XCEL ENERGY INC
Form 10-Q
October 27, 2006

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 Sept. 30, 2006

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

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 or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x Accelerated Filer o Non-Accelerated Filer o

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 October 23, 2006
Common Stock, $2.50 par value	406,882,437 shares

TABLE OF CONTENTS

PART I   FINANCIAL INFORMATION
Item 1. Financial Statements (unaudited)
CONSOLIDATED STATEMENTS OF INCOME
CONSOLIDATED STATEMENTS OF CASH FLOWS
CONSOLIDATED BALANCE SHEETS
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS   EQUITY AND COMPREHENSIVE INCOME
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Item 2. MANAGEMENT   S DISCUSSION AND ANALYSIS
Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
Item 4. CONTROLS AND PROCEDURES
Part II   OTHER INFORMATION
Item 1. Legal Proceedings
Item 1A.Risk Factors
Item 5. Other Information
Item 6. Exhibits
SIGNATURES
Certifications Pursuant to Section 302
Certifications Pursuant to Section 906
Statement Pursuant to Private Litigation

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 Sept. 30, 2006	Three Months Ended Sept. 30, 2005	Nine Months Ended Sept. 30, 2006	Nine Months Ended Sept. 30, 2005
Operating revenues				
Electric utility	$ 2,159,844	$ 2,063,368	$ 5,792,287	$ 5,318,573
Natural gas utility	230,293	207,220	1,519,423	1,368,622
Nonregulated and other	21,454	15,535	61,858	53,344
Total operating revenues	2,411,591	2,286,123	7,373,568	6,740,539
Operating expenses				
Electric fuel and purchased power utility	1,160,896	1,121,154	3,106,804	2,794,791
Cost of natural gas sold and transported utility	136,795	127,493	1,156,042	1,028,317
Cost of sales nonregulated and other	4,096	3,745	16,763	17,163
Other operating and maintenance expenses utility	411,200	400,748	1,289,583	1,240,857
Other operating and maintenance expenses nonregulated	8,292	4,913	20,470	21,145
Depreciation and amortization	208,657	189,798	614,982	575,468
Taxes (other than income taxes)	71,552	73,547	221,413	220,634
Total operating expenses	2,001,488	1,921,398	6,426,057	5,898,375
Operating income	410,103	364,725	947,511	842,164
Interest and other income net of nonoperating expense (see Note 8)	2,149	1,930	2,686	4,365
Allowance for funds used during construction - equity	8,300	4,265	16,752	14,897
Interest charges and financing costs				
Interest charges includes other financing costs of $6,165, $6,426, $18,770 and $19,322, respectively	121,715	117,449	360,372	345,459
Allowance for funds used during construction - debt	(8,363)	(4,979)	(22,245)	(14,347)
Total interest charges and financing costs	113,352	112,470	338,127	331,112
Income from continuing operations before income taxes	307,200	258,450	628,822	530,314
Income taxes	83,025	60,633	156,899	130,241
Income from continuing operations	224,175	197,817	471,923	400,073
Income (loss) from discontinued operations net of tax (see Note 2)	287	(1,798)	2,112	830
Net income	224,462	196,019	474,035	400,903
Dividend requirements on preferred stock	1,060	1,060	3,180	3,180
Earnings available to common shareholders	$ 223,402	$ 194,959	$ 470,855	$ 397,723
Weighted average common shares outstanding (thousands)				
Basic	406,123	402,735	405,234	402,028
Diluted	430,000	426,085	429,095	425,368
Earnings per share basic				
Income from continuing operations	$ 0.55	$ 0.49	$ 1.16	$ 0.99

Discontinued operations				(0.01)				
Earnings per share basic	$	0.55	$	0.48	$	1.16	$	0.99
Earnings per share diluted								
Income from continuing operations	$	0.53	$	0.47	$	1.12	$	0.96
Discontinued operations								
Earnings per share diluted	$	0.53	$	0.47	$	1.12	$	0.96

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

	Nine Months Ended Sept. 30,	
(Thousands of Dollars)	**2006**	**2005**
Operating activities		
Net income	$ 474,035	$ 400,903
Remove income from discontinued operations	(2,112)	(830)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	643,520	582,126
Nuclear fuel amortization	35,359	32,436
Deferred income taxes	(105,793)	179,078
Amortization of investment tax credits	(7,354)	(8,715)
Allowance for equity funds used during construction	(16,752)	(14,897)
Undistributed equity in earnings of unconsolidated affiliates	(2,171)	(730)
Write down of assets		2,887
Unrealized (gain) loss on derivative instruments	(5,619)	6,868
Settlement of interest rate swap	4,328	
Change in accounts receivable	268,249	(103,273)
Change in inventories	(6,620)	(64,141)
Change in other current assets	431,895	24,143
Change in accounts payable	(341,207)	111,064
Change in other current liabilities	142,603	2,146
Change in other noncurrent assets	(94,619)	(16,505)
Change in other noncurrent liabilities	48,295	19,551
Operating cash flows provided by discontinued operations	129,744	157,872
Net cash provided by operating activities	1,595,781	1,309,983
Investing activities		
Utility capital/construction expenditures	(1,165,807)	(897,016)
Allowance for equity funds used during construction	16,752	14,897
Purchase of investments in external decommissioning fund	(699,593)	(94,452)
Proceeds from the sale of investments in external decommissioning fund	665,814	34,422
Nonregulated capital expenditures and asset acquisitions	(1,614)	(4,926)
Proceeds from sale of assets	24,670	11,228
Change in restricted cash	(3,085)	(13,906)
Other investments	9,697	9,339
Investing cash flows provided by discontinued operations	42,377	72,361
Net cash used in investing activities	(1,110,789)	(868,053)
Financing activities		
Short-term borrowings net	(396,120)	(4,300)
Proceeds from issuance of long-term debt	882,578	1,183,908
Repayment of long-term debt, including reacquisition premiums	(773,901)	(1,207,623)
Proceeds from issuance of common stock	7,747	6,763
Dividends paid	(267,228)	(255,413)
Financing cash flows used in discontinued operations		(200)
Net cash used in financing activities	(546,924)	(276,865)
Net (decrease) increase in cash and cash equivalents	(61,932)	165,065
Net increase (decrease) in cash and cash equivalents -discontinued operations	22,697	(2,750)
Cash and cash equivalents at beginning of year	72,196	23,361
Cash and cash equivalents at end of quarter	$ 32,961	$ 185,676
Supplemental disclosure of cash flow information:		
Cash paid for interest (net of amounts capitalized)	$ 307,922	$ 297,157
Cash paid for income taxes (net of refunds received)	$ (773)	$ 10,609

Supplemental disclosure of non-cash investing transactions:		
Property, plant and equipment additions in accounts payable	$ 43,068	$ 46,120
Supplemental disclosure of non-cash financing transactions:		
Issuance of common stock for reinvested dividends and 401(k) plans	$ 44,338	$ 37,197

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

(Thousands of Dollars)

	Sept. 30, 2006	Dec. 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 32,961	$ 72,196
Accounts receivable net of allowance for bad debts of $24,931 and $39,798, respectively	743,415	1,011,569
Accrued unbilled revenues	405,657	614,016
Materials and supplies inventories at average cost	164,226	159,560
Fuel inventory at average cost	86,248	64,987
Natural gas inventories at average cost	291,303	310,610
Recoverable purchased natural gas and electric energy costs	121,831	395,070
Derivative instruments valuation	209,247	213,138
Prepayments and other	189,239	99,904
Current assets held for sale and related to discontinued operations	298,169	200,811
Total current assets	2,542,296	3,141,861
Property, plant and equipment, at cost:		
Electric utility plant	19,214,265	18,870,516
Natural gas utility plant	2,825,073	2,779,043
Common utility and other	1,501,940	1,518,266
Construction work in progress	1,332,845	783,490
Total property, plant and equipment	24,874,123	23,951,315
Less accumulated depreciation	(9,703,821)	(9,357,414)
Nuclear fuel net of accumulated amortization: $1,225,745 and $1,190,386, respectively	135,390	102,409
Net property, plant and equipment	15,305,692	14,696,310
Other assets:		
Nuclear decommissioning fund and other investments	1,227,049	1,145,659
Regulatory assets	733,491	963,403
Prepaid pension asset	699,013	683,649
Derivative instruments valuation	451,109	451,937
Other	157,355	164,212
Noncurrent assets held for sale and related to discontinued operations	104,392	401,285
Total other assets	3,372,409	3,810,145
Total assets	$ 21,220,397	$ 21,648,316
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 160,956	$ 835,495
Short-term debt	350,000	746,120
Accounts payable	878,685	1,187,489
Taxes accrued	265,991	235,056
Dividends payable	91,513	87,788
Derivative instruments valuation	147,690	191,414
Accrued interest	136,603	116,423
Other	212,407	229,384
Current liabilities held for sale and related to discontinued operations	34,855	43,657
Total current liabilities	2,278,700	3,672,826
Deferred credits and other liabilities:		
Deferred income taxes	2,121,539	2,191,794
Deferred investment tax credits	124,046	131,400
Regulatory liabilities	1,581,313	1,710,820
Asset retirement obligations	1,349,112	1,292,006
Derivative instruments valuation	507,382	499,390

Benefit obligations and other	379,860	343,201
Customer advances	298,584	310,092
Minimum pension liability	88,280	88,280
Noncurrent liabilities held for sale and related to discontinued operations	8,909	6,936
Total deferred credits and other liabilities	6,459,025	6,573,919
Minority interest in subsidiaries	2,288	3,547
Commitments and contingent liabilities (see Note 5)		
Capitalization:		
Long-term debt	6,688,499	5,897,789
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: Sept. 30, 2006 406,524,931; Dec. 31, 2005 403,387,159	5,686,905	5,395,255
Total liabilities and equity	$ 21,220,397	$ 21,648,316

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

(UNAUDITED)

(Thousands)

	Common Stock Issued					
	Number of Shares	Par Value	Capital in Excess of Par Value	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
Three months ended Sept. 30, 2005 and 2006						
Balance at June 30, 2005	402,358	$ 1,005,894	$ 3,940,209	$ 429,518	$ (128,231)	$ 5,247,390
Net income				196,019		196,019
Net derivative instrument fair value changes during the period (see Note 7)					12,233	12,233
Unrealized gain - marketable securities					2	2
Comprehensive income for the period						208,254
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(86,618)		(86,618)
Issuances of common stock	524	1,310	8,757			10,067
Balance at Sept. 30, 2005	402,882	$ 1,007,204	$ 3,948,966	$ 537,859	$ (115,996)	$ 5,378,033
Balance at June 30, 2006	405,560	$ 1,013,901	$ 4,012,799	$ 632,263	$ (103,713)	$ 5,555,250
Net income				224,462		224,462
Minimum pension liability					(21)	(21)
Net derivative instrument fair value changes during the period (see Note 7)					(15,966)	(15,966)
Unrealized gain - marketable securities					15	15
Comprehensive income for the period						208,490
Dividends declared:						
Cumulative preferred stock				(1,060)		(1,060)
Common stock				(90,451)		(90,451)
Issuances of common stock	965	2,411	13,551			15,962
Share-based compensation (see Note 1)			(1,286)			(1,286)
Balance at Sept. 30, 2006	406,525	$ 1,016,312	$ 4,025,064	$ 765,214	$ (119,685)	$ 5,686,905

See Notes to Consolidated Financial Statements

XCEL ENERGY INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY

AND COMPREHENSIVE INCOME

(UNAUDITED)

(Thousands)

	Common Stock Issued		Capital in	Retained	Accumulated Other	Total
	Number of Shares	Par Value	Excess of Par Value	Earnings	Comprehensive Income (Loss)	Stockholders Equity
Nine months ended Sept. 30, 2005 and 2006						
Balance at Dec. 31, 2004	400,462	$ 1,001,155	$ 3,911,056	$ 396,641	$ (105,934)	$ 5,202,918
Net income				400,903		400,903
Minimum pension liability					220	220
Net derivative instrument fair value changes during the period (see Note 7)					(10,278)	(10,278)
Unrealized loss - marketable securities					(4)	(4)
Comprehensive income for the period						390,841
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(256,505)		(256,505)
Issuances of common stock	2,420	6,049	37,910			43,959
Balance at Sept. 30, 2005	402,882	$ 1,007,204	$ 3,948,966	$ 537,859	$ (115,996)	$ 5,378,033
Balance at Dec. 31, 2005	403,387	$ 1,008,468	$ 3,956,710	$ 562,138	$ (132,061)	$ 5,395,255
Net income				474,035		474,035
Minimum pension liability					(21)	(21)
Net derivative instrument fair value changes during the period (see Note 7)					12,354	12,354
Unrealized gain - marketable securities					43	43
Comprehensive income for the period						486,411
Dividends declared:						
Cumulative preferred stock				(3,180)		(3,180)
Common stock				(267,779)		(267,779)
Issuances of common stock	3,138	7,844	48,841			56,685
Share-based compensation (see Note 1)			19,513			19,513
Balance at Sept. 30, 2006	406,525	$ 1,016,312	$ 4,025,064	$ 765,214	$ (119,685)	$ 5,686,905

See Notes to Consolidated Financial Statements

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 Sept. 30, 2006, and Dec. 31, 2005; the results of its operations and changes in stockholders equity for the three and nine months ended Sept. 30, 2006 and 2005; and its cash flows for the nine months ended Sept. 30, 2006 and 2005. 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.

Except to the extent updated or described below, the footnotes set forth in the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005 appropriately represent, in all material respects, the current status of the footnotes and are incorporated herein by reference.

1. Significant Accounting Policies

Statement of Financial Accounting Standards (SFAS) No. 123 (Revised 2004) Share Based Payment (SFAS No. 123R) In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123R related to equity-based compensation. This statement replaces the original SFAS No. 123 Accounting for Stock-Based Compensation. Under SFAS No. 123R, companies are no longer allowed to account for their share-based payment awards using the intrinsic value method, which did not require any expense to be recorded on stock options granted with an equal to or greater than fair market value exercise price. Instead, equity-based compensation arrangements will be measured and recognized based on the grant-date fair value using an option-pricing model (such as Black-Scholes or Binomial) that considers at least six factors identified in SFAS No. 123R. An expense related to the difference between the grant-date fair value and the purchase price would be recognized over the vesting period of the options. Under previous guidance, companies were allowed to initially estimate forfeitures or recognize them as they actually occurred. SFAS No. 123R requires companies to estimate forfeitures on the date of grant and to adjust that estimate when information becomes available that suggests actual forfeitures will differ from previous estimates. Revisions to forfeiture estimates will be recorded as a cumulative effect of a change in accounting estimate in the period in which the revision occurs.

Previous accounting guidance allowed for compensation expense related to share-based payment awards to be reversed if the target was not met. However, under SFAS No. 123R, compensation expense for share-based payment awards that expire unexercised due to the company s failure to reach a certain target stock price cannot be reversed. Any accruals made for Xcel Energy s restricted stock unit award that was granted in 2004 and is based on a total shareholder return (TSR) cannot be reversed if the target is not met. Implementation of SFAS No. 123R is required for annual periods beginning after June 15, 2005. Xcel Energy adopted the provisions in the first quarter of 2006. Since stock options had vested and other awards were recorded at their fair values prior to implementation of SFAS No. 123R, implementation did not have a material impact on net income or earnings per share. Pro forma net income under SFAS No. 123R for the quarter and nine months ended Sept. 30, 2005 would not have been materially different than what was recorded.

Since the vesting of the 2004 restricted stock units is predicated on the achievement of a market condition, the achievement of a TSR, the fair value used to calculate the expense related to this award is based on the stock price on the date of grant adjusted for the uncertainty surrounding the achievement of the TSR. Since the vesting of the 2005 and 2006 restricted stock units is predicated on the achievement of a performance condition, the achievement of an earnings per share or environmental measures target, fair values used to calculate the expense on these plans are based on the stock price on the date of grant. The performance share plan awards have been historically settled partially in cash and therefore do not qualify as an equity award, but are accounted for as a liability award. As a liability award, the fair value on which expense is based is remeasured each period based on the current stock price, and final expense is based on the market value of the shares on the date the award is settled. Compensation expense related to share-based awards of approximately $13.8 million and $8.6 million was recorded in the third quarter of 2006 and 2005, respectively. Compensation expense related to share-based awards of approximately $34.7 million and $28.3 million was recorded in the first nine months of 2006 and 2005, respectively. As of Sept. 30, 2006, there was approximately $25.5 million of total unrecognized compensation cost related to non-vested share-based compensation awards. Total unrecognized compensation expense will be adjusted for future changes in estimated forfeitures. We expect to recognize that cost over a weighted-average period of 1.4 years. The amount of cash used to settle these awards was $11.3 million and $3.6 million for the first nine months of 2006 and 2005, respectively.

