportunity to recover or refund the deferred balance.

On July 3, 2008, the PSCW officially issued its proposed revisions to the fuel rules for public comment, and set a hearing date of August 4, 2008. The proposed revisions to the rules are substantively the same as the version issued in August 2007, described above. If approved as proposed, the new rules would be effective with rate requests filed after January 1, 2009.

Bay Front Emission Controls Certificate of Authority In March 2008, the PSCW issued a certificate of authority and order approving NSP-Wisconsin s application to install equipment relating to combustion improvement and nitrogen oxide (NOx) emission controls in boilers 1 and 2 at the Bay Front power plant in Ashland County, Wisconsin. Construction began in May and is expected to be completed in the fall of 2008.

PSCo

Pending and Recently Concluded Regulatory Proceedings Colorado Public Utilities Commission (CPUC)

Electric, Purchased Gas and Resource Adjustment Clauses

Transmission Cost Adjustment Rider In September 2007, PSCo filed with the CPUC a request to implement a transmission cost adjustment rider (TCA), which would recover approximately $18.2 million in 2008. This filing was pursuant to recently enacted legislation, which entitled public utilities to recover, through a separate rate adjustment clause, the costs that they prudently incur in planning, developing and completing the construction or expansion of transmission.

In December 2007, the CPUC approved PSCo s application to implement the TCA. The CPUC limited the scope of the costs that could be recovered through the rider during 2008 to only those costs associated with transmission investment made after the new legislation authorizing the rider became effective on March 26, 2007. The CPUC also will require PSCo to base its revenue requirement calculation on a thirteen-month average net transmission plant balance. As a result of the CPUC s decision, PSCo implemented a rider on Jan. 1, 2008, expected to recover approximately $4.5 million in 2008.

Enhanced Demand Side Management (DSM) Program In October 2007, PSCo filed an application with the CPUC for approval to implement an expanded DSM program and to revise its DSM cost adjustment mechanism to include current cost recovery and incentives designed to reward PSCo for successfully implementing cost-effective DSM programs and measures. In July 2008, the CPUC issued an order approving PSCo s proposal to expand the DSM program and recover 100 percent of its forecasted expenses associated with the DSM program during the year in which the rider is in effect, beginning in 2009. An incentive mechanism was also approved to reward PSCo for meeting and exceeding program goals.

Pending and Recently Concluded Regulatory Proceedings FERC

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 the period Dec. 25, 2000 through June 20, 2001. PSCo supplied energy to the Pacific Northwest markets during this period and has been an active participant in the hearings. In September 2001, the presiding administrative law judge (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 regarding the use of certain strategies and how they may have impacted the markets in the Pacific Northwest markets. For the referenced period, parties have claimed that the total amount of transactions with PSCo subject to refund are $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 Ninth Circuit remanded the proceeding back to the FERC. The court of appeals preliminarily determined that it had jurisdiction to review the FERC s decision not to order refunds and remanded the case back to the FERC, directing that the FERC consider evidence that had been presented regarding intentional market manipulation in the California markets and its potential ties to transactions in the Pacific Northwest. The court of appeals also indicated that the FERC should consider other rulings addressing overcharges in the California organized markets. The FERC has yet to act on this order on remand.

PSCo Wholesale Rate Case In February 2008, PSCo requested a $12.5 million, or 5.88 percent, increase in wholesale rates, based on 11.5 percent requested ROE. The $12.5 million total increase was composed of $8.8 million of traditional base rate recovery and $3.7 million of construction work in progress recovery for the Comanche 3 and Fort St. Vrain projects. The increase is applicable to all wholesale firm service customers with the exception of Intermountain Rural Electric Cooperative, which would be under a rate moratorium until January 2009.

In March 2008, PSCo reached an agreement with Rural Electric Association (REA) customers Holy Cross, Yampa Valley and Grand Valley, which resolved all issues based on a black box settlement with an implied ROE of 10.4 percent. Parties filed the settlement with the FERC on April 17, 2008, with rates effective May 1, 2008. PSCo has reached an agreement with the cities of Burlington, Center and Aquila under the same substantive terms and conditions as the REA settlement. This settlement was filed with the FERC on April 25, 2008. The settlements provide for:

- A traditional annual rate base rate increase of $6.6 million with allowance for funds used during construction continuing for Comanche and Fort St. Vrain.
- Implementation of new rates several months earlier than is typical in a disputed filing.

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- The ability to implement rates in PSCo s next general rate case that will involve Comanche 3 costs upon a nominal suspension.

The FERC approved the settlement agreements on June 19, 2008.

SPS

Pending and Recently Concluded Regulatory Proceedings Public Utility Commission of Texas (PUCT)

Base Rate

Texas Retail Base Rate Case On June 12, 2008, SPS filed with the PUCT, and the 80 cities in SPS Texas service territory with original rate jurisdiction, a request for a Texas system retail electric general rate increase.

The filing requests an overall increase in annual revenues of approximately $61.3 million, or an increase of 5.9 percent. Base revenues are proposed to increase by $94.4 million, while fuel and purchased power revenue will decline by $33.1 million, primarily due to the fuel savings from SPS power purchases from the Hobbs generating facility, which is owned by Lea Power Partners, LLC (LPP). Hobbs is a natural gas combined cycle 604 MW plant currently being constructed in New Mexico. The LPP project had been expected to come on line in the summer of 2008.

The rate filing is based on a 2007 calendar year test year adjusted for known and measurable changes and includes a requested rate of ROE of 11.25 percent, net rate base of approximately $989.4 million allocated to the Texas retail jurisdiction, and an equity ratio of 51.0 percent.

In SPS last Texas rate case, the parties agreed that SPS seek, in this rate filing, interim rate relief of $18 million per year for the LPP purchase agreement. The interim rates are proposed to go into effect when the LPP plant comes on line. The deadline for the PUCT to act on SPS request is March 31, 2009.

The filing with the PUCT also includes a request to reconcile (i.e. seek final approval for) $1.0 billion of SPS fuel and purchased power costs for calendar years 2006 and 2007.

The following procedural schedule has been established:

- Intervenor direct testimony will be filed on Oct. 13, 2008;
- PUCT staff testimony will be filed on Oct. 21, 2008;
- PUCT staff and intervenors cross-rebuttal testimony will be filed on Oct. 28, 2008;
- SPS rebuttal testimony will be filed on Nov. 4, 2008;
- The hearing on the merits will begin on Nov. 12, 2008; and
- Final order by March 31, 2009.

Electric and Resource Adjustment Clauses

TCR Factor Rulemaking In November 2007, the PUCT adopted new rules relating to TCR factor outside of a base rate case. The rule establishes the mechanism by which SPS can request annual recovery of its reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges that are not included in existing rates. This new rule allows SPS more timely recovery of transmission cost increases in-between base rate cases.

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

Base Rate

New Mexico Electric Rate Case In July 2007, SPS filed with the NMPRC requesting a New Mexico retail electric general rate increase of $17.3 million annually, or 6.6 percent. The rate filing is based on a 2006 test year adjusted for known and measurable changes and includes a requested rate of ROE of 11.0 percent, an electric rate base of approximately $307.3 million and an equity ratio of 51.2 percent. In addition to the base rate costs described above, SPS sought to implement a rate rider to recover costs for the LPP project, which had been expected to come on line on June 1, 2008. In March 2008, SPS filed rebuttal testimony reducing the rate increase request to $16.6 million, based on a 10.7 percent ROE.

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In April 2008, hearings on SPS application were held, in which the parties agreed to move consideration of the LPP power purchase agreement costs to a future rate proceeding to be initiated by SPS this fall. SPS is expected to start taking energy beginning in late summer of 2008 when LPP reaches commercial operations.

On July 3, 2008, the hearing examiner recommended a $12.6 million electric rate increase, including a 10.14 percent ROE on a rate base of approximately $300.9 million. In addition, the hearing examiner recommended the exclusion of approximately $3.5 million of historical demand-side management costs from the New Mexico retail rate base and a reduction in certain test year expenses for preparing the rate case, for power plant outage, maintenance work and for annual incentive compensation. The parties exceptions to the recommendation were filed on July 16, 2008 and the responses to exceptions were filed on July 24, 2008. The deadline for the NMPRC to issue its order is Aug. 29, 2008.

Electric and Resource Adjustment Clauses

New Mexico Fuel Factor Continuation Filing In August 2005, SPS filed with the NMPRC requesting continuation of the use of SPS fuel and purchased power cost adjustment clause (FPPCAC) and current monthly factor cost recovery methodology. This filing was required by NMPRC rule.