There have been no material changes to outstanding stock options in the third quarter of 2006.

See Note 9 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005 for a description of Xcel Energy s stock-based plans.

Metro Emissions Reduction Project (MERP) Accounting Allowance for funds used during construction (AFDC) is an amount capitalized as a part of construction costs representing the cost of financing the construction. Generally these costs are recovered from customers as the related property is depreciated. In December 2003, the Minnesota Public Utilities Commission (MPUC) voted to approve NSP-Minnesota s MERP proposal to convert two coal-fueled electric generating plants to natural gas, and to install advanced pollution control equipment at a third coal-fired plant. All three plants are located in the Minneapolis - St. Paul metropolitan area. These improvements are expected to significantly reduce air emissions from these facilities, while increasing the capacity at system peak by 300 MW. The projects are expected to come on line between 2007 and 2009, at a cumulative investment of approximately $1 billion. The MPUC has approved a more current recovery of the financing costs related to the MERP. The in-service plant costs, including the financing costs during construction, are recovered from customers through a MERP rider resulting in a lower recognition of AFDC.

FASB Interpretation No. 48 (FIN 48) In July 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. FIN 48 prescribes a comprehensive financial statement model of how a company should recognize, measure, present and disclose uncertain tax positions that the company has taken or expects to take in its income tax returns. FIN 48 requires that only income tax benefits that meet the more likely than not recognition threshold be recognized or continue to be recognized on its effective date. Initial derecognition amounts would be reported as a cumulative effect of a change in accounting principle.

FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. Xcel Energy is assessing the impact of the new guidance on all of its open tax positions.

Statement of Financial Accounting Standards No. 157 Fair Value Measurements (SFAS No. 157) In September 2006, the FASB issued SFAS No. 157, which enhances existing guidance for measuring assets and liabilities using fair value. SFAS No. 157 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, not an entity-specific measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Under SFAS No. 157, fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007. Xcel Energy is evaluating the impact of SFAS No. 157 on its financial condition and results of operations.

Statement of Financial Accounting Standards No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R) (SFAS No. 158) In September 2006, the FASB issued SFAS No. 158, which requires companies to fully recognize the funded status of each pension and other postretirement benefit plan as a liability or asset on their balance sheets with all unrecognized amounts to be recorded in other comprehensive income. Although Xcel Energy continues to evaluate the impact of the new pronouncement, preliminary estimates indicate that assets could be increased by approximately $453 million, other comprehensive income could be credited by approximately $103 million and liabilities could be increased by approximately $350 million. Xcel Energy is evaluating regulatory accounting treatment, which would allow recognition of this item as a regulatory asset rather than as a charge to accumulated other comprehensive income.

These estimates reflect the expected deferral of these amounts as regulatory assets or liabilities. The actual impact of the adoption of SFAS No. 158 could differ significantly from this estimate due to plan asset performance for the year and the discount rate in effect at the end of the year when the plans liabilities are measured. The implementation of SFAS No.158 will have no impact on net income. SFAS No. 158 is effective as of the end of the fiscal year ending after Dec. 15, 2006.

Reclassifications Certain items in the Consolidated Statements of Cash Flows related to nuclear decommissioning investments have been reclassified for the nine months ended Sept. 30, 2005 to conform to the 2006 gross investment activity presentation.

2. Discontinued Operations

A summary of the subsidiaries presented as discontinued operations is discussed below. Results of operations for divested businesses and the results of businesses held for sale are reported for all periods presented on a net basis as discontinued operations. In addition, the assets and liabilities of the businesses divested and held for sale in 2006 and 2005 have been reclassified to assets and liabilities held for sale in the accompanying Consolidated Balance Sheets.

Assets held for sale are valued on an asset-by-asset basis at the lower of carrying amount or fair value less costs to sell. In applying those provisions, management considered cash flow analyses, bids and offers related to those assets and businesses. Assets held for sale are not depreciated.

Regulated Utility Segments

During 2004, Xcel Energy reached an agreement to sell its regulated electric and natural gas subsidiary, Cheyenne Light, Fuel and Power Company (CLF&P). The sale was completed on Jan. 21, 2005.

Nonregulated Subsidiaries   All Other Segment

Utility Engineering In March 2005, Xcel Energy agreed to sell Utilty Engineering (UE) to Zachry Group, Inc. (Zachry). In April 2005, Zachry acquired all of the outstanding shares of UE. Xcel Energy recorded an insignificant loss in the first quarter of 2005 as a result of the transaction. In August 2005, Xcel Energy s board of directors approved management s plan to pursue the sale of Quixx, which was not included in the sale of UE to Zachry. In October 2006, a definitive agreement was reached for the sale of Quixx s interest in Borger Energy Associates and Quixx Power Services, Inc. to affiliates of Energy Investors Funds.

Seren On Sept. 27, 2004, Xcel Energy s board of directors approved management s plan to pursue the sale of Seren Innovations, Inc. (Seren), a wholly owned broadband subsidiary. On May 25, 2005, Xcel Energy reached an agreement to sell Seren s California assets to WaveDivision Holdings, LLC, which was completed in November 2005. In July 2005, Xcel Energy reached an agreement to sell Seren s Minnesota assets to Charter Communications, which was completed in January 2006.

NRG In December 2003, Xcel Energy divested its ownership interest in NRG Energy Inc. (NRG), a former independent power production subsidiary that had filed for bankruptcy protection in May 2003. Cash flows from receipt of NRG-related deferred income tax benefits occurred in 2004 and 2005. Approximately $261 million of remaining deferred tax benefits related to NRG are classified as a component of discontinued operations assets listed below.

Summarized Financial Results of Discontinued Operations

(Thousands of dollars)	**Utility Segments**	**All Other**	**Total**
Three months ended September 30, 2006			
Operating revenue	$	$ 1,374	$ 1,374
Operating expenses and other income		2,583	2,583
Pretax loss from operations of discontinued components		(1,209)	(1,209)
Income tax benefit	(1,068)	(428)	(1,496)
Net income (loss) from discontinued operations	$ 1,068	$ (781)	$ 287
Three months ended September 30, 2005			
Operating revenue and equity in project income	$	$ 15,183	$ 15,183
Operating expenses and other income		19,931	19,931
Pretax loss from operations of discontinued components		(4,748)	(4,748)
Income tax benefit		(2,950)	(2,950)
Net loss from operations of discontinued components	$	$ (1,798)	$ (1,798)

(Thousands of dollars)	**Utility Segments**	**All Other**	**Total**
Nine months ended September 30, 2006			

Operating revenue	$		$	6,212	$	6,212
Operating expenses and other income		(18)		8,748		8,730
Pretax income (loss) from operations of discontinued components		18		(2,536)		(2,518)
Income tax benefit		(2,233)		(2,397)		(4,630)
Net income (loss) from discontinued operations	$	2,251	$	(139)	$	2,112
Nine months ended September 30, 2005						
Operating revenue and equity in project income	$	6,579	$	49,498	$	56,077
Operating expenses and other income		6,131		50,488		56,619
Pretax income (loss) from operations of discontinued components		448		(990)		(542)
Income tax expense (benefit)		268		(1,640)		(1,372)
Net income from operations of discontinued components	$	180	$	650	$	830

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

(Thousands of dollars)		Sept. 30, 2006		Dec. 31, 2005
Cash	$	35,355	$	12,658
Trade receivables net		1,272		6,101
Deferred income tax benefits		176,518		157,812
Other current assets		85,024		24,240
Current assets held for sale and related to discontinued operations	$	298,169	$	200,811
Property, plant and equipment net	$	3,213	$	29,845
Deferred income tax benefits		93,841		352,171
Other noncurrent assets		7,338		19,269
Noncurrent assets held for sale and related to discontinued operations	$	104,392	$	401,285
Accounts payable trade	$	4,788	$	7,657
Other current liabilities		30,067		36,000
Current liabilities held for sale and related to discontinued operations	$	34,855	$	43,657
Other noncurrent liabilities	$	8,909	$	6,936
Noncurrent liabilities held for sale and related to discontinued operations	$	8,909	$	6,936

3. Tax Matters Corporate-Owned Life Insurance

Interest Expense Deductibility As previously disclosed, in April 2004, Xcel Energy filed a lawsuit against the U.S. government in the U.S. District Court for the District of Minnesota to establish its right to deduct the policy loan interest expense that had accrued during tax years 1993 and 1994 on policy loans related to its corporate-owned life insurance (COLI) policies that insured certain lives of employees of Public Service Company of Colorado (PSCo). These policies are owned and managed by PSR Investments, Inc. (PSRI), a wholly owned subsidiary of PSCo.

After Xcel Energy filed this suit, the Internal Revenue Service (IRS) sent its two statutory notices of deficiency of tax, penalty and interest for taxable years 1995 through 1999. Xcel Energy has filed U.S. Tax Court petitions challenging those notices. Xcel Energy anticipates the dispute relating to its claimed interest expense deductions for tax years 1993 and later will be resolved in the refund suit that is pending in the Minnesota federal district court and the Tax Court petitions will be held in abeyance pending the outcome of the refund litigation. In the third quarter of 2006, Xcel Energy also received a statutory notice of deficiency from the IRS for tax years 2000 through 2002 and timely filed a Tax Court petition challenging the denial of the COLI interest expense deductions for those years.

On Oct. 12, 2005, the district court denied Xcel Energy s motion for summary judgment on the grounds that there were disputed issues of material fact that required a trial for resolution. At the same time, the district court denied the government s motion for summary judgment that was based on its contention that PSCo had lacked an insurable interest in the lives of the employees insured under the COLI policies. However, the district court granted Xcel Energy s motion for partial summary judgment on the grounds that PSCo did have the requisite insurable interest.

On May 5, 2006, Xcel Energy filed a second motion for summary judgment. Oral arguments were presented on Aug. 8, 2006. A decision on this motion is pending. On Aug. 18, 2006, the U.S. government filed a second motion for summary judgment. Oral arguments were presented on Oct. 12, 2006, with the Court taking the matter under advisement. The district court has ordered the parties to be ready for trial by Jan. 2, 2007 in the event the motions are denied.

Xcel Energy believes that the tax deduction for interest expense on the COLI policy loans is in full compliance with the tax law. Accordingly, PSRI has not recorded any provision for income tax or related interest or penalties that may be imposed by the IRS, and has continued to take deductions for interest expense related to policy loans on its income tax returns for subsequent years. As discussed above, the litigation could require several years to reach final resolution. Defense of Xcel Energy s position may require significant cash outlays, which may or may not be recoverable in a court proceeding. Although the ultimate resolution of this matter is uncertain, it could have a material adverse effect on Xcel Energy s financial position, results of operations and cash flows.

Should the IRS ultimately prevail on this issue, tax and interest payable through Dec. 31, 2006, would reduce earnings by an estimated $419 million. In 2004, Xcel Energy received formal notification that the IRS will seek penalties. If penalties (plus associated interest) also are included, the total exposure through Dec. 31, 2006, is approximately $497 million. Xcel Energy annual earnings for 2006 would be reduced by approximately $44 million, after tax, or 10 cents per share, if COLI interest expense deductions were no longer available.

4. Rates and Regulation

Midwest Independent Transmission System Operator, Inc. (MISO) Operations Two of Xcel Energy s regulated utility subsidiaries, Northern States Power Company, a Minnesota corporation (NSP-Minnesota), and Northern States Power Company, a Wisconsin corporation (NSP-Wisconsin), are members of the MISO. The MISO is a regional transmission organization (RTO) that provides transmission tariff administration services for electric transmission systems, including those of NSP-Minnesota and NSP-Wisconsin. In 2002, NSP-Minnesota and NSP-Wisconsin received all required regulatory approvals to transfer functional control of their high voltage (100 kilovolts and greater) transmission systems to the MISO. The MISO exercises functional control over the operations of these facilities and the facilities of certain neighboring electric utilities. On April 1, 2005, MISO initiated a regional Day 2 wholesale energy market pursuant to its transmission and energy markets tariff.

MISO Cost Recovery

While the Day 2 market is designed to provide efficiencies through region-wide generation dispatch and increased reliability, there are costs associated with the Day 2 market. NSP-Minnesota and NSP-Wisconsin have attempted to address these costs with regulators in their respective jurisdictions as outlined below.

On Feb. 24, 2006, the MPUC ordered jurisdictional investor-owned utilities in the state, including NSP-Minnesota, to participate with the Minnesota Department of Commerce and other parties in a proceeding to evaluate suitability of recovery of some of the MISO Day 2 energy market costs in the variable fuel cost adjustment (FCA). The Minnesota utilities and other parties filed a joint report with the MPUC on June 22, 2006 recommending pass-through of MISO energy market costs in the FCA effective April 1, 2005, with the exception of two components which would be deferred and included in base retail electric rates in a future rate case upon a showing of MISO regional market benefits. The two components are MISO Schedule 16, which recoups MISO costs for administration of financial transmission rights (FTRs); and Schedule 17, which recoups the cost of MISO s market computer systems and staff. The MPUC has scheduled a technical conference for Oct. 31, 2006, and a decisional hearing for Nov. 9, 2006. Final action by the MPUC in response to the recommendations in this report is anticipated later in 2006. An adverse MPUC ruling on cost recovery of MISO Day 2 market costs could have a material financial impact on NSP-Minnesota.

In addition, on Sept. 1, 2006, NSP-Minnesota filed its annual electric automatic adjustment of charges (AAA) report to the MPUC. In the AAA report process, the MPUC and other state agencies will review NSP-Minnesota s recovery of fuel and purchased energy costs for the prior July to June period. For the period from July 2005 to June 2006, total MISO Day 2 market charges incurred for collection in the FCA were $257 million for the State of Minnesota jurisdiction. NSP-Minnesota expects the MPUC to issue its order in the 2006 AAA proceeding in 2007.

On June 16, 2006, the Public Service Commission of Wisconsin (PSCW) issued its written order regarding the joint request for escrow accounting treatment of MISO Day 2 costs made by NSP-Wisconsin and other Wisconsin utilities. The order confirms continued deferred accounting treatment for congestion costs, net line losses, and costs of acquiring FTRs not received in the MISO allocation process, as previously authorized by the PSCW. The order also clarifies that deferral is authorized for several additional MISO Day 2 cost and revenue types not explicitly addressed in the original PSCW order issued March 29, 2005. While deferral for most of the additional cost and revenue types was granted retroactive to April 1, 2005, a few types are deferrable beginning June 8, 2006.

On June 29, 2006, the PSCW opened a proceeding to address the proper amount of MISO Day 2 deferrals that the state s utilities should be allowed to recover and the proper method of rate recovery. At the July 13, 2006 pre-hearing conference, the administrative law judge (ALJ) narrowed the scope of the issues to the following:

The proper methodology for determining the recoverability of MISO Day 2 costs that have been deferred;

The amounts that have been deferred as of June 30, 2006, by each utility; and

The appropriateness of methods followed by the utilities.

NSP-Wisconsin filed initial testimony and exhibits in this proceeding on Sept. 1, 2006. In that testimony, NSP-Wisconsin detailed its calculation methodology and reported that, as of June 30, 2006, it had deferred approximately $6.2 million. The procedural schedule in the case requires PSCW staff and intervenor testimony to be filed by Dec. 8, 2006, and sets these issues for hearing on Jan. 31, 2007. NSP-Wisconsin currently anticipates that the ultimate decision on the amount of costs to be recovered in rates could be delayed until its 2008 general rate case.

As of Sept. 30, 2006 NSP-Wisconsin has deferred a total of approximately $7.0 million of MISO Day 2 costs.

Revenue Sufficiency Guarantee Charges

On April 25, 2006, the Federal Energy Regulatory Commission (FERC) issued an order determining that MISO had incorrectly applied its energy markets tariff regarding the application of the revenue sufficiency guarantee (RSG) charge to certain transactions. The FERC ordered MISO to resettle all affected transactions retroactive to April 1, 2005. The RSG charges are collected from certain MISO customers and paid to others. Based on the FERC order, Xcel Energy could be required to make net payments to MISO. The FERC issued an order granting rehearing in part on Oct. 26, 2006. The impact of the new order on Xcel Energy is under review; the order is also subject to potential additional rehearing requests and/or appeals. Xcel Energy reserved $5.9 million in response to the April 25, 2006, FERC order.

Ancillary Service Markets

MISO and its stakeholders are developing proposals to establish ancillary service markets within MISO s footprint. The proposals would increase market efficiency by providing a reduced allocation of generation contingency reserves for market participants and by creating economic market opportunities to obtain alternative sources of generating reserves. The proposed implementation of these market design improvements is scheduled for phase-in over the course of 2007, subject to project actions by MISO. In July 2006, the Midwest contingency reserve sharing group agreement (CRSGA) was executed by numerous parties.NSP-Minnesota and NSP-Wisconsin will participate through a collective of participants in the existing Mid-Continent Area Power Pool (MAPP) generation reserve sharing pool agreement, which would eventually be replaced by the MISO arrangement for contingency reserves. MISO filed the CRSGA for FERC approval in Aug. 2006, to be effective Jan. 1, 2007. The FERC approved the CRSGA on Oct. 24, 2006.

In addition, MISO expects to file in late Nov. 2006 for FERC approval to establish wholesale markets for contingency reserves and regulation services to be effective in October 2007. The ancillary services markets would be coordinated with the MISO Day 2 energy markets. MISO s costs to administer these markets would be collected through an increase in the Schedule 17 charge.

MISO Market Operations in Summer 2006

During July 2006, the MISO footprint experienced extremely hot weather, reaching a peak demand of more than 116,000 megawatts on July 31, 2006, after reaching a new peak of more than 113,000 megawatts on July 17, 2006. The MISO Day 2 market generally functioned well, and no significant outages occurred, but the peak demand was approximately equal to the peak demand MISO previously predicted for 2009, and locational marginal prices for energy reflected constrained regions that limited regional efficiency during some hours. The peak demands and regional constraints that cause congestion are expected to cause market participants and state regulatory commissions to review the need for additional generation, transmission and demand response programs.

FERC Transmission Rate Case (PSCo and SPS) On Sept. 2, 2004, Xcel Energy filed on behalf of PSCo and Southwestern Public Service Company (SPS) an application to increase wholesale transmission service and ancillary service rates within the Xcel Energy joint open access transmission tariff. PSCo and SPS requested an increase in annual transmission service and ancillary services revenues of $6.1 million. On Feb. 6, 2006, the parties in the proceeding submitted an uncontested offer of settlement that contains a $1.6 million rate increase for PSCo, a formula transmission service rate for PSCo, a 10.5 percent rate of return on common equity, and the phased inclusion of PSCo s 345 kilovolt tie line costs in wholesale transmission service rates; the settlement was expected to result in a $1.1 million stated rate increase for SPS effective June 2005, and SPS could file a further rate increase effective Oct. 1, 2006. On April 5, 2006, the FERC issued an order approving the uncontested settlement. PSCo placed the final rates in effect on June 1, 2005 and issued refunds of approximately $3.7 million.

Most transmission service users of the SPS system take service under the Southwest Power Pool (SPP) regional open access transmission tariff. On May 6, 2006, SPP submitted a compliance filing to the April 5, 2006, FERC order to include the SPS settlement rates in the SPP tariff effective retroactive to June 1, 2005. Certain customer parties protested aspects of the SPP filing as inconsistent with the Feb. 6, 2006 settlement. On Sept. 1, 2006, the FERC issued an order accepting the proposed SPP compliance point-to-point rates, but rejecting the network service tariffs. SPS filed a request for rehearing on Oct. 2, 2006. Separately, SPP filed a revised compliance filing on Oct. 2, 2006, which SPS has protested as inconsistent with the Feb. 6, 2006 settlement. Final FERC action is pending.

Other Regulatory Matters   NSP-Minnesota

Electric Rate Case In November 2005, NSP-Minnesota requested an electric rate increase of $168 million or 8.05 percent. This increase was based on a requested 11 percent return on common equity, a projected common equity to total capitalization ratio of 51.7 percent and a projected electric rate base of $3.2 billion. On Dec. 15, 2005, the MPUC authorized an interim rate increase of $147 million, subject to refund, which became effective on Jan. 1, 2006. In March 2006, the MPUC approved a new depreciation order, which lowered decommissioning accruals for 2006 from anticipated levels. Due to the seasonality of sales, the rate increase will not be recognized ratably throughout 2006.

On April 24, 2006, NSP-Minnesota reached a settlement agreement regarding the treatment of wholesale electric sales margins. The settlement is with five intervenor groups, including the Office of Attorney General and a large industrial customer group.

The settlement resolves recommendations of most parties regarding the treatment of wholesale electric sales margins. Significant components of the settlement agreement are as follows:

No credit to base electric rates for wholesale electric sales margins;

Wholesale electric sales margins derived from excess generation capacity will be flowed through the FCA as an offset to fuel and energy costs;

80 percent of wholesale margins derived from the sales from NSP-Minnesota s ancillary services obligations (e.g. spinning reserves) will be flowed through the FCA as an offset to fuel and energy costs and NSP-Minnesota will retain 20 percent; and

25 percent of proprietary margins, sales that do not arise from the use of NSP-Minnesota generating assets, will be flowed through the FCA as an offset to fuel and energy costs, and 75 percent will be retained by NSP-Minnesota.

The settlement agreement was considered in the MPUC s determination of NSP-Minnesota s overall requested increase.

On Sept. 1, 2006, the MPUC issued a written order granting a electric revenue increase of approximately $131 million for 2006 based on an authorized return on equity of 10.54 percent. The scheduled rate increase will be reduced in 2007 to $115 million to reflect the return of Flint Hills, a large industrial customer, to the NSP-Minnesota system. The MPUC rejected arguments by the Minnesota Office of the Attorney General regarding the recoverability of NSP-Minnesota s income tax benefits associated with NRG. The MPUC approved the wholesale margin settlement.

On Sept. 21, 2006, NSP-Minnesota filed a petition for reconsideration of the decision to reduce the rate increase to compensate for revenues associated with the return of Flint Hills and the recoverability of additional tree trimming expense. Other parties filed petitions regarding income tax benefits associated with NRG and a clarification of certain order language. The MPUC has scheduled a hearing on Nov. 2, 2006, to consider the petitions for reconsideration.

Excelsior Energy In December 2005, Excelsior Energy Inc., an independent energy developer, filed for approval of a proposed power purchase agreement with NSP-Minnesota for its proposed integrated gas combined cycle (IGCC) plant to be located in northern Minnesota. Excelsior Energy filed this petition pursuant to Minnesota law, which provides certain considerations for a qualifying Innovative Energy Project, subject to MPUC public interest determinations.

The MPUC referred this matter to a contested case hearing to develop the facts and issues that must be resolved to act on Excelsior s petition, including development of price information. The contested case proceeding is scheduled to consider a 603 megawatt unit in phase I of the proceedings, which are currently underway, and consider a second 603 megawatt unit in phase II of the proceedings, which are scheduled to begin in 2007. A report from the ALJs on phase I is expected in early 2007 and a report from the ALJs on phase II is expected in summer 2007.

On Sept. 5, 2006, NSP-Minnesota and other parties filed direct testimony in this proceeding. No party recommended approval of Excelsior s proposal. NSP-Minnesota presented its assessment that the proposal is not consistent with the requirements of Minnesota law and would impose substantial risks and costs for both customers and NSP-Minnesota. The Minnesota Department of Commerce presented testimony that the proposal did not meet a least-cost standard and that the public interest warrants consideration of other factors. Hearings are scheduled to begin in November 2006.

Parties including Xcel Energy Industrial Intervenors and the sponsors of the Minnesota Coal Gasification Plant Informational Website filed motions to dismiss Excelsior s petition on the grounds that it cannot comply with statutory requirements. Parties have the opportunity to reply to these motions. The ALJ held a hearing on the dispositions motions on Oct. 11, 2006, but has not yet issued a decision.

NSP-Minnesota intends to request that all costs associated with the proposed power purchase agreement, if approved, will be recoverable in customer rates.

NSP 2004 Resource Plan On Nov. 1, 2004, NSP-Minnesota filed its proposed resource plan for the period 2005 through 2019. The proposed plan identified needed resources and proposed processes for acquiring resources to meet those needs, which included the need for base load capacity beginning 2013. A series of comments and replies occurred on both the proposed plan and the proposed resource acquisition processes. On July 28, 2006, the MPUC issued an order that, among other things:

Approves NSP-Minnesota s proposal to proceed with a request for proposal for 136 megawatts of peaking resources with an intended in service date of 2011;

Identifies a base load resource need of 375 megawatts beginning in 2015 and requires NSP-Minnesota to file a certificate of need application for a proposed base load resource to begin the acquisition process by Nov. 1, 2006;

Requires NSP-Minnesota to file for any mandatory MPUC review or approvals of proposed upgrades to existing base load and nuclear power plants (Sherco, Prairie Island, and Monticello) by Dec. 31, 2006;

Approves an acquisition of 1,680 megawatts of wind generation resource over the planning period; and

Accepts the proposed increases in demand-side management and energy-savings goals.

NSP-Minnesota requested minor clarifications to the order, specifically asking that the Nov. 1, 2006 filing requirement be clarified to allow for a purchased power agreement and that the filing requirement for the upgrades be extended until Sept. 1, 2007 to accommodate scheduling and legislative review of the MPUC s decision in the Monticello certificate of need proceeding, pursuant to Minnesota law. On October 12, 2006, the Commission reheard its decision and approved minor modifications to its order that clarify these matters.

Monticello Certificate of Need In an October 23, 2006, Certificate of Need Order, the MPUC authorized an on-site, spent nuclear fuel, storage facility at the Monticello nuclear generating plant and up to 30 dry storage containers and storage vaults that will permit the plant to operate to 2030. By state statute, the MPUC s order becomes effective June 1, 2007, thus allowing the Minnesota legislature the opportunity to review the MPUC s decision. On May 24, 2005, the Nuclear Management Company (NMC), Xcel Energy s nuclear plant operating affiliate, submitted an application to the Nuclear Regulatory Commission (NRC) to extend the operating license for the Monticello plant from 2010 to 2030. To date, NRC staff have prepared a safety analysis and a Monticello plant specific supplement to the federal Environmental Impact Statement (EIS) concerning nuclear plant license renewals. The safety analysis supports license extension. The supplementary EIS finds no significant environmental impacts associated with extended operation of the Monticello plant. The NRC is expected to act on the operating license extension request by year end.

Other Regulatory Matters NSP-Wisconsin

2006 Fuel Cost Recovery Fuel costs for the Wisconsin retail jurisdiction through Sept. 30, 2006 were $2.8 million, or 2.3 percent lower than authorized in the 2006 rate case. Although the forecast shows higher costs for the remaining months of the year, NSP-Wisconsin anticipates fuel costs being outside the authorized range at year-end. Accordingly, NSP-Wisconsin established a $1.9 million fuel refund provision in the third quarter. The PSCW s investigation is ongoing. NSP-Wisconsin anticipates the PSCW will complete their investigation and issue an order early next year.

2007 Fuel Cost Recovery The PSCW order in NSP-Wisconsin s 2006 general rate case included a provision that allows NSP-Wisconsin to file an application to reopen the rate case for the limited purpose of re-pricing the fuel-related component of base electric rates for 2007. On Aug. 4, 2006, NSP-Wisconsin filed an application to reset the 2007 fuel base and monitoring range, and to increase electric base rates for 2007 by $22.6 million, or 5.0 percent, on an annual basis. The requested increase was driven primarily by higher renewable energy purchases and increases in coal commodity and transportation costs. On Sept. 1, 2006, the PSCW issued an order to reopen the case and, on Sept. 14, 2006, held a pre-hearing conference to identify the issues and set a procedural schedule for the case. On Oct. 16, 2006, the PSCW staff recommended adjustments to reduce NSP-Wisconsin s forecast fuel cost increase to $13.7 million, primarily based on decreases in natural gas and purchased power prices since the original filing on Aug. 4. NSP-Wisconsin will be allowed to make one final update to forecast prices in mid November so the PSCW s decision will be based on the most recent market price data. A hearing has been set for Nov. 7, 2006. In its application, NSP-Wisconsin requested a PSCW order before the end of 2006, with new rates to become effective Jan. 1, 2007.

Fuel Cost Recovery Rulemaking On June 22, 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. Instead, the statutes authorize the PSCW to approve, after a hearing, 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 opening this rulemaking, the PSCW recognized the increased volatility of fuel costs, citing events such as the implementation of the MISO Day 2 Market, increased demand on some fuels, increased transportation costs of some fuels, and the effects of hurricanes on the availability of some fuels. On Sept. 7, 2006, Wisconsin s large investor owned utilities, including NSP-Wisconsin, jointly filed proposed revisions to the rules. The utilities proposal incorporates a plan year forecast and an after-the-fact reconciliation to eliminate regulatory lag, and ensure recovery of prudently incurred costs. The PSCW has set a deadline of Oct. 30, 2006 for other parties, primarily customer and intervenor groups to submit a counter proposal. At this time it is not certain what, if any, changes to the existing rules will be recommended by the PSCW.

Wholesale Rate Case Application On July 31, 2006, NSP-Wisconsin filed a section 205 rate case at the FERC requesting a base rate increase of approximately $4 million, or 15 percent, for its ten wholesale municipal electric sales customers. The last rate increase for these customers was in 1993. NSP-Wisconsin s wholesale customers are currently served under a bundled full requirements tariff, with rates based on embedded costs, and a monthly fuel cost adjustment clause (FCAC). NSP-Wisconsin proposes to unbundle transmission service and revise the FCAC to reflect current FERC regulatory policies, the advent of MISO operations and the MISO Day 2 energy market. In August 2006, the ten customers filed a joint protest of the rate case, requesting the increase be suspended for the maximum five-month period (until March 1, 2007) and set for litigated hearings. The customers noted a question about the predicted 2006 sales forecast and requested that the FERC consider rejecting the filing entirely. NSP-Wisconsin filed an answer to the protest on Sept. 5, 2006, arguing the issues raised by the intervenors are appropriate for settlement or hearings. On Sept. 28, 2006, the FERC issued an order accepting the filing, suspending the effective date of the rates to March 1, 2007, and setting the filing for hearing and settlement judge procedures.

Other Regulatory Matters PSCo

Electric Commodity Adjustment (ECA) The ECA, effective Jan. 1, 2004, is an incentive adjustment mechanism that compares actual fuel and purchased energy expense in a calendar year to a benchmark formula. The ECA also provides for an $11.25 million cap on any cost sharing over or under an allowed ECA formula rate. The formula rate is revised annually and collected or refunded in the following year, if necessary. The current ECA mechanism will expire Jan. 1, 2007. Based on PSCo's analysis of the most recent forecast, a $10.3 million accrual was recorded in the third quarter of 2006.

Electric Rate Case In April 2006, PSCo filed with the Colorado Public Utilities Commission (CPUC) to increase electricity rates by $208 million annually, beginning Jan. 1, 2007. The request was based on two components, including an increase in base rate revenues of $178 million and an estimated $30 million increase in purchased capacity cost adjustment (PCCA) revenue. The base rate request was based on a return on equity of 11 percent, an equity ratio of 59.9 percent and an electric rate base of $3.4 billion. No interim rate increase was implemented. The PCCA request was based on 2007 projected costs and a revenue credit to customers for one wholesale contract.

On Aug. 18, 2006, PSCo received testimony from 10 intervenor groups, including the staff of the CPUC and the Office of Consumer Counsel (OCC). The intervenor testimony addressed a multitude of cost-of-service issues and recommended various reductions to PSCo s requested increase. The intervenors recommended increases, as subsequently corrected, ranged from $35 million to $91.4 million, exclusive of PCCA revenue. The CPUC staff recommended an overall base rate increase of $83 million. In addition, the staff generally agreed with PSCo s proposal for a PCCA mechanism through Dec. 31, 2009. The staff s filed case incorporated a 9.5 percent return on equity, adopted PSCo s recommended capital structure and reduced depreciation expense by $19.6 million annually.

The OCC recommended, as subsequently corrected, an overall base rate increase of $35 million, which incorporated an 8.5 percent return on equity, adopted PSCo s capital structure and reduced depreciation expense by $40.5 million annually.

On Sept. 29, 2006, PSCo filed answer testimony in which it advocated for a $206.6 million increase, composed of an approximate $172 million increase in base rate revenues, an estimated $30 million in PCCA revenue and an estimated $4.6 million in ECA revenue to recover certain WindSource program costs. PSCo continued to support an 11.0 percent return on equity, a 60 percent equity ratio and year-end rate base treatment of Comanche construction work in progress costs. The primary changes from the original filing were to propose the recovery of certain WindSource program revenues through the ECA mechanism rather than through base rates, and an update of pension and other benefits expense.

On Oct. 20, 2006, PSCo entered into a comprehensive settlement agreement with several of the parties to the case, including the CPUC staff, the OCC, the Colorado Energy Consumers, The Kroger Co., Climax Molybdenum Company, CF&I Steel, L.P., and the Commercial Group. If approved by the CPUC, the settlement would authorize an overall rate increase, effective Jan. 1, 2007. The settlement provides for an increase in base rates of $107 million, including an increase to depreciation expense of approximately $13.8 million and use of year-end 2006 rate base treatment for Comanche construction work in progress costs; an estimated $39.4 million in PCCA revenue and an estimated $4.6 million in ECA revenue to recover certain WindSource program costs. As a part of the total revenue increase of $151 million, the settlement also included the following terms:

A 10.50 percent return on equity and a 60 percent equity ratio;

A PCCA rider for all purchased capacity costs, with no revenue credit;

Recovery of certain WindSource-related costs through the ECA and the remainder through WindSource rates; and

Implementation of a residential late payment fee of 1.00 percent.