Testimony was filed in the case by staff and intervenors objecting to SPS assignment of system average fuel costs to certain wholesale sales and the inclusion of certain purchased power capacity and energy payments in the FPPCAC. The testimony also proposed limits on SPS future use of the FPPCAC. Related to these issues, some intervenors requested disallowances for past periods, which in the aggregate total approximately $45 million. This claim was for the period from Oct. 1, 2001 through May 31, 2005 and does not include the value of incremental cost assigned for wholesale transactions from that date forward. Other issues in the case include the treatment of renewable energy certificates and sulfur dioxide (SO_2) allowance credit proceeds in relation to SPS New Mexico retail fuel and purchased power recovery clause.

In December 2007, SPS, the NMPRC, Occidental Permian Ltd. and the New Mexico Industrial Energy Consumers filed an uncontested settlement of this matter with the NMPRC.

- The settlement resolves all issues in the fuel continuation proceeding for total consideration of $15 million, which includes customer refunds of $11.7 million.
- At Dec. 31, 2007, a reserve had been previously established for this potential exposure, with no further expense accrual required, assuming this settlement is approved.
- The settlement would also provide for significantly greater certainty surrounding system average fuel cost assignment on a going forward basis and reduce percentages of system average cost wholesale sales between now and 2019 on a stepped down basis.
- Under the terms of the settlement, SPS anticipates additional fuel cost disallowances in 2008 and a portion of 2009 of approximately $2 million per year. It does not anticipate any future disallowances beyond this period.
- Finally, the settlement provides for SPS to continue its use of the FPPCAC subject to additional reporting provisions.

A hearing on the merits of the settlement was held in April 2008. On June 3, 2008, the hearing examiner certified the unanimous stipulation to the NMPRC. The unanimous stipulation is pending final review and approval by the NMPRC. The NMPRC has scheduled a hearing for Aug. 14, 2008 to enable the commissioners to directly question the witnesses who supported the unanimous stipulation.

Investigation of SPS Participation in Southwest Power Pool, Inc. (SPP) In October 2007, the NMPRC issued an order initiating an investigation to consider the prudence and reasonableness of SPS participation in the SPP Regional Transmission Organization (RTO). The investigation will consider the costs and benefits of RTO participation to SPS customers in New Mexico. The order required SPS to file direct testimony no later than 75 days after the completion of the hearing in the New Mexico electric rate case. SPS has been granted an extension and filed its direct testimony on July 31, 2008 with the NMPRC.

Pending and Recently Concluded Regulatory Proceedings FERC

Wholesale Rate Complaints In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer s Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, all wholesale cooperative customers of SPS, filed a rate complaint with the FERC alleging that SPS rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustment charges to such customers (the Complaint). Among other things, the complainants asserted that SPS had inappropriately allocated average fuel and purchased power costs to other wholesale customers, effectively raising the fuel cost charges to complainants. Cap Rock Energy Corporation (Cap Rock), another full-requirements customer of SPS, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental), SPS largest retail customer, intervened in the proceeding.

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In May 2006, a FERC ALJ issued an initial decision in the proceeding. The ALJ found that SPS should recalculate its wholesale fuel and purchased economic energy cost adjustment clause (FCAC) billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by deducting from such costs the incremental fuel costs attributed to SPS sales of system firm capacity and associated energy to other wholesale customers served under market-based rates during this period based on the view that such sales should be treated as opportunity sales made out of temporarily excess capacity. In addition, the ALJ made recommendations on a number of base rate issues including a 9.64 percent ROE and the use of a 3-month coincident peak (3CP) demand allocator.

Golden Spread Complaint Settlement In December 2007, SPS reached a settlement with Golden Spread (which now includes Lyntegar Electric) and Occidental regarding base rate and fuel issues raised in the complaint described above as well as a subsequent rate proceeding. In December 2007, this comprehensive offer of settlement (the Settlement) was filed with the FERC. On April 21, 2008, the FERC approved the Settlement with a minor modification to the formula rate proposed by the FERC and accepted by the parties. The Settlement provides for:

- A $1.25 million payment by SPS to Golden Spread related to resolve a dispute concerning the quantities Golden Spread was entitled to take under its existing partial requirements agreement for the years 2006 and 2007. The Settlement caps those quantities for the period 2008 through 2011. SPS is not required to make any fuel refunds to Golden Spread that were the subject of the Complaint under the terms of the Settlement.

- An extended partial requirements contract at system average cost, with a capacity amount that ramps down over the period 2012 through 2019 from 500 MW to 200 MW. The extended agreement requires that the cost assignment treatment receive Texas and New Mexico state approvals and provides for alternative pricing terms and quantities to hold SPS harmless from cost disallowances in the event that adverse regulatory treatment occurs or state approvals are not obtained. Golden Spread agreed to hold SPS harmless from any future adverse regulatory treatment regarding the proposed sale and SPS agreed to contingent payments ranging from $3 million to a maximum of $12 million, payable in 2012, in the event that there is an adverse cost assignment decision or a failure to obtain state approvals.

- Resolution of base rates in the Complaint without any adjustment to the existing rates for the period January 2005 through June 30, 2006. The Settlement also resolves all base rate issues in SPS subsequent proceeding related to the period July 1, 2006 through June 30, 2008, other than the method to be used to allocate demand related costs and provided for two sets of agreed on rates that are dependent on the ultimate resolution of that issue. If SPS prevails in its support of the 12-month coincident peak (12 CP) demand allocation method, there would be no impact to earnings for this period. If Golden Spread prevails, SPS would be required to refund Golden Spread and PNM approximately $4 million for the period through the end of 2007.

- For July 1, 2008 and beyond, Golden Spread will be under a formula rate for power supply service. The rate will be based on actual data the most recent historic year adjusted for known and measurable changes and trued up to the actual performance in the subsequent calendar year. Initially, the formula will be based on a 10.25 percent ROE and either party will have a right to seek changes to the ROE beginning with the 2009 formula rate filing. SPS and Golden Spread will share margins from its sales to West Texas Municipal Power Agency and El Paso Electric in that year but will assign system average fuel and energy costs to those agreements for purposes of calculating Golden Spread s monthly fuel cost.

Order on Wholesale Rate Complaints On April 21, 2008, the FERC issued its Order on the Complaint (the Order) applied to the remaining non-settling parties. The Order addresses base rate issues for the period from Jan. 1, 2005 through June 30, 2006 for SPS full requirements customers who pay traditional cost-based rates and requires certain refunds.

Base Rates: The FERC determined: (1) the ROE should be 9.33 percent; (2) rates should be based on a 12 CP allocator; and (3) the treatment of market based rate contracts in the test year should be to credit revenues to the cost of service rather than allocating costs to the agreements. The revenue requirement established by the FERC results in proposed revenues that are estimated to be approximately $25 million, or approximately $6.9 million below the level charged these customers during this 18-month period. Rates for full requirements customers, the New Mexico Cooperatives and Cap Rock, as well as an interruptible contract with PNM for the period beginning in July 1, 2006, are the subject of settlements that have either been approved or are pending before FERC. These settlements are described in Wholesale 2005 Power Base Rate Application below.

Fuel Clause: The FERC determined that the method for calculating fuel and purchased energy cost charges to the complaining customer is to deduct from such costs incremental fuel and purchased energy costs, which it is attributing to SPS market based intersystem sales on the basis that these are opportunity sales under its precedent. The FERC ordered that refunds of fuel cost charges based on this method of determining the FCAC should begin as of Jan. 1, 2005 (the refund

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effective date in the case). The FERC ordered SPS to file a compliance filing calculating its refund obligation within 30 days of the date of the Order and implement the instructions in the order in calculating its FCAC charges going forward from that date. While the order is subject to interpretation with respect to aspects of the calculation of the refund obligation, SPS does not expect its refund obligation to its full requirements customers from Jan. 1, 2005 through March 31, 2008, to exceed $11 million. PNM has filed a separate complaint that any refund obligation to PNM will be determined in that docket. SPS is reviewing the Order and has not yet determined whether to seek rehearing.

The FERC also ruled on two other FCA issues. First, it required that wind contracts be evaluated on an individual contract basis rather than in aggregate. Second, the FERC determined that an after the fact screen should be applied to all Qualifying Facility (QF) purchases to determine if they are economic. While this review will require additional effort, it is not expected that this will result in additional refunds as all of the individual wind contracts as well as the QF purchases are typically economic when compared to market energy prices.

As of June 30, 2008, SPS has accrued an amount sufficient to cover the estimated refund obligation. On July 21, 2008, SPS submitted it compliance report to the FERC. In the report, SPS has calculated the base rate refund for the 18-month period to be equal to $6.1 million and the fuel refund to be equal to $4.4 million. Once the final refund amounts are approved by the FERC, interest will be added to the refund due the full requirements customers.