The settlement also provides for recovery of fuel and purchased energy costs through the ECA. The ECA mechanism would:

Change quarterly;

Allow for interest on any deferred balance;

As noted above, provide for recovery of WindSource-related costs from non-participating customers updated annually to reflect the system costs absent WindSource resources;

Provide for an incentive if targets for baseload energy production, or purchased energy benefits exceed certain thresholds. If the thresholds are exceeded, sharing under the ECA incentive would be 80 percent to customers and 20 percent to PSCo and

Sharing with customers of trading margins from system resources (generation-based trading) and non-system resources (proprietary trading) that are over and above the first approximately $1 million in margins achieved for each type of trading. The sharing percentage for generation-based trading is 80 percent to customers and 20 percent to PSCo; the sharing percentage for the proprietary trading is 20 percent to customers and 80 percent to PSCo.

In a filing made with the CPUC on Oct. 20, 2006, the parties requested that the CPUC delay hearings currently scheduled to begin on Oct. 23, 2006 and hold hearings on the settlement beginning on Nov. 2, 2006.

2003 Resource Plan On June 2, 2006, PSCo filed a motion with the CPUC requesting permission to withdraw an earlier application it made, which requested CPUC approval to shorten the ten-year resource acquisition period of its 2003 resource plan by one year resulting in a nine year acquisition period (2004-2012). PSCo s original application also sought to reject all bids offering power supplies starting in 2013 that it received in response to its Feb. 24, 2005 all-source solicitation. On June 7, 2006, the CPUC approved PSCo s motion and directed PSCo to complete the evaluation of bids and negotiation of contracts offering new power supplies starting in year 2013 by Dec. 15, 2006. It also directed PSCo management to approve the selected contracts by Jan. 15, 2007.

Renewable Portfolio Standards In November 2004, an amendment to the Colorado statutes was passed by referendum requiring implementation of a renewable energy portfolio standard (RES) for electric service. The law requires PSCo to generate, or cause to be generated, a certain level of electricity from eligible renewable resources. During 2006, the CPUC determined that compliance with the RES should be measured through the acquisition of renewable energy credits either with or without the accompanying renewable energy; that the utility purchaser owns the renewable energy credits associated with existing contracts where the power purchase agreement is silent on the issue; that Colorado utilities should be required to file implementation plans and the methods utilities should use for determining the budget available for renewable resources. In April 2006, the CPUC issued rules that establish the process utilities are to follow in implementing the RES. PSCo filed its first annual compliance plan under these rules on Aug. 31, 2006. The plan demonstrates that PSCo will meet the RES beginning in 2007 as required.

On Dec. 1, 2005, PSCo filed with the CPUC to implement a new rate rider that would apply to each customer s total electric bill, providing approximately $22 million in annual revenue (1.0 percent of total retail revenue). The revenues collected under the rider will be used to acquire sufficient solar generation resources to meet the requirements of the Colorado renewable energy portfolio standard. On Feb. 14, 2006, PSCo and the other parties to the case filed a stipulation agreeing to reduce the rider to 0.60 percent. The CPUC approved the stipulation on Feb. 22, 2006. The rider became effective March 1, 2006. PSCo s compliance plan will address whether modification to the level of this rider is necessary to meet the requirements of the renewable energy portfolio standard.

On Aug. 31, 2006, PSCo filed with the CPUC an application for approval of its 2007 plan for compliance with the CPUC s RES rules. As a part of its plan, PSCo requested approval to continue its existing 0.60 percent RES adjustment rider. Through its existing resources and contracts entered into in 2006, PSCo anticipates having sufficient non-solar renewable energy resources to meet the standard through at least 2016. In June 2006, PSCo issued a request for proposal to provide solar renewable energy credits and expects to enter into contracts to meet its obligation for on-site solar resources. On Sept. 1, 2006, PSCo executed a twenty-year solar power purchase agreement, which will provide about 16,000 megawatt hours per year and accompanying solar renewable energy credits beginning in 2008.

Quality of Service Plan PSCo was required to make a filing regarding the future of its quality of service plan (QSP), which expires at the end of 2006. In the initial filing, PSCo proposed a service quality monitoring and reporting plan. After reviewing the responses of the CPUC staff and other intervenors, PSCo negotiated a new QSP that will extend through calendar year 2010. The plan establishes performance measures and provides for associated bill credits for failure to achieve regional electric distribution system reliability, electric service continuity and restoration thresholds, customer complaints and telephone response times. If the performance thresholds are not met, the annual bill credit exposures are approximately $7 million for regional reliability and $1 million each for the continuity, reliability, customer complaints and telephone response time thresholds. Each of PSCo s nine operating regions has its own calculated reliability metric and the bill credits would be apportioned among the regions. PSCo would have to fail the operating threshold two years in a row before paying reliability bill credits. The bill credit levels would not escalate. If the credits are required to be paid, the stated amounts would be grossed up for taxes. The proposed plan is pending CPUC approval.

PSCo entered into a separate stipulation with the local government intervenors and the City of Boulder regarding certain issues they raised in the QSP proceeding.PSCo agreed to incorporate provisions in its electric tariff regarding conducting regular street light outage surveys and establishing benchmarks for standard outage rates and streetlight and traffic signal restoration. The electric tariff will provide for a charge to conduct the street light surveys. The tariff also will provide for payment of credits if PSCo does not restore street lights within a defined period. The CPUC conducted hearings regarding the QSP settlements and deliberated on the new QSP on Sept. 27, 2006. In deliberations, the CPUC approved the as-settled QSP with some modifications. The CPUC requires PSCo to file a replacement QSP by 2010 and to modify some reporting requirements. The CPUC has not issued a final order.

Controlled Outage Investigation On July 7, 2006, the CPUC discussed a CPUC staff report regarding its investigation of the controlled outages of Feb. 18, 2006, which affected an estimated 323,000 customers in Colorado for approximately 30 minutes. The investigation reviewed natural gas supply issues, the causes of unplanned outages on several PSCo-owned and independent power generation facilities, transmission availability, customer interruption procedures, emergency preparedness and internal and external communications. The CPUC report made over 90 recommendations and directed PSCo to respond within two weeks with its plans to implement certain procedures to address curtailment situations if they arise this summer. The CPUC s recommendations are directed at ensuring that there is an appropriate level of situational awareness between the operational status of the interdependent gas and electric supply systems so that adequate pipeline delivery pressures are available during critical peak periods. PSCo responded to the report of the CPUC and is in the process of implementing the recommendations. The final order has not been issued by the CPUC.

Other Regulatory Matters SPS

Wholesale Rate Complaints In November 2004, Golden Spread Electric, Lyntegar Electric, Farmer s Electric, Lea County Electric, Central Valley Electric and Roosevelt County Electric, wholesale cooperative customers of SPS, filed a rate complaint at the FERC. The complaint alleged that SPS rates for wholesale service were excessive and that SPS had incorrectly calculated monthly fuel cost adjustments using the FCAC provisions contained in SPS wholesale rate schedules. Among other things, the complainants asserted that SPS was not properly calculating the fuel costs that are eligible for FCAC recovery to reflect fuel costs recovered from certain wholesale sales to other utilities, and that SPS had inappropriately allocated average fuel and purchased power costs to other of SPS wholesale customers, effectively raising the fuel costs charges to complainants. Cap Rock Energy Corporation (Cap Rock), another full-requirements customer, Public Service Company of New Mexico (PNM) and Occidental Permian Ltd. and Occidental Power Marketing, L.P. (Occidental) intervened in the proceeding. Hearings on the complaint were held in February and March 2006.

On May 24, 2006, a FERC ALJ issued an initial recommended decision in the proceeding. The FERC will review the initial recommendation and issue a final order. SPS and others have filed exceptions to the ALJ s initial recommendation. FERC s order may or may not follow any of the ALJ s recommendation.

In the recommended decision, the ALJ resolved a number of disputed cost of service issues and ordered a compliance filing to determine the extent to which base revenues recovered under currently effective rates for the period beginning Jan. 1, 2005, through June 11, 2006 should be refunded to wholesale customers. The ALJ also found that SPS should recalculate its FCAC billings for the period beginning Jan. 1, 1999, to reduce the fuel and purchased power costs recovered from the complaining customers by allocating incremental fuel costs incurred by SPS in making wholesale sales of system firm capacity and associated energy to other firm customers at market-based rates during this period based on the view that such sales should be treated as opportunity sales.

SPS believes the ALJ erred on significant and material issues that contradict FERC policy or rules of law. Specifically, SPS believes, based on FERC rules and precedent, that it has appropriately applied its FCAC tariff to the proper classes of customers. These market-based sales were of a long-term duration under FERC precedent and were made from SPS entire system. Accordingly, SPS believes that the ALJ erred in concluding that these transactions were opportunity sales, which require the assignment of incremental costs.

The FERC has approved system average cost allocation treatment in previous filings by SPS for sales having similar service characteristics and previously accepted for filing certain of the challenged agreements with average fuel cost pricing. The ALJ failed to acknowledge either factor.

Moreover, SPS believes that the ALJ s recommendation constituted a violation of the Filed Rate Doctrine in that it effectively results in a retroactive amendment to the SPS FERC-approved FCAC tariff provisions. Under existing rules of law and FERC regulations, the FERC may modify a previously approved FCAC on a prospective basis. Accordingly, SPS believes it has applied its FCAC correctly and has sought review of the recommended decision by the FERC by filing a brief on the exceptions.

Based on FERC regulations and rules of law, SPS has evaluated all sales made from Jan. 1, 1999, to Dec. 31, 2005. While SPS believes it should ultimately prevail in this proceeding, SPS has accrued approximately $7 million, related to both the base-rate and fuel items. However, if the FERC were to adopt the majority of the ALJ s recommendations, SPS refund exposure could be approximately $50 million.

On Sept. 15, 2005, PNM filed a separate complaint at the FERC in which it contended that its demand charge under an existing interruptible power supply contract with SPS is excessive and that SPS has overcharged PNM for fuel costs under three separate agreements through erroneous FCAC calculations. PNM s arguments were consistent with those that it made as an intervenor in the cooperatives complaint case. SPS submitted a response to PNM s complaint in October 2005. In November 2005, the FERC accepted PNM s complaint. In July 2006, SPS and PNM reached a settlement in principle and a settlement agreement was filed for approval on Sept. 19, 2006. As a consequence, SPS has accrued approximately $1.3 million to settle all related issues for this complaint.

Wholesale Power Base Rate Application On Dec. 1, 2005, SPS filed for a $2.5 million increase in wholesale power rates to certain electric cooperatives. On Jan. 31, 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. The case is presently in the settlement judge procedures and an agreement in principle has been reached for base rates for the full-requirements customers and PNM; one other wholesale customer has not settled, however. On Sept. 7, 2006, the offer of settlement with respect to the full-requirements customer was filed for approval and on Sept. 19, 2006, the offer of settlement with respect to PNM was filed for approval.Hearings have been scheduled for April 2007 for the base rates applicable to the remaining non-settling wholesale customer.

Resource Planning In June 2006, the New Mexico Public Regulation Commission (NMPRC) initiated a series of workshops for the purpose of drafting rules for integrated resource planning. In August 2006, workshop participants completed a consensus rule that was forwarded by the Hearing Examiner on October 3, 2006, to the NMPRC for consideration. The proposed rules would apply to jurisdictional electric and gas utilities, such as SPS, that operate within the state.

SPP Energy Imbalance Service On June 15, 2005, SPP, of which SPS is a member, filed proposed tariff provisions to establish an Energy Imbalance Service (EIS) wholesale energy market for the SPP region to be effective March 1, 2006. This market is the first step in a phased approach toward the development of a more comprehensive market, which is expected to eventually include an ancillary services component and perhaps FTRs. On Sept. 19, 2005, the FERC issued an order rejecting the SPP EIS proposal and providing guidance and recommendations to SPP; however, the FERC did not require SPP to implement a full Day 2 market similar to MISO. On Jan. 4, 2006, SPP submitted proposed tariff revisions to implement an EIS market and establish a market monitoring and market power mitigation plan. On March 20, 2006, the FERC issued an order conditionally accepting the proposed market, suspending the implementation until Oct. 1, 2006. The FERC found the proposal lacking, particularly with respect to the hiring of an external market monitor, the loss compensation mechanisms and the lack of several standard forms for service. The FERC directed SPP to implement safeguards for the first six months of the imbalance markets including a two tier cap, a market readiness certification and price correction authority. The FERC also ordered balancing authorities to enter into an agreement delineating the respective responsibilities of balancing authorities and SPP in the EIS market.

SPP and market participants engaged in a series of technical conferences to reach agreement on the issue of responsibilities of balancing authorities and SPP in order to comply with the FERC s order. On May 19, 2006, SPP filed proposed tariff revisions pursuant to the FERC s January 4th Order. Several parties filed comments and protests to the SPP compliance filing, including SPS. SPP filed an answer to the protests. On July 20, 2006, the FERC accepted in part, and rejected in part, SPP s proposed market provisions, to become effective on Oct. 1, 2006. On Sept. 26, 2006, the FERC denied requests for rehearing of the March 20, 2006 order. On Oct. 24, 2006, SPP informed FERC that the market would not start on Nov. 1; instead, SPP will evaluate on Dec. 12 a Feb. 1, 2007, market start date. SPS is continuing to participate in pre-operational trials. SPS has concluded that neither NMPRC nor

Public Utility Commission of Texas (PUCT) approval is required for SPS to participate in the EIS market.

Texas Energy Legislation The 2005 Texas Legislature passed a law, effective June 18, 2005, establishing statutory authority for electric utilities outside of the Electric Reliability Council of Texas in the SPP or the Western Electricity Coordinating Council to have timely recovery of transmission infrastructure investments. After notice and hearing, the PUCT may allow recovery on an annual basis of the reasonable and necessary expenditures for transmission infrastructure improvement costs and changes in wholesale transmission charges under a tariff approved by the FERC. The PUCT will initiate a rulemaking for this process that is expected to take place in the second half of 2006.

Fuel Cost Recovery Mechanisms Fuel and purchased energy costs are recovered in Texas through a fixed-fuel and purchased energy recovery factor, which is part of SPS retail electric rates. The Texas retail fuel factors change each November and May based on the projected cost of natural gas. If it appears SPS will materially over-recover or under-recover these costs, the factor may be revised based on application by SPS or action by the PUCT. In 2006, SPS revised its estimate of the allocation of fuel under-recoveries to its Texas jurisdiction for 2004 and 2005 based on a distribution system loss approach. As of Sept. 30, 2006, the total unrecovered fuel balance is $25.3 million. Because of uncertainty regarding ultimate recovery, a settlement reserve was recorded equal to the entire amount of the unrecovered fuel balance. SPS filed a fuel reconciliation application in May 2006. See further discussion below.

Texas Retail Fuel Factor Change On Oct. 6, 2006, SPS filed an application to change its fuel factors effective Nov. 1, 2006, to more accurately track fuel cost during the winter months. On Oct. 16, 2006, the PUCT granted interim approval of the factor changes effective November 2006.

Texas Retail Fuel Surcharge Case On May 5, 2006, SPS requested authority to surcharge approximately $45.5 million of Texas retail fuel and purchased energy cost under-collection that accrued from October 2005 through March 2006. The case was referred to the State Office Of Administrative Hearing (SOAH) for a contested hearing on its merits on Aug. 14, 2006. During the course of this proceeding, certain customers challenged whether a wholesale firm sales contract that SPS has with El Paso Electric Company (EPE) satisfied the terms of a non-unanimous stipulation, dated April 25, 2005, and the PUCT s final order, dated Dec. 19, 2005, which established the terms under which SPS would be allowed to recover system average fuel cost from certain wholesale firm sales contracts until the issue is addressed in SPS base rate case. On Sept. 21, 2006, the PUCT announced its decision that the contract with EPE, which was entered into in July 2004, and prior to the non-unanimous stipulation and final order referred to above and which commenced delivery on Jan. 1, 2006, did not conform to the non-unanimous stipulation and the PUCT s December 2005 final order and, as a result, disallowed approximately $1.8 million in fuel costs for the period covering October 2005 through March 2006. On Oct. 13, 2006, the PUCT issued a written order confirming its Sept. 21, 2006 rulings, which will control fuel cost recovery for the current EPE contract until a final order in the pending retail rate case discussed below is issued. If the PUCT order stands, a preliminary estimate indicates the disallowance could approximate $8 million for the entire fiscal year, of which approximately $6.4 million has been accrued as of Sept. 30, 2006. SPS will take steps to mitigate the impact of the Sept. 21, 2006 decision. Recovery of the remaining portion of the surcharge of approximately $39 million began on October 1, 2006.

Texas Retail Base Rate And Fuel Reconciliation Case On May 31, 2006, SPS filed a Texas retail electric rate case requesting an increase in annual revenues of approximately $48 million, or 6.0 percent. The rate filing is based on a historical test year, an electric rate base of $943 million, a requested return on equity of 11.6 percent and a common equity ratio of 51.1 percent. On Sept. 25, 2006, SPS filed corrections to its rate case revenue requirements calculations increasing the revenue requirements an additional $15 million in annual revenues, to approximately $63 million. The principal revision involves SPS jurisdictional allocator and the overstatement of wholesale transmission revenue credits. In order to establish new rates as quickly as possible, SPS does not currently anticipate refiling the entire case. As a result, SPS will be limited to the $48 million increase originally requested. Final rates are now expected to be effective in the second quarter of 2007. No interim rate increase has been implemented. A new procedural schedule in the case has been established and is listed below.

Intervenor Testimony	Dec. 15, 2006
PUCT Staff Testimony	Jan. 12, 2007
SPS Rebuttal Testimony	Jan. 25, 2007
HearingsJan. 31 through	Feb. 23, 2007
Decision	May 1, 2007

The fuel reconciliation portion requests approval of approximately $957 million of Texas jurisdictional fuel and purchased power costs for the 2004 through 2005 period. The fuel reconciliation case was transferred to the SOAH with the base rate case and has the same procedural schedule. As a part of the fuel reconciliation case, fuel and purchased energy costs, which are recovered in Texas through a fixed-fuel and purchased energy recovery factor as a part of SPS retail electric rates, will be reviewed.

New Mexico Fuel Review On Jan. 28, 2005, the NMPRC accepted the staff petition for a review of SPS fuel and purchased power cost. The staff requested a formal review of SPS fuel and purchased power cost adjustment clause (FPPCAC) for the period of Oct. 1, 2001 through August 2004. The hearing in the fuel review case was held April 22, 2006. A proposed recommended decision was filed by the parties on July 28, 2006, and a NMPRC decision is expected in late 2006.

New Mexico Fuel Factor Continuation Filing On Aug. 18, 2005, SPS filed with the NMPRC requesting continuation of the use of SPS FPPCAC and current monthly factor cost recovery methodology. This filing was required by NMPRC rule. Testimony has been 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 ineligible 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 have requested disallowances for past periods, which in the aggregate total approximately $45 million. Other issues in the case include the treatment of renewable energy certificates and sulfur dioxide allowance credit proceeds in relation to SPS New Mexico retail fuel and purchased power recovery clause. The hearing was held in April 2006, and a NMPRC decision is expected in late 2006.

5. Commitments and Contingent Liabilities

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 is pursuing or intends to pursue insurance claims and believes it will recover some portion of these costs through such claims. Additionally, where applicable, the subsidiary involved is pursuing, or intends to pursue, recovery from other potentially responsible parties 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 for such unrecoverable amounts in its consolidated financial statements.

Ashland Manufactured Gas Plant Site NSP-Wisconsin was named a potentially responsible party (PRP) for creosote and coal tar contamination at a site in Ashland, Wis. The Ashland site includes property owned by NSP-Wisconsin, which was previously a manufactured gas plant (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. The U.S. Environmental Protection Agency (EPA) and Wisconsin Department of Natural Resources (WDNR) have not yet selected the method of remediation to use at the site. 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 cost of remediating the Ashland site is not determinable. NSP-Wisconsin has recorded a liability of $25.0 million for its potential liability for remediating the Ashland site and for external legal and consultant costs. Since NSP-Wisconsin cannot currently estimate the cost of remediating the Ashland site, that portion of the recorded liability related to remediation is based upon the minimum of the estimated range of remediation costs using information available to date and reasonably effective remedial methods.

Regional Haze Rules The EPA requires states to develop implementation plans to comply with regional haze rules that require emission controls, known as best available retrofit technology (BART), by December 2007. States are required to identify the facilities that will have to reduce emissions under BART and then set BART emissions limits for those facilities. Colorado is the first state in Xcel Energy s region to begin its BART rule development as the first step toward the December 2007 deadline. Xcel Energy is actively involved in the stakeholder process in Colorado and will also be involved as other states in its service territory begin their process. On May 30, 2006, the Colorado Air Quality Control Commission promulgated BART regulations requiring certain major stationary sources to evaluate and install, operate and maintain BART technology or an approved BART alternative to make reasonable progress toward meeting the national visibility goal. On Aug. 1, 2006, PSCo submitted its BART alternatives analysis to the Colorado Air Pollution Control Division. As set forth in its analysis, PSCo estimates that implementation of the BART alternatives will cost approximately $165 million in capital costs, which includes approximately $62 million in environmental upgrades for the existing Comanche Station project. Xcel Energy expects the cost of any required capital investment will be recoverable from customers. Emissions controls are expected to be installed between 2010 and 2012 and must be operational by 2013.

Minnesota has begun implementing its BART strategy as the first step toward the December 2007 deadline. NSP-Minnesota submitted its BART alternatives analysis for Sherco units 1 and 2 on Oct. 26, 2006. The expected cost associated with the range of alternatives for additional emission controls for sulfur dioxide (SO_2) and nitrogen oxide (NOx) is a capital investment of $7 million to

$617 million. NSP- Minnesota supports the alternative with the associated cost estimate of $7 million; however, NSP-Minnesota has not yet received a response from the Minnesota Pollution Control Agency (MPCA) concerning its preferred alternative. Xcel Energy expects that the costs of any required capital investment will be recoverable from customers.

Clean Air Interstate Rule In March 2005, the EPA issued the Clean Air Interstate Rule (CAIR), which further regulates SO_2 and NOx emissions. Under CAIR s cap-and-trade structure, utilities can comply through capital investments in emission controls or purchase of emission allowances from other utilities making reductions on their systems. There is uncertainty concerning implementation of CAIR. States are required to develop implementation plans within 18 months of the issuance of the new rules and have a significant amount of discretion in the implementation details. Legal challenges to CAIR rules could alter their requirements and/or schedule. The uncertainty associated with the final CAIR rules makes it difficult to predict the ultimate amount and timing of capital expenditures and operating expenses.

The Texas Commission on Environmental Quality (TCEQ) adopted the EPA CAIR without further state regulatory requirements.

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 National Ambient Air Quality Standard in any downwind jurisdiction. On July 11, 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 CAIR. El Paso Electric Co. joined in the request for reconsideration. On March 15, 2006, the EPA denied the petition for reconsideration. On June 27, 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 United States Court of Appeals for the District of Columbia Circuit.

Based on the preliminary analysis of various scenarios of capital investment and allowance purchases, Xcel Energy currently believes the preferred scenario for SPS will be capital investments of approximately $30 million for NO_x controls with NO_x allowance purchases of an estimated $4 million in 2009. Annual purchases of SO_2 allowances are estimated in the range of $15 million to $25 million each year, beginning in 2012 for phase I based on allowance costs and fuel quality as of July 2006.

On June 13, 2006, the MPCA issued a draft rule for implementing the CAIR in Minnesota, which further regulates SO_2 and NO_x emissions. This proposal would require more stringent emission reductions than the federal CAIR program, resulting in additional implementation costs. A stakeholder process is ongoing, and a proposed rule is expected in November 2006.

While Xcel Energy expects to comply with the new rules through a combination of additional capital investments in emission controls at various facilities and purchases of emission allowances, it is continuing to review the alternatives. Xcel Energy believes the cost of any required capital investment or allowance purchases will be recoverable from customers.

Clean Air Mercury Rule In March 2005, the EPA issued the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from power plants for the first time. Compliance may be achieved by either adding mercury controls or purchasing allowances or a combination of both. The capital cost is estimated to be $29.3 million for the mercury control equipment. The TCEQ adopted the CAMR without further state regulatory requirements. Xcel Energy continues to evaluate the strategy for complying with CAMR. On June 6, 2006, the Colorado Department of Public Health and Environment issued a draft rule for implementing CAMR in Colorado. The proposed rule provides for fewer mercury allowances than the federal program, which may result in additional implementation costs. The state of Colorado is required to submit a plan to EPA by Oct. 31, 2006 to limit mercury emissions from coal-fired electric utility steam generating units consistent with federal standards of performance. A stakeholder process is ongoing, with a hearing before the Colorado Air Quality Control Commission currently scheduled for Nov. 16-17, 2006.

Minnesota Mercury Legislation On May 2, 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 Sherburne County generating facilities. Under the Act, Xcel Energy must install, maintain and operate continuous mercury emission monitoring systems or other monitoring methods approved by the MPCA at these units by July 1, 2007. The information obtained will be used to establish a baseline from which to measure mercury emission reductions. Mercury emission reduction plans must 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 reduce emissions by 90 percent. Implementation would occur by Dec. 31, 2010 for dry scrubbed units 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 not currently estimable. 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.On Sept. 15, 2006, NSP-Minnesota filed a request with the MPUC for deferred accounting of up to $6.3 million of certain environmental improvement costs that are expected to be recoverable under the Act. If approved, this petition would defer recovery of these 2006 and 2007 costs until such time as the new tariff and rate rider mechanism are developed and approved by the MPUC.

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.

Sinclair Oil Corporation vs. e prime, inc. and Xcel Energy, Inc. - On July 18, 2005, Sinclair Oil Corporation filed a lawsuit against Xcel Energy and its former subsidiary e prime, inc. in the U.S. District Court for the Northern District of Oklahoma alleging liability and damages for purported misreporting of price information for natural gas to trade publications in an effort to artificially increase natural gas prices. The complaint also alleges that e prime and Xcel Energy engaged in a conspiracy with other gas sellers to inflate prices through alleged false reporting of gas prices. In response, e prime and Xcel Energy filed a motion with the Multi-District Litigation (MDL) panel to have the matter transferred to U.S. District Judge Pro, who is the judge assigned to western area wholesale natural gas marketing litigation and filed a second motion to dismiss the lawsuit. In response to this motion, this matter was conditionally transferred to U.S. District Court Judge Pro. Judge Pro granted the motion to dismiss, and Sinclair appealed to the Ninth Circuit Court of Appeals. Sinclair s appeal has been stayed pending the Ninth Circuit s disposition of the Abelman Art Glass appeal, as disclosed previously in Note 14 to the consolidated financial statements in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005.

Ever-Bloom Inc. vs. Xcel Energy Inc. and e prime et al. - On June 21, 2005, a class action complaint was filed in the U.S. District Court for the Eastern District of California by Ever-Bloom, Inc. The lawsuit names as defendants, among others, Xcel Energy and e prime. The lawsuit, filed on behalf of a purported class of gas purchasers, alleges that defendants falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices in California, purportedly in violation of the Sherman Act. This matter has been stayed pending the outcome of cases on appeal to the Ninth Circuit Court of Appeals.

Learjet, Inc. vs. e prime and Xcel Energy et al. On Nov. 4, 2005, a purported class action complaint was filed in state court for Wyandotte County of Kansas on behalf of all natural gas producers in Kansas. The lawsuit alleges that e prime, Xcel Energy and other named defendants conspired to raise the market price of natural gas in Kansas by, among other things, inaccurately reporting price and volume information to the market trade publications. On Dec. 7, 2005, the state court granted the defendants motion to remove this matter to the U.S. District Court in Kansas. Plaintiffs have filed a motion for remand, which was denied on Aug. 3, 2006. Plaintiffs in this matter and in the J.P. Morgan Trust case, discussed below, have moved the Judicial Panel on MDL for a separate MDL docket to be set up in Kansas Federal Court.

J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al. On Oct. 17, 2005, J.P. Morgan Trust Company, in its capacity as the liquidating trustee for Farmland Industries Liquidating Trust, filed an amended complaint in Kansas state court adding defendants, including Xcel Energy and e prime, to a previously filed complaint alleging that the defendants inaccurately reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices. The lawsuit was removed to the U.S. District Court in Kansas and subsequently transferred to U.S. District Court Judge Pro in Nevada pursuant to an order from the MDL panel. A motion to remand to state court filed by plaintiffs has been denied. A motion to dismiss plaintiff s case is pending.

Metropolitan Airports Commission vs. Northern States Power Company On Dec. 30, 2004, the Metropolitan Airports Commission (MAC) filed a complaint in Minnesota state district court in Hennepin County asserting that NSP-Minnesota is required to relocate facilities on MAC property at the expense of NSP-Minnesota. MAC claims that approximately $7.1 million charged by NSP-Minnesota over the past five years for relocation costs should be repaid. Both parties asserted cross motions for partial summary judgment on a separate and less significant claim concerning legal obligations associated with rent payments allegedly due and owing by NSP-Minnesota to MAC for the use of its property for a substation that serves MAC. A hearing regarding these cross motions was held in January 2006. In February 2006, the court granted MAC s motion on this issue, finding that there was a valid lease and that the past course of action between the parties required NSP-Minnesota to continue making rent payments. NSP-Minnesota had made rent payments for 45 years. Depositions of key witnesses took place in February, March and April of 2006. The parties entered into meaningful settlement negotiations in May 2006, and in August 2006 reached an oral settlement of the dispute. Formal written settlement documents are expected to be executed and the action formally dismissed in the near future.

Hoffman vs. Northern States Power Company On March 15, 2006, a purported class action complaint was filed in Minnesota state district court in Hennepin County, 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. NSP-Minnesota has filed a motion for dismissal on the pleadings, which was heard on Aug. 16, 2006.

Comer vs. Xcel Energy Inc. et al. On April 25, 2006, Xcel Energy received notice of a purported class action lawsuit filed in U.S. District Court for 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 carbon dioxide 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 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. On July 19, 2006, Xcel Energy filed a motion to dismiss the lawsuit in its entirety.

Bender et al. vs. Xcel Energy On July 2, 2004, five former NRG officers filed a lawsuit against Xcel Energy in the U.S. District Court for the District of Minnesota. The lawsuit alleges, among other things, that Xcel Energy violated the Employee Retirement Income Security Act of 1974 (ERISA) by refusing to make certain deferred compensation payments to the plaintiffs. The complaint also alleges interference with ERISA benefits, breach of contract related to the nonpayment of certain stock options and unjust enrichment. The complaint alleges damages of approximately $6 million. Xcel Energy believes the suit is without merit. On Jan. 19, 2005, Xcel Energy filed a motion for summary judgment. On July 26, 2005, the court issued an order granting Xcel Energy s motion for summary judgment in part with respect to claims for interference with ERISA benefits, breach of contract for nonpayment of stock options and unjust enrichment. The court denied Xcel Energy s motion in part with respect to the allegations of nonpayment of deferred compensation benefits. Plaintiffs and Xcel Energy have filed additional cross motions for summary judgment, with oral arguments presented on Feb. 24, 2006.

On May 17, 2006, the court granted Xcel Energy s motion for summary judgment in full and denied the plaintiff s motion for summary judgment in full. Plaintiffs have appealed to the Eighth Circuit Court of Appeals.

Comanche 3 Permit Litigation - On Aug. 4, 2005, Citizens for Clean Air and Water in Pueblo and Southern Colorado and Clean Energy Action filed a complaint against the Colorado Air Pollution Control Division 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. On June 20, 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 have appealed this decision.

Breckenridge Brewery vs. e prime and Xcel Energy Inc. et al. In May, 2006, Breckenridge Brewery, a Colorado corporation, filed a complaint in Colorado State District Court for the City and County of Denver alleging that the defendants, including e prime and Xcel Energy, unlawfully prevented full and free competition in the trading and sale of natural gas, or controlled the market price of natural gas, and engaged in a conspiracy in constraint of trade. Notice of removal to federal court on behalf of Xcel Energy Inc. and e prime, inc. was filed in June 2006. On July 6, 2006, the Colorado State District Court granted an enlargement of time within which to file a pleading in response to the complaint. Plaintiffs have filed a motion to remand the matter to state court, which is pending.

Carbon Dioxide Emissions Lawsuit On July 21, 2004, the attorneys general of eight states and New York City, as well as several environmental groups, filed lawsuits in U.S. District Court for the Southern District of New York against five utilities, including Xcel Energy, to force reductions in carbon dioxide (CO2) emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. CO2 is emitted whenever fossil fuel is combusted, such as in automobiles, industrial operations and coal- or gas-fired power plants. The lawsuits allege that CO2 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 CO2 emissions. In October 2004, Xcel Energy and four other utility companies filed a motion to dismiss the lawsuit, contending, among other reasons, that the lawsuit is an attempt to usurp the policy-setting role of the U.S. Congress and the president. On Sept. 19, 2005, the judge granted the defendants motion to dismiss on constitutional grounds. Plaintiffs filed an appeal to the Second Circuit Court of Appeals. Oral arguments were presented on June 7, 2006 and a decision on the appeal is pending.