Wholesale 2005 Power Base Rate Application In December 2005, SPS filed for a $2.5 million increase in wholesale power rates to certain electric cooperatives. In January 2006, the FERC conditionally accepted the proposed rates for filing and the $2.5 million power rate increase became effective on July 1, 2006, subject to refund. The FERC also set the rate increase request for hearing and settlement judge procedures. In September 2006, offers of settlement with respect to the five full-requirements customers and with respect to PNM were filed for approval. In September 2007, the FERC accepted the settlement with the full-requirements customers. The PNM settlement is still pending before the FERC.

As noted, the Power Base Rate Application relating to Golden Spread was settled in conjunction with the Complaint Settlement discussed above. Therefore, SPS has settled with all parties in the Wholesale 2005 Power Base Rate Application, except for resolution with Golden Spread of the demand cost allocation methodology. SPS and the full-requirements customers have requested that the demand allocation issue be summarily ruled on in SPS favor. The judge has suspended the procedural schedule, pending a ruling on the motion for summary judgment.

SPS Formula Transmission Rate Case In December 2007, Xcel Energy submitted an application to implement a transmission formula rate for the SPS zone of the Xcel Energy Open Access Transmission Tariff (OATT). The changed rates will affect all wholesale transmission service customers using the SPS transmission network under either the SPP Regional OATT or the Xcel Energy OATT.

The proposed rates would be updated annually each July 1 based on SPS prior year actual costs and loads plus the revenue requirements associated with projected current year transmission plant additions. The proposed ROE is 12.7 percent, including a 50 basis point adder for SPS participation in the SPP RTO. The proposed rates would provide first year incremental annual transmission revenue for SPS of approximately $5.5 million.

In February 2008, the FERC accepted the proposed rates, suspending the effective date to July 6, 2008, and setting the rate filing for hearings and settlement procedures. The FERC granted a 50 basis point adder to the ROE that it will determine in this proceeding as a result of SPS participation in the SPP RTO. The SPS and SPP rate filings are now in settlement procedures. The ultimate outcome of the rate filings is not known at this time.

SPS 2008 Wholesale Rate Case On March 31, 2008, SPS filed a wholesale rate case seeking an annual revenue increase of $14.9 million or an overall 5.14 percent increase, based on 12.20 percent requested ROE. On April 21, 2008, a motion for dismissal and protest was filed by the four eastern New Mexico cooperatives.

In SPS answer to the motions to intervene and protest, SPS renewed its request for a nominal suspension of 60 days and asked the FERC to consider such a nominal suspension in exchange for SPS acceptance of two conditions. The first condition was that SPS would agree to a ROE of no more than 10.25 percent and second, SPS would agree to use a 12 CP demand allocator for the period the rates will be in effect. The SPS answer results in an annual revenue increase of $9.9 million or an overall 3.4 percent increase.

In May 2008, the FERC accepted the answer and ordered a nominal suspension for rates to go in to effect as of the date of commercial service of the LPP plant. The LPP plant is expected to be in commercial operation in late summer of 2008.

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7. Commitments and Contingent Liabilities

Except to the extent noted below, the circumstances set forth in Notes 14, 15 and 16 to the consolidated financial statements included in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2007, and Note 6 to the consolidated financial statements in this Quarterly Report on Form 10-Q appropriately represent, in all material respects, the current status of other 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 unresolved contingencies that are material to Xcel Energy s financial position.

Operating Leases During the second quarter of 2008, three purchased power agreements were commenced, one for NSP-MN and two for PSCo, that are being accounted for as operating leases in accordance with EITF No. 01-8, *Determining Whether an Arrangement Contains a Lease,* and SFAS No. 13, *Accounting for Leases*. These agreements require capacity payments of $26.5 million, $38.3 million, $38.7 million, $39.1 million, $39.6 million and $631.8 million for 2008, 2009, 2010, 2011, 2012 and thereafter, respectively.

Environmental Contingencies

Xcel Energy 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 (PRP) and through the rate regulatory process. New and changing federal and state environmental mandates can also create added financial liabilities for Xcel Energy 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 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 subsidiaries, predecessors, or other entities; and

third-party sites, such as landfills, to which Xcel Energy is alleged to be a PRP that sent hazardous materials and wastes. At June 30, 2008, the liability for the cost of remediating these sites was estimated to be $69.8 million, of which $2.2 million was considered to be a current liability.

Manufactured Gas Plant Sites

Ashland Manufactured Gas Plant Site NSP-Wisconsin was 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 Chequemegon Bay adjoining the park.

In September 2002, the Ashland site was placed on the National Priorities List. A final determination of the scope and cost of the remediation of the Ashland site is not currently expected until early 2009. NSP-Wisconsin continues to work with the Wisconsin Department of Natural Resources (WDNR) to access state and federal funds to apply to the ultimate remediation cost of the entire site.

In October 2004, the WDNR filed a lawsuit in Wisconsin state court for reimbursement of past oversight costs incurred at the Ashland site between 1994 and March 2003 in the approximate amount of $1.4 million. The lawsuit has been stayed. NSP-Wisconsin has recorded an estimate of its potential liability. All costs paid to the WDNR are expected to be recoverable in rates.

In November 2005, the Environmental Protection Agency (EPA) Superfund Innovative Technology Evaluation Program (SITE) Program accepted the Ashland site into its program. As part of the SITE program, NSP-Wisconsin proposed and the EPA accepted a site demonstration of an in situ, chemical oxidation technique to treat upland ground water and contaminated soil. The fieldwork for the demonstration study was completed in February 2007. In 2007, NSP-Wisconsin spent $1.5 million in the development of the work plan, the operation of the existing interim response action and other matters related to the site. In June 2007, the EPA modified its remedial investigation report to establish final remedial action objectives (RAOs) and preliminary remediation goals (PRGs) for the Ashland site. The RAOs and PRGs could potentially impact the development and evaluation of remedial options for ultimate site cleanup. In October 2007, the EPA approved the series of reports included in the remedial investigation report. The draft feasibility study, which develops and assesses the alternatives for cleaning up the site, was prepared by NSP-Wisconsin and was submitted to the EPA in October 2007. The EPA commented on the draft feasibility study in February 2008, and a revised feasibility study addressing EPA s concerns was submitted in May 2008. The estimated remediation costs for the site range between $49.7 million and $137.5 million, including costs set forth in the revised feasibility study, as well as estimates for WDNR past oversight costs, outside legal and consultant costs and work plan costs.

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In addition to potential liability for remediation, NSP-Wisconsin may also have liability for natural resource damages (NRD) at the Ashland site. NSP-Wisconsin has indicated to the relevant natural resource trustees its interest in engaging in discussions concerning the assessment of natural resources injuries and in proposing various restoration projects in an effort to fully and finally resolve all NRD claims. NSP-Wisconsin is not able to estimate its potential exposure for NRD at the site, but has recorded an estimate of its potential liability based upon the minimum of its estimated range of potential exposure.

Until the EPA and the WDNR select a remediation strategy for the entire site and determine NSP-Wisconsin s level of responsibility, NSP-Wisconsin s liability for the actual cost of remediating the Ashland site and the time frame over which the amounts may be paid out are not determinable. However, as of June 30, 2008, NSP-Wisconsin has recorded a liability of $65.9 million based on management s best estimate of remediation 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 MGP-related 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 for other Wisconsin utilities. External MGP remediation costs are subject to deferral in the Wisconsin retail jurisdiction and are reviewed for prudence as part of the Wisconsin biennial retail rate case process.

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.

Fort Collins Manufactured Gas Plant Site Prior to 1926, the Poudre Valley Gas Co. operated an MGP in Fort Collins, Colo., not far from the Cache la Poudre River. In 1926, after acquiring the assets of the Poudre Valley Gas Co., PSCo shut down the MGP and has subsequently sold most of the property. In 2002, an oily substance similar to MGP byproducts was discovered in the Cache la Poudre River. In November 2004, PSCo entered into an agreement with the EPA, the city of Fort Collins and Schrader Oil Co. (Schrader) under which PSCo performed remediation and monitoring work. PSCo has substantially completed work at the site, with the exception of ongoing maintenance and monitoring.

In November 2006, PSCo filed a natural gas rate case with the CPUC requesting recovery of additional clean-up costs at the Fort Collins MGP site spent through September 2006, plus unrecovered amounts previously authorized from the last rate case, which amounted to $10.8 million to be amortized over four years. In June 2007, PSCo entered into a settlement agreement that included recovery of the full $10.8 million, but with a five-year amortization period. The CPUC approved the agreement on June 18, 2007. The total amount to be recovered from customers is $13.1 million. Estimated future project costs, based upon an assumed 30-year system operating life, including EPA oversight costs, are approximately $3.9 million.