Missouri Public Service Commission vs. e prime, inc. and Xcel Energy Inc. - On Oct. 24, 2006, the Missouri Public Utilities Commission filed a complaint in state court for Jackson County of Missouri alleging that defendants e prime, Xcel Energy and 21 other defendants falsely reported natural gas trades to market trade publications in an effort to artificially raise natural gas prices. The complaint further alleges that such conduct constitutes a violation of the Missouri Antitrust Law, fraud and unjust enrichment. Xcel Energy and e prime deny these allegations and intend to vigorously defend themselves in this action.

Other Contingencies

The circumstances set forth in Notes 13, 14 and 15 to the consolidated financial statements in Xcel Energy s Annual Report on Form

10-K for the year ended Dec. 31, 2005 and Notes 3, 4 and 5 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:

Tax Matters See Note 3 to the consolidated financial statements for discussion of exposures regarding the tax deductibility of corporate-owned life insurance loan interest; and

Guarantees See Note 6 to the consolidated financial statements for discussion of exposures under various guarantees.

6. Short-Term Borrowings and Other Financing Instruments

Short-Term Borrowings

At Sept. 30, 2006, Xcel Energy and its subsidiaries had $350 million of short-term debt outstanding at a weighted average yield of 5.43 percent.

Guarantees

Xcel Energy provides various guarantees and bond indemnities supporting certain of its 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 Sept. 30, 2006, Xcel Energy had issued guarantees of up to $71.5 million with no 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 Sept. 30, 2006, was approximately $118.5 million. 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.

7. Derivative Valuation and Financial Impacts

Xcel Energy and its subsidiaries use a number of different derivative instruments in connection with their utility operations, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. These derivatives instruments are utilized in connection with various commodity prices; certain energy related products, including emission allowances and renewable energy credits, and interest rates. All derivative instruments not qualifying for the normal purchases and normal sales exception, as defined by SFAS No. 133- Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133), are recorded at fair value. The presentation of these derivative instruments is dependent on the designation of a qualifying hedging relationship. The adjustment to fair value of derivative instruments not designated in a qualifying hedging relationship is reflected in current earnings or as a regulatory balance. This classification is dependent on the applicability of specific regulation. This includes certain instruments used to mitigate market risk for the utility operations and all instruments related to the commodity trading operations. The designation of a cash flow hedge permits the classification of fair value to be recorded within Other Comprehensive Income, to the extent effective. The designation of a fair value hedge permits a derivative instrument s gains or losses to offset the related results of the hedged item in the Consolidated Statements of Income.

Xcel Energy records the fair value of its derivative instruments in its Consolidated Balance Sheets as separate line items identified as Derivative Instruments Valuation in both current and noncurrent assets and liabilities.

The fair value of all interest rate swaps is determined through counterparty valuations, internal valuations and broker quotes. There have been no material changes in the techniques or models used in the valuation of interest rate swaps during the periods presented.

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 in which Xcel Energy and its subsidiaries are currently engaged are discussed below.

Cash Flow Hedges

Xcel Energy and its subsidiaries enter into derivative instruments to manage variability of future cash flows from changes in commodity prices and interest rates. These derivative instruments are designated as cash flow hedges for accounting purposes, and the changes in the fair value of these instruments are recorded as a component of Other Comprehensive Income or deferred as a regulatory asset or liability.

At Sept. 30, 2006, Xcel Energy and its utility subsidiaries had various commodity-related contracts designated as cash flow hedges extending through 2009. The fair value of these cash flow hedges is recorded in either Other Comprehensive Income or deferred as a regulatory asset or liability. This classification is based on the regulatory recovery mechanisms in place. Amounts deferred in these accounts are recorded in earnings as the hedged purchase or sales transaction is settled. 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. As of Sept. 30, 2006, Xcel Energy had no amounts in Accumulated Other Comprehensive Income related to commodity cash flow hedge contracts that are expected to be recognized in earnings during the next 12 months as the hedged transactions settle.

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, and the change in the fair value of these instruments is recorded as a component of Other Comprehensive Income. As of Sept. 30, 2006, Xcel Energy had net gains of approximately $2.9 million in Accumulated Other Comprehensive Income related to interest rate cash flow hedge contracts that are expected to be recognized in earnings during the next 12 months.

Gains or losses on hedging transactions for the sales of energy or energy-related products are recorded as a component of revenue, hedging transactions for fuel used in energy generation are recorded as a component of fuel costs, hedging transactions for gas purchased for resale are recorded as a component of gas costs and interest rate hedging transactions are recorded as a component of interest expense. Certain utility subsidiaries are allowed to recover in electric or gas rates the costs of certain financial instruments purchased to reduce commodity cost volatility. There was an immaterial amount of ineffectiveness in the third quarter of 2006.

The impact of qualifying cash flow hedges on Xcel Energy s Accumulated Other Comprehensive Income, included in the Consolidated Statements of Stockholders Equity and Comprehensive Income, is detailed in the following table:

(Millions of Dollars)	**Three months ended Sept. 30, 2006**	**2005**
Accumulated other comprehensive income related to cash flow hedges at June 30	$ 19.5	$ (22.4)
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	(16.1)	17.0
After-tax net realized gains on derivative transactions reclassified into earnings	0.2	(5.0)
Accumulated other comprehensive income (loss) related to cash flow hedges at Sept. 30	$ 3.6	$ (10.4)

(Millions of Dollars)	**Nine months ended Sept. 30, 2006**	**2005**
Accumulated other comprehensive (loss) income related to cash flow hedges at Dec. 31	$ (8.8)	$ 0.1
After-tax net unrealized gains (losses) related to derivatives accounted for as hedges	12.7	(0.9)
After-tax net realized gains on derivative transactions reclassified into earnings	(0.3)	(9.6)
Accumulated other comprehensive income (loss) related to cash flow hedges at Sept. 30	$ 3.6	$ (10.4)

Fair Value Hedges

The effective portion of the change in the fair value of a derivative instrument qualifying as a fair value hedge is offset against the change in the fair value of the underlying asset, liability or firm commitment being hedged. That is, fair value hedge accounting allows the gains or losses of the derivative instrument to offset, in the same period, the gains and losses of the hedged item.

Derivatives Not Qualifying for Hedge Accounting

Xcel Energy and its subsidiaries have commodity trading operations that enter into derivative instruments. These derivative instruments are accounted for on a mark-to-market basis in the Consolidated Statements of Income. The results of these transactions are recorded on a net basis within Operating Revenues on the Consolidated Statements of Income.

Xcel Energy and its subsidiaries also enter into certain commodity-based derivative transactions, not included in trading operations, which do not qualify for hedge accounting treatment. These derivative instruments are accounted for on a mark-to-market basis in accordance with SFAS No. 133.

Normal Purchases or Normal Sales Contracts

Xcel Energy s utility subsidiaries enter into contracts for the purchase and sale of various commodities for use in their business operations. SFAS No. 133 requires a company to evaluate these contracts to determine whether the contracts are derivatives. Certain contracts that literally meet the definition of a derivative may be exempted from SFAS No. 133 as normal purchases or normal sales. Normal purchases and normal sales are contracts that provide for the purchase or sale of something other than a financial or derivative instrument that will be delivered in quantities expected to be used or sold over a reasonable period in the normal course of business. In addition, normal purchases and normal sales contracts must have a price based on an underlying that is clearly and closely related to the asset being purchased or sold. An underlying is a specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable, including the occurrence or nonoccurrence of a specified event, such as a scheduled payment under a contract.

Xcel Energy evaluates all of its contracts when such contracts are entered to determine if they are derivatives and, if so, if they qualify to meet the normal designation requirements under SFAS No. 133. None of the contracts entered into within the commodity trading operations qualify for a normal designation.

In 2003, as a result of FASB Statement 133 Implementation Issue No. C20, Xcel Energy began recording several long-term power purchase 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 will no longer be 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 balances.

Normal purchases and normal sales contracts are accounted for as executory contracts as required under other generally accepted accounting principles (GAAP).

8. Detail of Interest and Other Income - Net

Interest and other income, net of nonoperating expenses, for the three and nine months ended Sept. 30 consisted of the following:

	Three months ended Sept. 30,	
(Thousands of Dollars)	**2006**	**2005**

Interest income	$ 4,296	$ 5,587
Equity income in unconsolidated affiliates	1,192	760
Other nonoperating income	588	1,449
Loss on the sale of investments	(722)	
Minority interest income	1,795	171
Interest expense on corporate-owned life insurance and other employee-related insurance policies	(4,972)	(3,540)
Other nonoperating expense	(28)	(2,497)
Total interest and other income - net	$ 2,149	$ 1,930

(Thousands of Dollars)	Nine months ended Sept. 30, 2006	2005
Interest income	$ 14,095	$ 12,226
Equity income in unconsolidated affiliates	3,470	2,073
Other nonoperating income	4,907	7,882
Loss on the sale of investments	(2,540)	
Minority interest income	2,098	689
Interest expense on corporate-owned life insurance and other employee-related insurance policies	(18,530)	(13,076)
Other nonoperating expense	(814)	(5,429)
Total interest and other income - net	$ 2,686	$ 4,365

9. Common Stock and Equivalents

Xcel Energy has common stock equivalents consisting of convertible senior notes and stock options. The dilutive impacts of common stock equivalents affected earnings per share as follows for the three and nine months ending Sept. 30, 2006 and 2005:

	Three months ended Sept. 30, 2006			Three months ended Sept. 30, 2005		
(Amounts in thousands, except per share amounts)	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
Income from continuing operations	$ 224,175			$ 197,817		
Less: Dividend requirements on preferred stock	(1,060)			(1,060)		
Basic earnings per share:						
Income from continuing operations	223,115	406,123	$ 0.55	196,757	402,735	$ 0.49
Effect of dilutive securities:						
$230 million convertible debt	3,044	18,654		2,895	18,654	
$57.5 million convertible debt	743	4,663		724	4,663	
401(k) match		518				
Stock options		42			33	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 226,902	430,000	$ 0.53	$ 200,376	426,085	$ 0.47

	Nine months ended Sept. 30, 2006			Nine months ended Sept. 30, 2005		
(Amounts in thousands, except per share amounts)	Income	Shares	Per-share Amount	Income	Shares	Per-share Amount
Income from continuing operations	$ 471,923			$ 400,073		
Less: Dividend requirements on preferred stock	(3,180)			(3,180)		
Basic earnings per share:						
Income from continuing operations	468,743	405,234	$ 1.16	396,893	402,028	$ 0.99
Effect of dilutive securities:						
$230 million convertible debt	9,046	18,654		8,603	18,654	
$57.5 million convertible debt	2,262	4,663		2,151	4,663	
401(k) match		517				
Stock options		27			23	
Diluted earnings per share:						
Income from continuing operations and assumed conversions	$ 480,051	429,095	$ 1.12	$ 407,647	425,368	$ 0.96

10. Benefit Plans and Other Postretirement Benefits

Components of Net Periodic Benefit Cost

(Thousands of dollars)	Three months ended Sept. 30, 2006 Pension Benefits	2005	2006 Postretirement Health Care Benefits	2005
Service cost	$ 15,406	$ 15,115	$ 1,659	$ 1,671
Interest cost	38,854	40,246	13,234	13,765
Expected return on plan assets	(67,017)	(70,290)	(6,690)	(6,425)
Amortization of transition obligation			3,611	3,645
Amortization of prior service cost (credit)	7,424	7,509	(544)	(545)
Amortization of net loss	4,339	1,705	6,200	6,562
Net periodic benefit cost (credit)	(994)	(5,715)	17,470	18,673
Credits not recognized due to the effects of regulation	3,159	4,842		
Additional cost recognized due to the effects of regulation			972	972
Net benefit cost (credit) recognized for financial reporting	$ 2,165	$ (873)	$ 18,442	$ 19,645

(Thousands of dollars)	Nine months ended Sept. 30, 2006 Pension Benefits	2005	2006 Postretirement Health Care Benefits	2005
Service cost	$ 46,220	$ 45,345	$ 4,975	$ 5,013
Interest cost	116,560	120,738	39,704	41,295
Expected return on plan assets	(201,049)	(210,048)	(20,068)	(19,275)
Amortization of transition obligation			10,833	10,934
Amortization of prior service cost (credit)	22,272	22,527	(1,634)	(1,634)
Amortization of net loss	13,015	5,115	18,598	19,685
Net periodic benefit cost (credit)	(2,982)	(16,323)	52,408	56,018
Credits not recognized due to the effects of regulation	9,477	14,526		
Additional cost recognized due to the effects of regulation			2,918	2,918
Net benefit cost (credit) recognized for financial reporting	$ 6,495	$ (1,797)	$ 55,326	$ 58,936

11. Segment Information

Xcel Energy has the following reportable segments: Regulated Electric Utility, Regulated Natural Gas Utility and All Other. 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 Sept. 30, 2006					
Operating revenues from external customers	$ 2,159,844	$ 230,293	$ 21,454	$	$ 2,411,591
Intersegment revenues	180	5,676		(5,856)	
Total revenues	$ 2,160,024	$ 235,969	$ 21,454	$ (5,856)	$ 2,411,591
Income (loss) from continuing operations	$ 223,368	$ (211)	$ 6,572	$ (5,554)	$ 224,175
Three months ended Sept. 30, 2005					

Operating revenues from external customers	$ 2,063,368	$ 207,220	$ 15,535	$	$ 2,286,123
Intersegment revenues	61	9,363		(9,424)	
Total revenues	$ 2,063,429	$ 216,583	$ 15,535	$ (9,424)	$ 2,286,123
Income (loss) from continuing operations	$ 189,848	$ (5,640)	$ 11,786	$ 1,823	$ 197,817

(Thousands of Dollars)	Regulated Electric Utility	Regulated Natural Gas Utility	All Other	Reconciling Eliminations	Consolidated Total
Nine months ended Sept. 30, 2006					
Operating revenues from external customers	$ 5,792,287	$ 1,519,423	$ 61,858	$	$ 7,373,568
Intersegment revenues	567	9,443		(10,010)	
Total revenues	$ 5,792,854	$ 1,528,866	$ 61,858	$ (10,010)	$ 7,373,568
Income (loss) from continuing operations	$ 427,102	$ 47,963	$ 35,289	$ (38,431)	$ 471,923
Nine months ended Sept. 30, 2005					
Operating revenues from external customers	$ 5,318,573	$ 1,368,622	$ 53,344	$	$ 6,740,539
Intersegment revenues	371	14,461		(14,832)	
Total revenues	$ 5,318,944	$ 1,383,083	$ 53,344	$ (14,832)	$ 6,740,539
Income (loss) from continuing operations	$ 353,988	$ 46,556	$ 28,472	$ (28,943)	$ 400,073

12. Subsequent Event

On Oct. 6, 2006, SPS issued $200 million of 10-year senior unsecured notes with a coupon rate of 5.6 percent and $250 million of 30-year senior unsecured notes with a coupon rate of 6 percent. Net proceeds, together with other available funds which may include short-term borrowings, will be used to pay at maturity $500 million of 5.125 percent senior notes due Nov. 1, 2006. Of the $500 million, $450 million was moved from current debt to long-term liabilities.

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

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

Except for the historical statements contained in this report, the matters discussed in the following discussion and analysis are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words anticipate, estimate, expect, objective, outlook, projected, possible, potential and similar expressions. Actua may vary materially. Factors that could cause actual results to differ materially include, but are not limited to:

Economic conditions, including inflation rates, monetary fluctuations and their impact on capital expenditures;

The risk of a significant slowdown in growth or decline in the U.S. economy, the risk of delay in growth recovery in the U.S. economy or the risk of increased cost for insurance premiums, security and other items as a consequence of past or future terrorist attacks;

Trade, monetary, fiscal, taxation and environmental policies of governments, agencies and similar organizations in geographic areas where Xcel Energy has a financial interest;

Customer business conditions, including demand for their products or services and supply of labor and materials used in creating their products and services;

Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission (SEC), the Federal Energy Regulatory Commission and similar entities with regulatory oversight;

Availability or cost of capital such as changes in: interest rates; market perceptions of the utility industry, Xcel Energy or any of its subsidiaries; or security ratings;

Factors affecting utility and nonutility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, maintenance or repairs; unanticipated changes to fossil fuel, nuclear fuel or natural gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; nuclear or environmental incidents; or electric transmission or gas pipeline constraints;

Employee workforce factors, including loss or retirement of key executives, collective bargaining agreements with union employees, or work stoppages;

Increased competition in the utility industry or additional competition in the markets served by Xcel Energy and its subsidiaries;

State, federal and foreign legislative and regulatory initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the electric and natural gas markets; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;

Rate-setting policies or procedures of regulatory entities, including environmental externalities, which are values established by regulators assigning environmental costs to each method of electricity generation when evaluating generation resource options;

Nuclear regulatory policies and procedures, including operating regulations and spent nuclear fuel storage;

Social attitudes regarding the utility and power industries;

Risks associated with the California power and other western markets;

Cost and other effects of legal and administrative proceedings, settlements, investigations and claims;

Technological developments that result in competitive disadvantages and create the potential for impairment of existing assets;

Risks associated with implementations of new technologies;

Other business or investment considerations that may be disclosed from time to time in Xcel Energy s SEC filings or in other publicly disseminated written documents; and

The other risk factors listed from time to time by Xcel Energy in reports filed with the SEC, including Risk Factors in Item 1A of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005 and Exhibit 99.01 to this report on Form 10-Q for the quarter ended Sept. 30, 2006.