In April 2005, PSCo brought a contribution action against Schrader and related parties alleging Schrader released hazardous substances into the environment and these releases caused MGP byproducts to migrate to the Cache la Poudre River, thereby substantially increasing the scope and cost of remediation. PSCo requested damages, including a portion of the costs PSCo incurred to investigate and remove contaminated sediments from the Cache la Poudre River. In December 2005, the court denied Schrader s request to dismiss the PSCo suit. Schrader thereafter filed a response to the PSCo complaint and a counterclaim against PSCo for its response costs under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA) and under the Resource Conservation and Recovery Act (RCRA). Schrader alleged as part of its counterclaim an imminent and substantial endangerment of its property as defined by RCRA. PSCo filed a motion for partial summary judgment to dismiss Schrader s RCRA claim. In October 2007, the court granted PSCo s motion for partial summary judgment and dismissed

Schrader s RCRA claim. Schrader also filed a motion for summary judgment seeking to dismiss PSCo s CERCLA claim, which was denied by the court in April 2008. The case is currently scheduled for a January 2009 trial. Any costs recovered from Schrader are expected to be credited to ratepayers.

Third Party and Other Environmental Site Remediation

Asbestos Removal Some of our facilities contain asbestos. Most asbestos will remain undisturbed until the facilities that contain it are demolished or renovated. Xcel Energy has recorded an estimate for final removal of the asbestos as an asset retirement obligation.

See additional discussion of asset retirement obligations in Note 15 of the Xcel Energy Annual Report on Form 10-K for the year ended Dec. 31, 2007. 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 immaterial and is recorded as incurred as operating expenses for maintenance projects, capital expenditures for construction projects or removal costs for demolition projects.

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Other Environmental Requirements

Clean Air Interstate Rule In March 2005, the EPA issued the Clean Air Interstate Rule (CAIR) to further regulate SO2 and NOx emissions. The objective of CAIR is to cap emissions of SO2 and NOx in the eastern United States, including Minnesota, Texas and Wisconsin, which are within Xcel Energy s service territory. Xcel Energy generating facilities in other states are not affected. CAIR addresses the transportation of fine particulates, ozone and emission precursors to nonattainment downwind states. CAIR has a two-phase compliance schedule, beginning in 2009 for NOx and 2010 for SO2, with a final compliance deadline in 2015 for both emissions. Under CAIR, each affected state will be allocated an emissions budget for SO2 and NOx that will result in significant emission reductions. It will be based on stringent emission controls and forms the basis for a cap-and-trade program. State emission budgets or caps decline over time. States can choose to implement an emissions reduction program based on the EPA s proposed model program, or they can propose another method, which the EPA would need to approve.

In July 2005, SPS, the City of Amarillo, Texas and Occidental Permian LTD filed a lawsuit against the EPA and a request for reconsideration with the agency to exclude West Texas from the CAIR. El Paso Electric Co. joined in the request for reconsideration. Xcel Energy and SPS advocated that West Texas should be excluded from CAIR because it does not contribute significantly to nonattainment with the fine particulate matter standards in any downwind jurisdiction.

In March 2006, the EPA denied the petition for reconsideration and in June 2006, Xcel Energy and the other parties filed a petition for review of the denial of the petition for reconsideration, as well as a petition for review of the Federal Implementation Plan, with the D.C. Circuit Court of Appeals. On July 11, 2008, the court issued an opinion upholding the EPA s decision to include West Texas in the CAIR region, but vacating CAIR in its entirety on several other grounds and remanding the rule to the EPA. Xcel Energy is currently analyzing the opinion and its implications on its consolidated financial statements, and will update the following discussion of CAIR pending further review.

Under CAIR s cap-and-trade structure, SPS can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. The remaining capital investments for NOx controls in the SPS region are estimated at $12 million. Annual purchases of SO2 allowances are estimated in the range of $5 million to $25 million each year, beginning in 2012, for phase I, based on allowance costs and fuel quality as of March 2007.

In addition, Minnesota and Wisconsin will be included in CAIR, and Xcel Energy has generating facilities in these states that will be impacted. The preliminary estimate of capital expenditures associated with compliance with CAIR in Minnesota and Wisconsin is $41.4 million. Purchases of NOx allowances for NSP-Minnesota are estimated at $2.3 million in 2009 with no NOx allowance needs in 2010. For NSP-Wisconsin, purchases of CAIR NOx allowances are estimated at $1.6 million in 2009 and $1.7 million in 2010.

Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers in rates. Xcel Energy will continue to review these cost projections in light of the court s opinion vacating CAIR.

Clean Air Mercury Rule In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR), which regulated mercury emissions from power plants. In February 2008, the D.C. Circuit Court of Appeals vacated CAMR, which impacts federal CAMR requirements, but not necessarily state-only mercury legislation and rules. Costs to comply with the Minnesota Mercury Emissions Reduction Act of 2006 are discussed below.

In Colorado, the Air Quality Control Commission passed a mercury rule, which requires mercury emission controls capable of achieving 80 percent capture to be installed at the Pawnee Generating Station by 2012 and all other Colorado units by 2014. Xcel Energy is in the process of installing mercury monitors on six Colorado units at an estimated aggregate cost of approximately $2.3 million. Xcel Energy is evaluating the emission controls required to meet the state rule and is currently unable to provide a capital cost estimate.

In the SPS region, the Texas Commission on Environmental Quality (TCEQ) adopted by reference the EPA model program. Given the many uncertainties created by the decision of the D.C. Circuit Court of Appeals to vacate CAMR, it is not possible at this time to provide an accurate summary of applicable federal mercury requirements or cost estimates.

Minnesota Mercury Legislation In May 2006, the Minnesota legislature enacted the Mercury Emissions Reduction Act of 2006 (Act) providing a process for plans, implementation and cost recovery for utility efforts to curb mercury emissions at certain power plants. For Xcel Energy, the Act covers units at the A. S. King and Sherco generating facilities. Under the Act, Xcel Energy is operating and maintaining continuous mercury emission monitoring systems. The information obtained will be used to establish a baseline from which to measure mercury emission reductions. Mercury emission reduction plans were required to be filed by utilities by Dec. 31, 2007 (dry scrubbed units) and Dec. 31, 2009 (wet scrubbed units) that propose to implement technologies most likely to

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reduce emissions by 90 percent. Implementation would occur by Dec. 31, 2009 for one of the dry scrubbed units, Dec. 31, 2010 for the remaining dry scrubbed unit and Dec. 31, 2014 for wet scrubbed units. The cost of controls will be determined as part of the engineering analysis portion of the mercury reduction plans and is currently estimated to range from $26.5 to $854.5 million for the mercury control and continuous monitoring equipment for Sherco units 1, 2 and 3 and for A. S. King, with increased operating and maintenance expenses estimated to range from approximately $24.7 to $77.2 million. The lower values include costs to achieve a 50 percent mercury reduction for Sherco units 1 and 2 and a 90 percent mercury reduction for Sherco unit 3 and A. S. King. The higher values include costs to achieve a 90 percent mercury reduction for all Sherco units, as well as for A. S. King. Utilities subject to the Act may also submit plans to address non-mercury pollutants subject to federal and state statutes and regulations, which became effective after Dec. 31, 2004. Cost recovery provisions of the Act also apply to these other environmental initiatives. In September 2006, NSP-Minnesota filed a request with the MPUC for recovery of up to $6.3 million of certain environmental improvement costs that are expected to be recoverable under the Act. In January 2007, the MPUC approved this request to defer these costs as a regulatory asset with a cap of $6.3 million. To date, NSP-Minnesota has spent approximately $1.4 million on mercury monitoring implementation.

Voluntary Capacity Upgrade and Emissions Reduction Filing In December 2007, NSP-Minnesota filed a plan with the Minnesota Pollution Control Agency (MPCA) and MPUC for reducing mercury emissions by up to 90 percent at the Sherco unit 3 and A. S. King plants. Estimated project costs amount to approximately $9.1 million. At the same time, NSP-Minnesota submitted a revised filing to the MPUC for a major emissions reduction project at Sherco units 1 and 2 to reduce emissions and expand capacity. The revised filing has estimated project costs of approximately $1.1 billion and encompasses the higher value mercury control costs discussed above in the Minnesota Mercury Legislation section. The filing also contains alternatives for the MPUC to consider to add additional capacity and to achieve even lower emissions. If selected, these alternatives could range from $90.8 to $330.8 million in addition to the $1.1 billion proposal. NSP-Minnesota s investments are subject to MPUC approval of a cost recovery mechanism. The MPCA has issued its assessment that the Sherco unit 3 and A. S. King plans are appropriate; its review of the Sherco units 1 and 2 plans are pending.

Regional Haze Rules In June 2005, the EPA finalized amendments to the July 1999 regional haze rules. These amendments apply to the provisions of the regional haze rule that require emission controls, known as best available retrofit technology (BART), for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. Xcel Energy generating facilities in several states will be subject to BART requirements.

The EPA required states to develop implementation plans to comply with BART by December 2007. States are required to identify the facilities that will have to reduce SO2, NOx, and particulate matter emissions under BART and then set BART emissions limits for those facilities. In May 2006, the Colorado Air Quality Control Commission (AQCC) promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART or an approved BART alternative to make reasonable progress toward meeting the national visibility goal. PSCo estimates that implementation of the BART alternatives will cost approximately $201 million in capital costs, which includes approximately $59 million in environmental upgrades for the existing Comanche Station project, which are included in the capital budget. PSCo expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2011 and 2014. On June 4, 2007, the Colorado Air Pollution Control Division (CAPCD) approved PSCo s BART analysis and obtained public comment on its BART determination and PSCo s BART permits. The AQCC approved the CAPCD s BART determination for PSCo during a public hearing in December 2007. CAPCD s BART determinations and corresponding provisions of the regional haze state implementation plan will be submitted to the EPA for approval in 2008. In addition, in early 2008, the CAPCD initiated a stakeholder process to establish reasonable progress goals for Colorado s Class I areas. To meet these goals, more controls may be required from certain sources, which may or may not include those sources previously controlled under BART. The reasonable progress stakeholder process has been placed on hold by the CAPCD due to limited resources and will resume in early 2009.

NSP-Minnesota submitted its BART alternatives analysis for Sherco units 1 and 2 in October 2006. The MPCA reviewed the BART analyses for all units in Minnesota and determined that overall, compliance with CAIR is better than BART. At this time, the MPCA is not requiring any BART specific controls that go beyond controls required for CAIR compliance. In light of the D.C. Circuit Court of Appeals decision vacating

CAIR, the MPCA is currently reviewing this determination.

Federal Clean Water Act The federal Clean Water Act requires the EPA to regulate cooling water intake structures to assure that these structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. In July 2004, the EPA published phase II of the rule, which applies to existing cooling water intakes at steam-electric power plants. Several lawsuits were filed against the EPA in the United States Court of Appeals for the Second Circuit challenging the phase II rulemaking. In January 2007, the court issued its decision and remanded virtually every aspect of the rule to the EPA for reconsideration. In June 2007, the EPA suspended the deadlines and referred any implementation to each state s best professional judgment until the EPA is able to fully respond to the court-ordered remand. As a result, the rule s compliance requirements and associated deadlines are currently unknown. It is not possible to provide an accurate estimate of the overall cost of this rulemaking at this time due to the many uncertainties involved. In April 2008, the U.S. Supreme Court granted limited review of the Second Circuit s opinion to determine whether the EPA has the authority to consider costs and benefits in assessing BTA. A decision is not expected until 2009.

Maddox Station Groundwater The New Mexico Environment Department (NMED) is requiring wastewater activity at Maddox Station to be permitted. SPS is engineering wastewater management facilities and submitted the permit application in July 2008. The estimated cost of the project is $1.8 million with an anticipated completion date in the third quarter of 2009.

New York Office of the Attorney General Subpoena In September 2007, the Office of the New York Attorney General (NYAG) issued a subpoena pursuant to the Martin Act, a New York statute, to Xcel Energy. The subpoena seeks information and documents related to Xcel Energy s analysis of risks posed by climate change and possible climate legislation and its disclosures of such risks to investors. In a letter accompanying the subpoena, the NYAG asserts that the increase in carbon dioxide (CO2) emissions upon completion of Comanche 3 (a coal-fired unit), in combination with Xcel Energy s other coal-fired plants, will subject Xcel to increased financial, regulatory and litigation risks which need to be disclosed to shareholders. Xcel Energy believes it has fully disclosed these risks, to the extent they can be ascertained, and such disclosures belie the concerns expressed by the NYAG. Xcel Energy and the NYAG have reached a settlement in principle regarding this matter and are in the process of finalizing the settlement document.

PSCo Notice of Violation In July 2002, PSCo received a Notice of Violation (NOV) from the EPA alleging violations of the New Source Review (NSR) requirements of the Clean Air Act (CAA) at the Comanche and Pawnee plants 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. It 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.

Cherokee Station Alleged Clean Air Act Violations In January 2008, Xcel Energy received a notice letter from Rocky Mountain Clean Air Action stating that the group intends to sue Xcel Energy for alleged CAA violations at Cherokee Station. The group claims that Cherokee Station s opacity emissions have exceeded allowable limits over the past five years and that its opacity monitors exceeded downtime limits. Xcel Energy disputes these claims and believes they are without merit. The CAA requires notice be given 60 days prior to filing a lawsuit. If the group does in fact file its threatened lawsuit, Xcel Energy will vigorously defend itself against these claims.

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 of them. The ultimate outcome of these matters cannot presently be determined. Accordingly, the ultimate resolution of these matters could have a material adverse effect on Xcel Energy s financial position and results of operations.

Gas Trading Litigation

e prime was a wholly owned subsidiary of Xcel Energy. Among other things, e prime was in the business of natural gas trading and marketing. e prime has not engaged in natural gas trading or marketing activities since 2003. Twelve lawsuits have been commenced against e prime and Xcel Energy (and NSP-Wisconsin in one instance), alleging fraud and anticompetitive activities in conspiring to restrain the trade of natural gas and manipulate natural gas prices. Xcel Energy, e prime, and NSP-Wisconsin deny these allegations and will vigorously defend against these lawsuits, including seeking dismissal and summary judgment.

The initial gas-trading lawsuit, a purported class action brought by wholesale natural gas purchasers, was filed in November 2003 in the United States District Court in the Eastern District of California. e prime is one of several defendants named in the complaint. This case is captioned *Texas-Ohio Energy vs. CenterPoint Energy.* The other eleven cases arising out of the same or similar set of facts are captioned *Fairhaven Power Company vs. EnCana Corporation et al; Ableman Art Glass vs. EnCana Corporation et al; Utility Savings and Refund Services LLP vs. Reliant Energy Services Inc. et al; Sinclair Oil Corporation vs. e prime and Xcel Energy Inc.; Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al; Learjet, Inc. vs. e prime and Xcel Energy Inc et al; J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al; Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al; Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. et al; Arandell vs. e prime, Xcel Energy, NSP-Wisconsin et al and Hartford Regional Medical Center vs. e prime, Xcel Energy et al*. Many of these cases involve multiple defendants and have been transferred to Judge Phillip Pro of the United States District Court in Nevada, who is the judge assigned to the western area wholesale natural gas antitrust litigation. An exception is the *Missouri Public Service Commission* case, which was remanded to Missouri state court in November 2007.

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In April 2005, Judge Pro granted defendants motion to dismiss in *Texas Ohio Energy* based upon the filed rate doctrine. Based upon this same legal doctrine, Judge Pro subsequently granted defendants motion to dismiss in *Fairhaven Power Company, Ableman Art Glass and Utility Savings and Refund Services*. Plaintiffs subsequently appealed these dismissals to the Ninth Circuit Court of Appeals. In September 2007, the Ninth Circuit Court of Appeals reversed the dismissal and remanded the lawsuits to Judge Pro for consideration of whether any of plaintiffs claims are based upon retail rates not directly barred by the filed rate doctrine. e prime and some other defendants were dismissed from the *Breckenridge* lawsuit in February 2008, but Xcel Energy remains a defendant in that lawsuit and e prime Energy Marketing was added as a defendant in February 2008.

All of the gas trading lawsuits are in the early procedural stages of litigation. No trial dates have been set for any of these lawsuits; however, defendants motions to dismiss are pending in the *Missouri Public Service Commission* matter, and defendants summary judgment motions are pending in the *Learjet and J.P. Morgan* matters. An Early Neutral Evaluation session took place on July 16, 2008 on the *Abelman, Ever Bloom, Fairhaven, Texas-Ohio*, and *Utility Savings* cases, but a settlement was not reached. Trial for all cases venued in Nevada will likely be set for late 2009 or early 2010.

Cabin Creek Hydro Generating Station Accident

In October 2007, employees of RPI Coatings Inc. (RPI), a contractor retained by PSCo, were applying an epoxy coating to the inside of a penstock at PSCo s Cabin Creek Hydro Generating Station near Georgetown, Colo. This work was being performed as part of a corrosion prevention effort. A fire occurred inside the penstock, which is a 4,000-foot long, 12-foot wide pipe used to deliver water from a reservoir to the hydro facility. Four of the nine RPI employees working inside the penstock were positioned below the fire and were able to exit the pipe. The remaining five RPI employees were unable to exit the penstock. Rescue crews located the five employees a few hours later and confirmed their deaths. The accident was investigated by several state and federal agencies, including the federal Occupational Safety and Health Administration (OSHA) and the U.S. Chemical Safety Board and the Colorado Bureau of Investigations. In March 2008, OSHA proposed penalties totaling $189,900 for twenty-two serious violations and three willful violations arising out of the accident. In April 2008, Xcel Energy notified OSHA of its decision to contest all of the proposed citations. On May 28, 2008 the Secretary of Labor filed its complaint, and Xcel Energy subsequently filed its answer on June 17, 2008.