RESULTS OF OPERATIONS

Summary of Financial Results

The following table summarizes the earnings contributions of Xcel Energy s business segments on the basis of GAAP. Continuing operations consist of the following:

regulated utility subsidiaries, operating in the electric and natural gas segments; and

several nonregulated subsidiaries and the holding company, where corporate financing activity occurs.

Discontinued operations consist of the following:

Quixx, which was classified as held for sale in the third quarter of 2005 based on a decision to divest this investment;

UE, which was sold in April 2005;

Seren, a portion of which was sold in November 2005 with the remainder sold in January 2006; and

CLF&P, which was sold in January 2005.

See Note 2 to the consolidated financial statements for a further discussion of discontinued operations.

Contribution to Earnings (Millions of dollars)	Three months ended Sept. 30, 2006	2005	Nine months ended Sept. 30, 2006	2005
GAAP income (loss) by segment				
Regulated electric utility segment income continuing operations	$ 223.4	$ 189.8	$ 427.1	$ 354.0
Regulated natural gas utility segment income continuing operations	(0.2)	(5.6)	48.0	46.6
Other utility results (a)	4.4	10.0	16.5	22.8
Utility segment income continuing operations	227.6	194.2	491.6	423.4
Holding company and other costs (a)	(3.4)	3.6	(19.7)	(23.3)
Income continuing operations	224.2	197.8	471.9	400.1
Regulated utility income discontinued operations	1.1		2.2	0.2
Other nonregulated income discontinued operations	(0.8)	(1.8)	(0.1)	0.6
Income discontinued operations	0.3	(1.8)	2.1	0.8
Total GAAP income	$ 224.5	$ 196.0	$ 474.0	$ 400.9

	Three months ended Sept. 30, 2006	2005	Nine months ended Sept. 30, 2006	2005
GAAP earnings per share contribution by segment (a)				
Regulated electric utility segment continuing operations	0.52	$ 0.45	$ 1.00	$ 0.83
Regulated natural gas utility segment continuing operations		(0.01)	0.11	0.11
Other utility results (b)	0.01	0.02	0.04	0.05
Utility segment earnings per share continuing operations	0.53	0.46	1.15	0.99
Holding company and other costs (b)		0.01	(0.03)	(0.03)
Earnings per share continuing operations	0.53	0.47	1.12	0.96
Regulated utility earnings discontinued operations				
Other nonregulated earnings discontinued operations				
Earnings per share discontinued operations				
Total GAAP earnings per share - diluted	$ 0.53	$ 0.47	$ 1.12	$ 0.96

(a) The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment but rather represents a direct equity interest in our assets and liabilities as a whole.

(b) Not a reportable segment. Included in All Other segment results in Note 11 to the consolidated financial statements. Other utility results, included in the earnings contribution table above, include certain subsidiaries of the utility operating companies that conduct non-utility activities. The largest of these other utility businesses is PSRI, a subsidiary of PSCo that owns and manages life insurance policies for PSCo employees and retirees.

The following table summarizes significant components contributing to the changes in the three months and nine months ended Sept. 30, 2006 earnings per share compared with the same period in 2005, which are discussed in more detail later.

Increase (decrease)	Three months ended Sept. 30, 2006 vs. 2005	Nine months ended Sept. 30, 2006 vs. 2005
2005 Earnings per share diluted	**$ 0.47**	**$ 0.96**
Components of change 2006 vs. 2005		
Higher base electric utility margins	0.08	0.28
Higher natural gas margins	0.02	0.03
Lower short-term wholesale and commodity trading margins		(0.05)
Higher depreciation and amortization expense	(0.03)	(0.06)
Higher operating and maintenance expense	(0.02)	(0.07)
Other	0.01	0.03
Net change in earnings per share continuing operations	**0.06**	**0.16**
Changes in Earnings Per Share Discontinued Operations		
2006 Earnings per share diluted	**$ 0.53**	**$ 1.12**

Utility Segment Results

Increased earnings for the third quarter of 2006 were primarily due to stronger base electric and natural gas utility margins. The stronger utility margins reflect weather-adjusted retail electric sales growth, electric and natural gas rate increases in various jurisdictions, as well as revenue associated with investments in MERP.

The following summarizes the estimated impact of weather on regulated utility earnings per share, based on estimated temperature variations from historical averages (excluding the impact on commodity trading operations):

	Three months ended Sept. 30,			Nine months ended Sept. 30,		
	2006 vs. Normal	**2005 vs. Normal**	**2006 vs. 2005**	**2006 vs. Normal**	**2005 vs. Normal**	**2006 vs. 2005**
Firm natural gas	$ 0.01	$ 0.00	$ 0.01	$ (0.02)	$ (0.01)	(0.01)
Retail electric	$ 0.03	$ 0.04	$ (0.01)	$ 0.05	$ 0.05	$ 0.00
Total	$ 0.04	$ 0.04	$ 0.00	$ 0.03	$ 0.04	$ (0.01)

Other Results Holding Company and Other Costs

Financing Costs and Preferred Dividends Holding company results include interest expense and preferred dividend costs, which are incurred at the Xcel Energy and intermediate holding company levels and are not directly assigned to individual subsidiaries.

Discontinued Operations

Discontinued Utility Segments During 2004, Xcel Energy reached an agreement to sell its regulated electric and natural gas subsidiary, CLF&P. The sale was completed in January 2005.

Discontinued All Other In March 2005, Xcel Energy agreed to sell its non-regulated subsidiary, UE to Zachry.

In August 2005, Xcel Energy s board of directors approved management s plan to pursue the sale of Quixx Corp., a former subsidiary of UE that partners in cogeneration projects, that was not included in the sale of UE to Zachry. In October 2006, a definitive agreement was reached for the sale of Quixx s interest in Borger Energy Associates and Quixx Power Services, Inc. to affiliates of Energy Investors Funds.

On Sept. 27, 2004, Xcel Energy s board of directors approved management s plan to pursue the sale of Seren, a wholly owned broadband communications services subsidiary. Seren delivers cable television, high-speed Internet and telephone service. In November 2005, Xcel Energy sold Seren s California assets to WaveDivision Holdings, LLC. In January 2006, Xcel Energy sold Seren s Minnesota assets to Charter Communications.

Income Statement Analysis Third Quarter 2006 vs. Third Quarter 2005

Electric Utility, Short-term Wholesale and Commodity Trading Margins

Electric fuel and purchased power expenses tend to vary with changing retail and wholesale sales requirements and unit cost changes in fuel and purchased power. Due to fuel and purchased energy cost-recovery mechanisms for customers in several states, most fluctuations in these costs do not materially affect electric utility margin.

Xcel Energy has two distinct forms of wholesale sales: short-term wholesale and commodity trading. Short-term wholesale refers to energy-related purchase and sales activity, and the use of certain financial instruments associated with the fuel required for, and energy produced from, Xcel Energy s generation assets or the energy and capacity purchased to serve native load. Commodity trading is not associated with Xcel Energy s generation assets or the energy and capacity purchased to serve native load. Short-term wholesale and commodity trading activities are considered part of the electric utility segment.

Short-term wholesale and commodity trading margins reflect the estimated impact of regulatory sharing of margins, if applicable. Commodity trading revenues are reported net of related costs (i.e., on a margin basis) in the Consolidated Statements of Income. Commodity trading costs include purchased power, transmission, broker fees and other related costs.

The following table details the revenue and margin for base electric utility, short-term wholesale and commodity trading activities.

(Millions of dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Total
Three months ended Sept. 30, 2006				
Electric utility revenue (excluding commodity trading)	$ 2,089	$ 63	$	$ 2,152
Electric fuel and purchased power	(1,106)	(55)		(1,161)
Commodity trading revenue			185	185
Commodity trading costs			(177)	(177)
Gross margin before operating expenses	$ 983	$ 8	$ 8	$ 999
Margin as a percentage of revenue	47.1 %	12.7 %	4.3 %	42.7 %
Three months ended Sept. 30, 2005				
Electric utility revenue (excluding commodity trading)	$ 2,004	$ 61	$	$ 2,065
Electric fuel and purchased power	(1,078)	(43)		(1,121)
Commodity trading revenue			282	282
Commodity trading costs			(284)	(284)
Gross margin before operating expenses	$ 926	$ 18	$ (2)	$ 942
Margin as a percentage of revenue	46.2 %	29.5 %	(0.7)%	40.1 %

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the three months ended Sept. 30:

Base Electric Utility Revenue

(Millions of dollars)	2006 vs. 2005
NSP-Minnesota interim base rate changes, subject to refund	$ 35
Sales growth (excluding weather impact)	19
NSP-Wisconsin rate case	15
Firm wholesale	(13)
MERP rider	11
Quality of service obligations	10
Fuel and purchased power cost recovery	6
Transmission revenue	3
Estimated impact of weather	(2)
Other	1
Total base electric utility revenue increase	$ 85

Base Electric Utility Margin

Base electric utility margin, which are primarily derived from retail customer sales, increased approximately $57 million for the third quarter of 2006, compared with the same period in 2005. For more information, see the table below.

(Millions of dollars)	**2006 vs. 2005**
NSP-Minnesota interim base rate changes, subject to refund	$ 35
Transmission fee classification change	(21)
NSP-Wisconsin rate changes, including fuel and purchased power cost recovery	20
PSCo ECA incentive	(17)
Sales growth (excluding weather impact)	15
MERP rider	11
Quality of service obligations	10
Purchased capacity costs	4
Estimated impact of weather	(3)
Firm wholesale	1
Other	2
Total base electric utility margin increase	$ 57

The transmission fee classification changed from other operating and maintenance expenses-utility in 2005 to electric utility margin in 2006, with no impact on operating income or net income. The change resulted from an analysis conducted in conjunction with the expiration and renegotiation of certain transmission agreements, resulting in better alignment of reporting for such costs consistent with the MISO classification.

Short-term Wholesale and Commodity Trading Margins

Short-term wholesale and commodity trading margins remained the same for third quarter, compared with the same period in 2005.

Natural Gas Utility Margins

The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin.

	Three months ended Sept. 30,	
(Millions of dollars)	**2006**	**2005**
Natural gas utility revenue	$ 230	$ 207
Cost of natural gas sold and transported	(137)	(127)
Natural gas utility margin	$ 93	$ 80

The following summarizes the components of the changes in natural gas revenue and margin for the three months ended Sept. 30:

Natural Gas Revenue

(Millions of dollars)	**2006 vs. 2005**
Purchased gas adjustment clause recovery	$ 4
Estimated impact of weather	4
Base rate changes all jurisdictions	10
Other	5
Total natural gas revenue increase	$ 23

Natural Gas Margin

(Millions of dollars)	**2006 vs. 2005**
Base rate changes all jurisdictions	$ 10

Transportation		2
Estimated impact of weather		2
Sales decline, excluding weather impact		(2)
Other		1
Total natural gas margin increase	$	13

Non-Fuel Operating Expense and Other Costs

Other Operating and Maintenance Expenses Utility Other operating and maintenance expenses for the third quarter of 2006 increased $10 million, or 2.6 percent, compared with the same period in 2005. The increase was primarily due to higher performance-based employee benefit costs for the quarter based on year-to-date results, and higher nuclear and combustion/hydro plant costs. Partially offsetting the increase was the reporting change of year-to-date transmission expense to electric margin previously discussed, which had no impact on net income. For more information see the following table.

(Millions of Dollars)	Three months ended Sept. 30, 2006 vs. 2005
Higher employee benefit costs, primarily performance-based	$ 21
Transmission fees classification change	(21)
Higher nuclear plant operating costs	6
Higher combustion/hydro plant costs	6
Higher consulting costs	3
Higher nuclear plant outage costs	2
Lower conservation incentive program costs	(1)
Other, including fleet transportation costs, facilities costs and information technology costs	(6)
Total other operating and maintenance expense increase	$ 10

Depreciation and Amortization Depreciation and amortization expense increased by approximately $19 million, or 9.9 percent, for the third quarter compared with the same period in 2005. The increase was due to normal plant additions and an approved change in decommissioning accruals, which resulted in an additional depreciation expense of $5.2 million.

Income taxes Income taxes for continuing operations increased by $22.4 million for the third quarter of 2006, compared with 2005. The increase in income tax expense was primarily due to an increase in pretax income. Income tax expense was partially offset by the reversal of a $9.8 million regulatory reserve in the third quarter 2006 and by recognition of research and experimentation credits and net operating loss carry back claims of $10.4 million in the third quarter 2005. The effective tax rate for continuing operations was 27.0 percent for the third quarter of 2006, compared with 23.5 percent for the same period in 2005. The increase in the effective tax rate was primarily due to an increase in the forecasted annual effective tax rate for 2006 as compared to 2005. Without the additional tax benefits, the effective tax rate would have been 30.2 percent in the third quarter 2006 and 27.5 percent in the third quarter 2005.

Income Statement Analysis First Nine Months of 2006 vs. First Nine Months of 2005

Electric Utility, Short-term Wholesale and Commodity Trading Margins

The following table details the revenue and margin for base electric utility, short-term wholesale and commodity trading activities.

(Millions of Dollars)	Base Electric Utility	Short-Term Wholesale	Commodity Trading	Consolidated Total
Nine months ended Sept. 30, 2006				
Electric utility revenue (excluding commodity trading)	$ 5,644	$ 134	$	$ 5,778
Electric fuel and purchased power	(2,989)	(118)		(3,107)
Commodity trading revenue			520	520
Commodity trading costs			(506)	(506)
Gross margin before operating expenses	$ 2,655	$ 16	$ 14	$ 2,685
Margin as a percentage of revenue	47.0%	11.9%	2.7%	42.6%

Nine months ended Sept. 30, 2005				
Electric utility revenue (excluding commodity trading)	$ 5,162	$ 153	$	$ 5,315
Electric fuel and purchased power	(2,700)	(95)		(2,795)
Commodity trading revenue			513	513
Commodity trading costs			(509)	(509)
Gross margin before operating expenses	$ 2,462	$ 58	$ 4	$ 2,524
Margin as a percentage of revenue	47.7%	37.9%	0.8%	43.3%

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the nine months ended Sept. 30:

Base Electric Utility Revenue

(Millions of dollars)		2006 vs. 2005
Fuel and purchased power cost recovery	$	229
NSP-Minnesota interim base rate changes, subject to refund		98
Sales growth (excluding weather impact)		43
MERP rider		29
Firm wholesale		24
NSP-Wisconsin rate changes		22
Quality of service obligations		16
Conservation and non-fuel rider revenue		12
Other		9
Total base electric utility revenue increase	$	482

Base Electric Utility Margin

Base electric utility margin increased approximately $193 million for the first nine months of 2006, compared with the same period in 2005. For more information, see the table below.

(Millions of dollars)		2006 vs. 2005
NSP-Minnesota interim base rate changes, subject to refund	$	98
NSP-Wisconsin rate changes, including fuel and purchased power cost recovery		39
Sales growth (excluding weather impact)		37
MERP rider		29
Transmission fee classification change		(19)
Firm wholesale		18
PSCo ECA incentive		(18)
Quality of service obligations		16
Purchased capacity costs		2
Other, including miscellaneous revenue and fuel handling		(9)
Total base electric utility margin increase	$	193

The transmission fee classification changed from other operating and maintenance expenses-utility in 2005 to electric utility margin in 2006, with no impact on operating income or net income. The change resulted from an analysis conducted in conjunction with the expiration and renegotiation of certain transmission agreements, resulting in better alignment of reporting for such costs consistent with the MISO classification.

Short-term Wholesale and Commodity Trading Margins

As expected, short-term wholesale margins declined for the first nine months of 2006, compared with the same period in 2005, due to retail sales growth, which reduced surplus generation available for sale in the wholesale market, decreased opportunities to sell due to the MISO centralized dispatch market, and the Minnesota rate case settlement agreement to refund to customers the majority of short-term wholesale margins attributable to Minnesota jurisdiction customers starting in 2006.