Environmental Litigation

Comanche 3 Permit Litigation In August 2005, Citizens for Clean Air and Water in Pueblo and Southern Colorado and Clean Energy Action filed a complaint in Colorado state court against the CAPCD alleging that the division improperly granted permits to PSCo under Colorado s Prevention of Significant Deterioration program for the construction and operation of Comanche 3. PSCo intervened in the case. In June 2006, the court ruled in PSCo s favor and held that the Comanche 3 permits had been properly granted and plaintiffs claims to the contrary were without merit. Plaintiffs appealed the decision. In February 2008, the Colorado Court of Appeals affirmed the state court s decision. Plaintiffs filed a petition with the Colorado Supreme Court seeking discretionary review of the appellate court decision. On June 30, 2008 the Colorado Supreme Court denied the petition.

Carbon Dioxide Emissions Lawsuit In July 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court in the Southern District of New York against five utilities, including Xcel Energy, to force reductions in CO_2 emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. The lawsuits allege that CO_2 emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. 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 October 2004, Xcel Energy and the other defendants filed a motion to dismiss the lawsuit. On Sept. 19, 2005, the court granted the motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the Second Circuit Court of Appeals. In June 2007 the Second Circuit Court of Appeals issued an order requesting the parties to file a letter brief regarding the impact of the United States Supreme Court s decision in Massachusetts v. EPA, 127 S.Ct. 1438 (April 2, 2007) on the issues raised by the parties on appeal. Among other things, in its decision in Massachusetts v. EPA, the United States Supreme Court held that CO_2 emissions are a pollutant subject to regulation by the EPA under the CAA. In response to the request of the Second Circuit Court of Appeals, in June 2007, the defendant utilities filed a letter brief stating the position that the United States Supreme Court s decision supports the arguments raised by the utilities on appeal. The Court of Appeals has taken the matter under advisement and is expected to issue an opinion in due course.

Comer vs. Xcel Energy Inc. et al. **In April 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court in the Southern District of Mississippi. The lawsuit names more than 45 oil, chemical and utility companies, including Xcel Energy, as defendants and alleges that defendants CO_2 emissions were a proximate and direct cause of the increase in the destructive capacity of Hurricane Katrina. Plaintiffs allege in support of their claim, several legal theories, including negligence and**

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public and private nuisance and seek damages related to the loss resulting from the hurricane. Xcel Energy believes this lawsuit is without merit and intends to vigorously defend itself against these claims. In August 2007, the court dismissed the lawsuit in its entirety against all defendants on constitutional grounds. In September 2007, plaintiffs filed a notice of appeal to the Fifth Circuit Court of Appeals. Oral arguments will be presented to the Court of Appeals on Aug. 6, 2008. It is uncertain when the Court will reach a decision.

Native Village of Kivalina vs. Xcel Energy Inc. et al. In February 2008, the City and Native Village of Kivalina, Alaska, filed a lawsuit in U.S. District Court for the Northern District of California against Xcel Energy and 23 other oil, gas and coal companies. The suit was brought on behalf of approximately 400 native Alaskans, the Inupiat Eskimo, who claim that Defendants emission of CO_2 and other greenhouse gases (GHG) contribute to global warming, which is harming their village. Plaintiffs claim that as a consequence, the entire village must be relocated at a cost of between $95 million and $400 million. Plaintiffs assert a nuisance claim under federal and state common law, as well as a claim asserting concert of action in which defendants are alleged to have engaged in tortious acts in concert with each other. Xcel Energy was not named in the civil conspiracy claim. Xcel Energy believes the claims asserted in this lawsuit are without merit and joined with other utility defendants in filing a motion to dismiss on June 30, 2008.

Employment, Tort and Commercial Litigation

Siewert vs. Xcel Energy In June 2004, plaintiffs, the owners and operators of a Minnesota dairy farm, brought an action in Minnesota state court against NSP-Minnesota alleging negligence in the handling, supplying, distributing and selling of electrical power systems; negligence in the construction and maintenance of distribution systems; and failure to warn or adequately test such systems. Plaintiffs allege decreased milk production, injury, and damage to a dairy herd as a result of stray voltage resulting from NSP-Minnesota s distribution system. Plaintiffs claim losses of approximately $7 million. NSP-Minnesota denies all allegations. After its motion to dismiss plaintiffs claims was denied, NSP-Minnesota filed a motion to certify questions for immediate appellate review. In October 2007, the court granted NSP- Minnesota s motion for certification, and the parties have filed briefs on appeal. Oral argument is set to take place on Sept. 11, 2008.

Qwest vs. Xcel Energy Inc. In June 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 Denver state court. In April 2006, Qwest filed a third party complaint against PSCo based on terms in a joint pole use agreement between Qwest and PSCo. Pursuant to this agreement, Qwest asserted PSCo had an affirmative duty to properly train and instruct its employees on pole safety, including testing the pole for soundness before climbing. In May 2006, PSCo filed a counterclaim against Qwest asserting Qwest had a duty to PSCo and an obligation under the contract to maintain its poles in a safe and serviceable condition. 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. On June 16, 2008, Qwest filed its appellate brief. After the matter is fully briefed by the parties, oral arguments will be scheduled.

Hoffman vs. Northern States Power Company In March 2006, a purported class action complaint was filed in Minnesota state court, on behalf of NSP-Minnesota s residential customers in Minnesota, North Dakota and South Dakota for alleged breach of a contractual obligation to maintain and inspect the points of connection between NSP-Minnesota s wires and customers homes within the meter box. Plaintiffs claim NSP-Minnesota s alleged breach results in an increased risk of fire and is in violation of tariffs on file with the MPUC. Plaintiffs seek injunctive relief and damages in an amount equal to the value of inspections plaintiffs claim NSP-Minnesota was required to perform over the past six years. In August 2006, NSP-Minnesota filed a motion for dismissal on the pleadings. In November 2006, the court issued an order denying NSP-Minnesota s motion, but later, pursuant to a motion by NSP-Minnesota, certified the issues raised in NSP-Minnesota s original motion for appeal as important and doubtful, and NSP-Minnesota filed an appeal with the Minnesota Court of Appeals. In January 2008, the Minnesota Court of Appeals determined the plaintiffs claims are barred by the filed rate doctrine and remanded the case to the district court for dismissal. Plaintiffs have petitioned the Minnesota Supreme Court for discretionary review, and in April 2008, the court granted the petition. The matter has been briefed by both parties. A date for oral argument has not yet been set.

MGP Insurance Coverage Litigation In October 2003, NSP-Wisconsin initiated discussions with its insurers regarding the availability of insurance coverage for costs associated with the remediation of four former MGP sites located in Ashland, Chippewa Falls, Eau Claire and LaCrosse, Wis. In lieu of participating in discussions, in October 2003, two of NSP-Wisconsin s insurers, St. Paul Fire & Marine Insurance Co. and St. Paul Mercury Insurance Co., commenced litigation against NSP-Wisconsin in Minnesota state district court. In November 2003, NSP-Wisconsin commenced suit in Wisconsin state circuit court against St. Paul Fire & Marine Insurance Co. and its other insurers. Subsequently, the Minnesota court enjoined NSP-Wisconsin from pursuing the Wisconsin litigation. The Wisconsin action remains in abeyance.

NSP-Wisconsin has reached settlements with 22 insurers, and these insurers have been dismissed from both the Minnesota and Wisconsin actions.

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In July 2007, the Minnesota state court issued a decision on allocation, reaffirming its prior rulings that Minnesota law on allocation should apply and ordering the dismissal, without prejudice, of eleven insurers whose coverage would not be triggered under such an allocation method. In September 2007, NSP-Wisconsin commenced an appeal in the Court of Appeals for Minnesota challenging the dismissal of these carriers. In November 2007, Ranger Insurance Company (Ranger) and TIG Insurance Company (TIG) filed a motion to dismiss NSP-Wisconsin s appeal, asserting that NSP-Wisconsin s failure to serve Continental Insurance Company, as successor in interest to certain policies issued by Harbor Insurance Company (Harbor), requires dismissal of NSP-Wisconsin s appeal. In February 2008, the Court of Appeals issued an order deferring a decision on the procedural motion filed by Harbor and TIG and referring the motion to the panel assigned to consider the merits of the appeal.

In April 2008, the Court of Appeals issued an order staying briefing and other appellate proceedings until further order of the court. The order was issued in response to NSP-Wisconsin s request that oral argument be deferred pending a decision by the Wisconsin Supreme Court in Plastics Engineering Co. vs. Liberty Mutual Insurance Co. In *Plastics Engineering Co.,* the Wisconsin Supreme Court will consider the method of allocation to be adopted in Wisconsin.

The PSCW has established a deferral process whereby clean-up costs associated with the remediation of former MGP sites are deferred and, if approved by the PSCW, recovered from ratepayers. Carrying charges associated with these clean-up costs are not subject to the deferral process and are not recoverable from ratepayers. Any insurance proceeds received by NSP-Wisconsin will be credited to ratepayers. None of the aforementioned lawsuit settlements are expected to have a material effect on Xcel Energy s consolidated financial statements.

Nuclear Waste Disposal Litigation In 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States 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 DOE and NSP-Minnesota. At trial, NSP-Minnesota claimed damages in excess of $100 million through Dec. 31, 2004. On Sept. 26, 2007, the court awarded NSP-Minnesota $116.5 million in damages. In December 2007, the court denied the DOE s motion for reconsideration. In February 2008, the DOE 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 April 2008, the DOE asked the appellate court to stay briefing until the appeals in several other nuclear waste cases have been decided, and the Court granted the request. Results of the judgment will not be recorded in earnings until the appeal and regulatory treatment and amounts to be shared with ratepayers have been resolved. Given the uncertainties, it is unclear as to how much, if any, of this judgment will ultimately have a net impact on earnings.

In August 2007, NSP-Minnesota filed a second complaint against the DOE in the 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 claims damages for the period Jan. 1, 2005 through June 30, 2007, which includes 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. The amount of such damages is expected to exceed $40 million. In January 2008, the court granted the DOE s motion to stay, subject to reevaluation after a decision has been filed in any one of the five pending appeals of nuclear waste storage cases.

Mallon vs. Xcel Energy Inc. In July 2007, Theodore Mallon and TransFinancial Corporation filed a declaratory judgment action against Xcel Energy in U. S. District Court in Colorado (Mallon Federal Action). In this lawsuit, plaintiffs seek a determination that Xcel Energy is not entitled to assert claims against plaintiffs related to the 1984 and 1985 sale of COLI to PSCo, a predecessor of Xcel Energy. In August 2007, Xcel Energy, PSCo and PSRI commenced a lawsuit in Colorado state court against Mallon and TransFinancial Corporation (Mallon State Action). In the Mallon State Action, Xcel Energy, PSCo and PSRI seek damages against Mallon and TransFinancial for, among other things, breach of contract and breach of fiduciary duties associated with the sale of the COLI policies. In August 2007, Xcel Energy also filed a motion to stay or, in the alternative, to dismiss the Mallon Federal Action. In September 2007, a motion to stay the Mallon State Court action was subsequently filed by Mallon and TransFinancial. In November 2007, the U.S. District Court in Colorado dismissed the complaint in the Mallon Federal Action and Mallon and TransFinancial subsequently withdrew their motion to stay the Mallon State Court Action. In May 2008, Xcel

Energy, PSCo and PSRI filed a second amended complaint that, among other things, adds Provident Life & Accident Insurance Company (Provident) as a defendant and asserts claims for breach of contract, unjust enrichment and fraudulent concealment against the insurance company. On June 23, 2008 Provident filed a motion to dismiss the complaint. Xcel Energy, PSCo and PSRI filed a brief in opposition to the motion on July 28, 2008. It is uncertain when the court will rule on this motion.

Fru-Con Construction Corporation vs. Utility Engineering (UE) et al. In March 2005, Fru-Con Construction Corporation (Fru-Con) commenced a lawsuit in U.S. District Court in the Eastern District of California against UE and the Sacramento Municipal Utility District (SMUD) for damages allegedly suffered during the construction of a natural gas-fired, combined-cycle power plant in Sacramento County. Fru-Con s complaint alleges that it entered into a contract with SMUD to construct the power plant and further alleges that UE was negligent with regard to the design services it furnished to SMUD. In August 2005, the court granted UE s motion

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to dismiss. Because SMUD remains a defendant in this action, the court has not entered a final judgment subject to an appeal with respect to its order to dismiss UE from the lawsuit. Because this lawsuit was commenced prior to the April 2005, closing of the sale of UE to Zachry, Xcel Energy is obligated to indemnify Zachry for damages related to this case up to $17.5 million. Pursuant to the terms of its professional liability policy, UE is insured up to $35 million.

Lamb County Electric Cooperative (LCEC) In 1995, LCEC petitioned the PUCT for a cease and desist order against SPS alleging SPS was unlawfully providing service to oil field customers in LCEC s certificated area. In May 2003, the PUCT issued an order denying LCEC s petition based on its determination that SPS in 1976 was granted a certificate to serve the disputed customers. LCEC appealed the decision to the District Court in Travis County, Texas. In August 2004, the court affirmed the decision of the PUCT. In September 2004, LCEC appealed the District Court s decision to the Court of Appeals for the Third Supreme Judicial District of the state of Texas. This appeal is currently pending.

In 1996, LCEC filed a suit for damages against SPS in the District Court in Lamb County, Texas, based on the same facts alleged in the petition for a cease and desist order at the PUCT. This suit has been dormant since it was filed, awaiting a final determination of the legality of SPS providing electric service to the disputed customers. The PUCT order from May 2003, which found SPS was legally serving the disputed customers, collaterally determines the issue of liability contrary to LCEC s position in the suit. An adverse ruling on the appeal of May 2003 PUCT order could result in a different determination of the legality of SPS service to the disputed customers.

8. Short-Term Borrowings and Other Financing Instruments

Short-Term Borrowings

Commercial Paper At June 30, 2008 and Dec. 31, 2007, Xcel Energy and its utility subsidiaries had commercial paper outstanding of approximately $672.9 million and $1,088.6 million, respectively. The weighted average interest rates at June 30, 2008 and Dec. 31, 2007 were 3.09 percent and 5.57 percent, respectively.

Guarantees

Xcel Energy provides guarantees and bond indemnities supporting certain subsidiaries. The guarantees issued by Xcel Energy guarantee payment or performance by its subsidiaries under specified agreements or transactions. As a result, Xcel Energy s exposure under the guarantees is based upon the net liability of the relevant subsidiary under the specified agreements or transactions. Most of the guarantees issued by Xcel Energy limit the exposure of Xcel Energy to a maximum amount stated in the guarantees. On June 30, 2008 and Dec. 31, 2007, Xcel Energy had issued guarantees of up to $74.9 million and $75.2 million, respectively, with $17.5 million of known exposure under these guarantees. In addition, Xcel Energy provides indemnity protection for bonds issued for itself and its subsidiaries. The total amount of bonds with this indemnity outstanding as of June 30, 2008 and Dec. 31, 2007, was approximately $31.9 million and $31.6 million, respectively. The total exposure of this indemnification cannot be determined at this time. Xcel Energy believes the exposure to be significantly less than the total amount of bonds outstanding.

9. Long-Term Borrowings and Other Financing Instruments

Junior Subordinated Notes

On Jan. 16, 2008, Xcel Energy issued $400 million of 7.6 percent junior subordinated notes (Junior Notes) due 2068. Due to certain features, rating agencies consider the Junior Notes to be hybrid debt instruments with a combination of debt and equity characteristics. The Junior Notes are not redeemable by Xcel Energy prior to 2013 without payment of a make-whole premium. The proceeds from this offering were used to repay short-term debt.

Interest payments on the Junior Notes may be deferred on one or more occasions for up to 10 consecutive years. If the interest payments on the Junior Notes are deferred, Xcel Energy may not declare or pay any dividends or distributions, or redeem, purchase, acquire, or make a liquidation payment on, any shares of its capital stock. Also during the deferral period, Xcel Energy may not make any principal or interest payments on, or repay, purchase or redeem any of its debt securities that are equal in right of payment with, or subordinated to, the Junior Notes. Xcel Energy also may not make payments on any guarantees equal in right of payment with, or subordinated to, the Junior Notes.

In connection with the completion of this offering, Xcel Energy entered into a Replacement Capital Covenant (RCC) for the benefit of persons that buy, hold, or sell a specified series of Xcel Energy long-term indebtedness ranking senior to the Junior Notes. Initially, Xcel Energy s 6.50 percent Senior Notes due July 1, 2036, was specified as such series of long-term debt. Under the terms of the RCC, Xcel Energy agrees not to redeem or repurchase all or part of the Junior Notes prior to 2038 unless qualifying securities are

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issued to non-affiliates in a replacement offering in the 180 days prior to the redemption or repurchase date. Qualifying securities include those that have equity-like characteristics that are the same as, or more equity-like than, the applicable characteristics of the Junior Notes at the time of redemption or repurchase.

First Mortgage Bonds

On March 18, 2008, NSP-Minnesota issued $500 million of 5.25 percent first mortgage bonds, series due March 1, 2018. NSP-Minnesota added the net proceeds from the sale of the first mortgage bonds to its general funds and applied a portion of the proceeds to the repayment of commercial paper and borrowings under the utility money pool arrangement.

10. Derivative Instruments

Xcel Energy and its subsidiaries use derivative instruments in connection with its utility commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. Qualifying hedging relationships are designated as either a hedge of a forecasted transaction or future cash flow (cash flow hedge), or a hedge of a recognized asset, liability or firm commitment (fair value hedge). The types of qualifying hedging transactions that Xcel Energy and its subsidiaries are currently engaged in are discussed below.

Cash Flow Hedges

Commodity Cash Flow Hedges Xcel Energy s utility subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices. These derivative instruments are designated as cash flow hedges for accounting purposes. At June 30, 2008, Xcel Energy had various commodity-related contracts designated as cash flow hedges extending through December 2009. The fair value of these cash flow hedges is recorded in other comprehensive income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place. This could include the purchase or sale of energy or energy-related products, the use of natural gas to generate electric energy or gas purchased for resale.

At June 30, 2008, Xcel Energy had $1.0 million in accumulated other comprehensive income related to commodity cash flow hedge contracts that is expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

Interest Rate Cash Flow Hedges Xcel Energy and its subsidiaries enter 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 a specific period. These derivative instruments are designated as cash flow hedges for accounting purposes.

At June 30, 2008, Xcel Energy had $0.2 million in net losses in accumulated other comprehensive income related to interest rate swaps/locks that is expected to be recognized in earnings during the next 12 months.

The following table shows the major components of the derivative instruments valuation in the consolidated balance sheets at June 30 and Dec. 31:

	June 30, 2008		Dec. 31, 2007	
(Thousands of Dollars)	**Derivative Instruments Valuation - Assets**	**Derivative Instruments Valuation - Liabilities**	**Derivative Instruments Valuation - Assets**	**Derivative Instruments Valuation - Liabilities**
Long term purchased power agreements	$ 400,734	$ 368,115	$ 426,774	$ 401,313
Electric and natural gas trading and hedging instruments	150,401	92,743	51,106	21,694
Interest rate hedging instruments		6,165	535	20,223
Total	$ 551,135	$ 467,023	$ 478,415	$ 443,230

In 2003, as a result of FASB Statement 133 Implementation Issue No. C20, 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 the first quarter of 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.

The impact of qualifying cash flow hedges on Xcel Energy s accumulated other comprehensive income, included in the consolidated statements of common stockholders equity and comprehensive income, is detailed in the following table:

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(Thousands of Dollars)	Three months ended June 30, 2008		2007	
Accumulated other comprehensive (loss) income related to cash flow hedges at Apr. 1	$	(7,042)	$	1,396
After-tax net unrealized gains related to derivatives accounted for as hedges		843		7,133
After-tax net realized losses (gains) on derivative transactions reclassified into earnings		65		(199)
Accumulated other comprehensive (loss) income related to cash flow hedges at June 30	$	(6,134)	$	8,330

(Thousands of Dollars)	Six months ended June 30, 2008		2007	
Accumulated other comprehensive (loss) income related to cash flow hedges at Jan. 1	$	(1,416)	$	2,196
After-tax net unrealized (losses) gains related to derivatives accounted for as hedges		(4,758)		6,591
After-tax net realized losses (gains) on derivative transactions reclassified into earnings		40		(457)
Accumulated other comprehensive (loss) income related to cash flow hedges at June 30	$	(6,134)	$	8,330

Fair Value Hedges

Interest Rate Fair Value Hedges Xcel Energy enters into interest rate swap instruments that effectively hedge the fair value of fixed-rate debt. The fair market value of Xcel Energy s interest rate swap at June 30, 2008, was a liability of approximately $0.2 million. The interest rate swap expired on July 1, 2008.

11. Fair Value Measurements

Effective Jan. 1, 2008, Xcel Energy adopted SFAS No. 157 for recurring fair value measurements. SFAS No. 157 provides a single definition of fair value and requires enhanced disclosures about assets and liabilities measured at fair value. SFAS No. 157 establishes a hierarchal framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. The three levels defined by the SFAS No. 157 hierarchy and examples of each level are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reported date. The types of assets and liabilities included in Level 1 are highly liquid and actively traded instruments with quoted prices, such as equities listed by the New York Stock Exchange and commodity derivative contracts listed on the New York Mercantile Exchange.

Level 2 Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

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 with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value of financial transmission rights (FTR).

The following table presents, for each of these hierarchy levels, Xcel Energy s assets and liabilities that are measured at fair value on a recurring basis as of June 30, 2008:

(Thousands of Dollars)		**Level 1**		**Level 2**		**Level 3**		**Counterparty Netting (a)**		**Net Balance**
Assets										
Nuclear decommissioning fund	$	711,687	$	483,239	$	109,416	$		$	1,304,342
Commodity derivatives		980		45,962		103,842		(383)		150,401
Total	$	712,667	$	529,201	$	213,258	$	(383)	$	1,454,743
Liabilities										
Commodity derivatives	$		$	15,167	$	79,693	$	(2,117)	$	92,743
Interest rate derivatives				6,165						6,165
Total	$		$	21,332	$	79,693	$	(2,117)	$	98,908

(a) FASB Interpretation No. 39 *Offsetting of Amounts Relating to Certain Contracts*, as amended by FASB Staff Position FIN 39-1 *Amendment of FASB Interpretation No. 39*, 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

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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 tables present the changes in Level 3 recurring fair value measurements for the three and six months ended June 30, 2008:

(Thousands of Dollars)		Commodity Derivatives, Net		Nuclear Decommissioning Fund
Balance, April 1, 2008	$	15,355	$	97,232
Purchases, issuances, and settlements, net		(1,710)		13,901
Gains recognized in earnings		2,085		
Gains (losses) recognized as regulatory assets and liabilities		8,419		(1,717)
Balance, June 30, 2008	$	24,149	$	109,416

(Thousands of Dollars)		Commodity Derivatives, Net		Nuclear Decommissioning Fund
Balance, Jan. 1, 2008	$	19,466	$	108,656
Purchases, issuances, and settlements, net		(4,977)		3,650
Gains recognized in earnings		2,036		
Gains (losses) recognized as regulatory assets and liabilities		7,624		(2,890)
Balance, June 30, 2008	$	24,149	$	109,416

Gains on Level 3 commodity derivatives recognized in earnings for the three and six months ended June 30, 2008, include $1.9 million and $4.4 million, respectively, of net unrealized gains relating to commodity derivatives held at June 30, 2008. Realized and unrealized gains and losses on commodity trading activities are included in electric utility revenues. Realized and unrealized gains and losses on short-term wholesale activities reflect the impact of regulatory recovery and are deferred as regulatory assets and liabilities. Realized and unrealized gains and losses on nuclear decommissioning fund investments are deferred as a component of a nuclear decommissioning regulatory asset.

12. Detail of Interest and Other Income (Expense), Net

Interest and other income (expense), net of nonoperating expenses, for the three and six months ended June 30 consisted of the following:

	Three months ended June 30,				Six months ended June 30,			
(Thousands of Dollars)		2008		2007		2008		2007
Interest income	$	4,880	$	4,656	$	12,390	$	9,447
Equity income in unconsolidated affiliates		771		1,107		1,281		2,185
Other nonoperating income		1,825		611		3,340		1,231
Minority interest income		18		113		266		247
Insurance policy income (expense)		2,437		(7,122)		1,538		(12,897)
Other nonoperating expenses				(13)				(45)
Total interest and other income (expense), net	$	9,931	$	(648)	$	18,815	$	168

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13. Segment Information

Xcel Energy has the following reportable segments: regulated electric utility and regulated natural gas utility. Commodity trading operations performed by regulated operating companies are not a reportable segment. Commodity trading results are included in the regulated electric utility segment.

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Three months ended June 30, 2008					
Operating revenues from external customers	$ 2,154,383	$ 443,613	$ 17,519	$	$ 2,615,515
Intersegment revenues	296	1,997		(2,293)	
Total revenues	$ 2,154,679	$ 445,610	$ 17,519	$ (2,293)	$ 2,615,515
Income (loss) from continuing operations	$ 106,770	$ 11,872	$ 5,955	$ (19,124)	$ 105,473
Three months ended June 30, 2007					
Operating revenues from external customers	$ 1,919,695	$ 330,868	$ 16,729	$	$ 2,267,292
Intersegment revenues	186	5,780		(5,966)	
Total revenues	$ 1,919,881				