Natural Gas Utility Margins

The following table details the changes in natural gas utility revenue and margin. The cost of natural gas tends to vary with changing sales requirements and the unit cost of natural gas purchases. However, due to purchased natural gas cost recovery mechanisms for sales to retail customers, fluctuations in the cost of natural gas have little effect on natural gas margin.

	Nine Months Ended Sept. 30,	
(Millions of Dollars)	**2006**	**2005**
Natural gas utility revenue	$ 1,519	$ 1,369
Cost of natural gas sold and transported	(1,156)	(1,028)
Natural gas utility margin	$ 363	$ 341

The following summarizes the components of the changes in natural gas revenue and margin for the nine months ended Sept. 30:

Natural Gas Revenue

(Millions of dollars)	2006 vs. 2005
Purchased gas adjustment clause recovery	$ 154
Estimated impact of weather	(24)
Base rate changes all jurisdictions	23
Transportation	4
Sales decline - excluding weather impact	(3)
Other	(4)
Total natural gas revenue increase	$ 150

Natural Gas Margin

(Millions of dollars)	2006 vs. 2005
Base rate changes all jurisdictions	$ 23
Transportation	6
Estimated impact of weather	(5)
Sales decline (excluding weather impact)	(2)
Total natural gas margin increase	$ 22

Non-Fuel Operating Expense and Other Costs

Other Operating and Maintenance Expenses Utility Other operating and maintenance expenses for the first nine months of 2006 increased $49 million, or 3.9 percent, compared with the same period in 2005. Higher employee benefit costs, which are primarily performance-based, and higher nuclear and combustion/hydro plant costs were offset by lower nuclear plant outage costs and the transmission reporting change mentioned above. For more information see the following table:

(Millions of Dollars)	Nine months ended Sept. 30, 2006 vs. 2005
Higher employee benefit costs, primarily performance-based	$ 20
Lower nuclear plant outage costs	(19)
Transmission fees classification change	(19)
Higher nuclear plant operating costs	19
Higher combustion/hydro plant costs	16
Higher consulting costs	7
Higher uncollectible receivable costs	7
Higher conservation incentive program costs	3
Other, including fleet transportation costs, brand sponsorship costs, facilities costs, and information technology costs	15

Total other operating and maintenance expense increase	$	49

Depreciation and Amortization Depreciation and amortization expense increased by approximately $40 million, or 6.9 percent, for the first nine months of 2006, compared with the same period in 2005. The increase was due to normal plant additions and an approved change in decommissioning accruals, which resulted in an additional depreciation expense of $15 million year-to-date.

Income taxes Income taxes for continuing operations increased by $26.7 million for the first nine months of 2006, compared with 2005. The increase in income taxes was primarily due to an increase in pretax income. The effective tax rate for continuing operations was 25.0 percent for the first nine months of 2006 and 24.6 percent for the first nine months of 2005. The increase in the effective tax rate was primarily due to an increase in the forecasted annual effective tax rate for 2006 as compared to 2005.

Factors Affecting Results of Continuing Operations

Fuel Supply and Costs

Increased fuel costs may occur for Xcel Energy due to current railroad contract negotiations. See a discussion of fuel supply and costs at Factors Affecting Results of Continuing Operations in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005. However, it currently is expected such costs will continue to be recovered through regulatory mechisms.

Regulation

For a general discussion of the MISO Day 2 market, various SPS regulatory proceedings and other jurisdictional rate proceedings, see Note 4 to the consolidated financial statements.

Environmental Matters

See a discussion of the Clean Air Interstate and Mercury Rules at Note 5 to the consolidated financial statements.

Tax Matters

See a discussion of tax matters associated COLI policies at Note 3 to the consolidated financial statements.

Critical Accounting Policies

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions, which all may be appropriate to use. In addition, the financial and operating environment also may have a significant effect, not only on the operation of the business, but on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed. Item 7, Management s Discussion and Analysis, in Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005, includes a list of accounting policies that are most significant to the portrayal of Xcel Energy s financial condition and results, and that require management s most difficult, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Pending Accounting Changes

FASB Interpretation No. 48 (FIN 48) In July 2006, the FASB issued FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109. FIN 48 prescribes a comprehensive financial statement model of how a company should recognize, measure, present and disclose uncertain tax positions that the company has taken or expects to take in its income tax returns. FIN 48 requires that only income tax benefits that meet the more likely than not recognition threshold be recognized or continue to be recognized on its effective date. Initial derecognition amounts would be reported as a cumulative effect of a change in accounting principle.

FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. Xcel Energy is assessing the impact of the new guidance on all of its open tax positions.

Statement of Financial Accounting Standards No. 157 Fair Value Measurements ***(SFAS No. 157)*** In September 2006, the FASB issued SFAS No. 157, which enhances existing guidance for measuring assets and liabilities using fair value. SFAS No. 157 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, not an entity-specific measurement, and sets out a fair value hierarchy with the highest priority being quoted prices in active markets. Under SFAS No. 157, fair value measurements are disclosed by level within that hierarchy. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after Nov. 15, 2007. Xcel Energy is evaluating the impact of SFAS No. 157 on its financial condition and results of operations.

Statement of Financial Accounting Standards No. 158 Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R) (SFAS No. 158) In September 2006, the FASB issued SFAS No. 158, which requires companies to fully recognize the funded status of each pension and other postretirement benefit plan as a liability or asset on their balance sheets with all unrecognized amounts to be recorded in other comprehensive income. Although Xcel Energy continues to evaluate the impact of the new pronouncement, preliminary estimates indicate that assets could be increased by approximately $453 million, other comprehensive income could be credited by approximately $103 million and liabilities could be increased by approximately $350 million. Xcel Energy is evaluating regulatory accounting treatment, which would allow recognition of this item as a regulatory asset rather than as a charge to accumulated other comprehensive income. These estimates reflect the expected deferral of these amounts as regulatory assets or liabilities. The actual impact of the adoption of SFAS No. 158 could differ significantly from this estimate due to plan asset performance for the year and the discount rate in effect at the end of the year when the plans liabilities are measured. The implementation of SFAS No.158 will have no impact on net income. SFAS No. 158 is effective as of the end of the fiscal year ending after Dec. 15, 2006.

Financial Market Risks

Xcel Energy and its subsidiaries are exposed to market risks, including changes in commodity prices and interest rates, as disclosed in Management s Discussion and Analysis in its Annual Report on Form 10-K for the year ended Dec. 31, 2005. Commodity price risks for Xcel Energy s regulated subsidiaries are mitigated in most jurisdictions due to cost-based rate recovery regulation. At Sept. 30, 2006, there were no material changes to the financial market risks that affect the quantitative and qualitative disclosures presented as of Dec. 31, 2005, in Item 7A of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005. Value-at-risk, commodity trading and hedging information is provided below for informational purposes.

NSP-Minnesota maintains trust funds, as required by the Nuclear Regulatory Commission, to fund certain costs of nuclear decommissioning. Those investments are exposed to price fluctuations in equity markets and changes in interest rates. However, because the costs of nuclear decommissioning are recovered through NSP-Minnesota rates, fluctuations in investment fair value do not affect NSP-Minnesota s consolidated results of operations.

Xcel Energy s short-term wholesale and commodity trading operations measure the outstanding risk exposure to price changes on transactions, contracts and obligations that have been entered into, but not closed, using an industry standard methodology known as Value-at-Risk (VaR). VaR expresses the potential change in fair value on the outstanding transactions, contracts and obligations over a particular period of time, with a given confidence interval under normal market conditions. Xcel Energy utilizes the variance/covariance approach in calculating VaR. The VaR model employs a 95-percent confidence interval level based on historical price movements, lognormal price distribution assumption, delta half-gamma approach for non-linear instruments and a three-day holding period for both electricity and natural gas.

As of Sept. 30, 2006, the VaRs for the commodity trading operations were:

(Millions of Dollars)	Period Ended Sept. 30, 2006	Change from Period Ended June 30, 2006	VaR Limit	Average	High	Low
Commodity Trading (1)	$ 1.55	$ (0.14)	$ 5.00	$ 1.55	$ 2.15	$ 0.93

(1) Comprises transactions for NSP-Minnesota, PSCo and SPS.

Commodity Trading and Hedging Activities

Xcel Energy and its subsidiaries engage in short-term wholesale and commodity trading activities that are accounted for in accordance with SFAS No. 133. Xcel Energy and its subsidiaries make wholesale purchases and sales of energy and energy-related products and natural gas in order to optimize the value of their electric generating facilities and retail supply contracts. Xcel Energy also engages in limited commodity trading activities. Xcel Energy utilizes various physical and financial contracts and instruments for the purchase and sale of energy, energy-related products, capacity, natural gas, transmission and natural gas transportation.

For the period ended Sept. 30, 2006, these contracts and instruments, with the exception of transmission and natural gas transportation contracts, which meet the definition of a derivative in accordance with SFAS No. 133 were marked to market. Changes in fair value of commodity trading contracts that do not qualify for hedge accounting treatment are recorded in income in the reporting period in which they occur.

The changes to the fair value of the commodity trading contracts for the nine months ended Sept. 30, 2006 and 2005 were as follows (the commodity trading activity presented in the tables below also includes certain positions within the short-term wholesale activity which do not qualify for hedge accounting):

	Nine months ended Sept. 30,	
(Millions of Dollars)	**2006**	**2005**
Fair value of contracts outstanding at Jan. 1	$ 3.9	$
Contracts realized or otherwise settled during the period	(8.5)	(6.3)
Fair value of trading contract additions and changes during the period	16.9	4.2
Fair value of contracts outstanding at Sept. 30	$ 12.3	$ (2.1)

As of Sept. 30, 2006, the sources of fair value of the commodity trading and hedging net assets are as follows:

Commodity Trading Contracts

(Thousands of Dollars)	Source of Fair Value	Futures/Forwards Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ 2	$	$	$	$ 2
	2	1,123	1,051	505		2,679
PSCo	1	1,618				1,618
	2	1,498	1,586	121		3,205
Total Futures/Forwards Fair Value		$ 4,241	$ 2,637	$ 626	$	$ 7,504

(Thousands of Dollars)	Source of Fair Value	Options Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$ 6,897	$	$	$	$ 6,897
PSCo	2	(1,757)	(392)			(2,149)
Total Options Fair Value		$ 5,140	$ (392)	$	$	$ 4,748

Commodity Hedge Contracts

(Thousands of Dollars)	Source of Fair Value	Futures/Forwards Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Futures/ Forwards Fair Value
NSP-Minnesota	1	$ (68)	$	$	$	$ (68)
	2	27,232				27,232
PSCo	1	(137)				(137)
NSP-Wisconsin	1	(356)				(356)
Total Futures/Forwards Fair Value		$ 26,671	$	$	$	$ 26,671

(Thousands of Dollars)	Source of Fair Value	Options Maturity Less Than 1 Year	Maturity 1 to 3 Years	Maturity 4 to 5 Years	Maturity Greater Than 5 Years	Total Options Fair Value
NSP-Minnesota	2	$ (8,628)	$ 91	$	$	$ (8,537)
PSCo	2	(49,279)	1,111			(48,168)
NSP-Wisconsin	2	(2,116)				(2,116)
Total Options Fair Value		$ (60,023)	$ 1,202	$	$	$ (58,821)

(1) Prices actively quoted or based on actively quoted prices.

(2) Prices based on models and other valuation methods.

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

Normal purchases and sales transactions, as defined by SFAS No. 133, as amended, and certain other long-term power purchase contracts are not included in the fair values by source tables as they are not included in the commodity trading operations and are not qualifying hedges.

At Sept. 30, 2006, a 10-percent increase in market prices over the next 12 months for trading contracts would increase pretax income from continuing operations by approximately $1.5 million, whereas a 10-percent decrease would decrease pretax income from continuing operations by approximately $2.1 million.

Interest Rate Risk

Xcel Energy and its subsidiaries are subject to the risk of fluctuating interest rates in the normal course of business. Xcel Energy s policy allows interest rate risk to be managed through the use of fixed rate debt, floating rate debt and interest rate derivatives such as swaps, caps, collars and put or call options.

At Sept. 30, 2006, a 100-basis-point change in the benchmark rate on Xcel Energy s variable rate debt would impact pretax interest expense by approximately $5.8 million annually, or approximately $1.5 million per quarter. See Note 7 to the consolidated financial statements for a discussion of Xcel Energy and its subsidiaries interest rate swaps.

Credit Risk

Xcel Energy and its subsidiaries are exposed to credit risk. Credit risk relates to the risk of loss resulting from the nonperformance by a counterparty of its contractual obligations. Xcel Energy and its subsidiaries maintain credit policies intended to minimize overall credit risk and actively monitor these policies to reflect changes and scope of operations.

Xcel Energy and its subsidiaries conduct standard credit reviews for all counterparties. Xcel Energy employs additional credit risk control mechanisms when appropriate, such as letters of credit, parental guarantees, standardized master netting agreements and termination provisions that allow for offsetting of positive and negative exposures. The credit exposure is monitored and, when necessary, the activity with a specific counterparty is limited until credit enhancement is provided.

At Sept. 30, 2006, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $22.6 million, while a decrease of 10-percent would have resulted in a decrease of $15.8 million.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

(Millions of Dollars)	Nine months ended Sept. 30, 2006		2005	
Cash provided by operating activities				
Continuing operations	$	1,466	$	1,152
Discontinued operations		130		158
Total	$	1,596	$	1,310

Cash provided by operating activities for continuing operations increased by $314 million for the first nine months of 2006, compared with the first nine months of 2005. The increase is primarily due to the timing of working capital activity. Specifically, the collection of receivables and the collection of recoverable purchased natural gas and electric energy costs increased in 2006. The increase in cash provided by operations was partially offset by increased cash expenditures for accounts payable.

(Millions of Dollars)	Nine months ended Sept.30, 2006	2005
Cash provided by (used in) investing activities		
Continuing operations	$ (1,153)	$ (940)
Discontinued operations	42	72
Total	$ (1,111)	$ (868)

Cash used in investing activities for continuing operations increased by $213 million for the first nine months of 2006, compared with the first nine months of 2005. The increase was primarily due to increased capital expenditures. In addition, the cash flow used in investing activities reflects the sale of certain investments in the nuclear decommissioning trust fund and the reinvestment of the proceeds. The sale and reinvestment was part of a transaction intended to consolidate trust fund accounts into an income tax advantaged fund, resulting from the Energy Policy Act of 2005.

(Millions of Dollars)	Nine months ended Sept. 30, 2006	2005
Cash used in financing activities		
Continuing operations	$ (547)	$ (277)
Discontinued operations		
Total	$ (547)	$ (277)

Cash used in financing activities for continuing operations increased by $270 million for the first nine months of 2006, compared with the first nine months of 2005. The increase is due to increased repayments of short-term borrowings, partially offset by net proceeds from the issuance of long-term debt.

Capital Requirements

The capital expenditure programs of Xcel Energy are subject to continuing review and modification. Actual utility construction expenditures may vary from the estimates due to changes in electric and natural gas projected load growth, the desired reserve margin and the availability of purchased power, as well as alternative plans for meeting Xcel Energy s long-term energy needs. Plans for meeting future resource needs are subject to the review, potential modification and approval by regulatory agencies in the jurisdictions in which Xcel Energy operates. In addition, Xcel Energy s ongoing evaluation of compliance with future requirements to install emission-control equipment may have a significant impact on actual capital requirements.

The following is the consolidated Xcel Energy capital expenditure budget:

Project Description (Millions of Dollars)	2006	2007	2008	2009	2010
Base and other capital expenditures	$ 850	$ 850	$ 830	$ 990	$ 980
MERP	350	270	180	40	10
Comanche 3	200	340	280	60	10
Minnesota wind transmission	60	120	10	50	20
CapX 2020		10	20	110	240

Nuclear, including fuel, capacity increases and life extension		160		180		180		250		240
Total	$	1,620	$	1,770	$	1,500	$	1,500	$	1,500

The following is an update of the capital expenditure budget for each of the utility subsidiaries of Xcel Energy:

Utility Subsidiary (Millions of Dollars)		**2006**		**2007**		**2008**		**2009**		**2010**
NSP-Minnesota	$	910	$	880	$	680	$	810	$	820
NSP-Wisconsin		60		70		70		50		60
PSCo		550		680		620		510		500
SPS		100		140		130		130		120
Total	$	1,620	$	1,770	$	1,500	$	1500	$	1,500

CAPX 2020 - In June 2006, CapX 2020, an alliance of electric cooperatives, municipals and investor-owned utilities in the upper Midwest including Xcel Energy, announced that it had identified three groups of transmission projects that proposed to be complete by 2020**.** Group 1 project investments are expected to total approximately $1.3 billion, with major construction targeted to begin in 2009 or 2010 and ending three or four years later. Xcel Energy s investment is expected to be approximately $700 million. Approximately 75 percent of the capital expenditures and return on investment for transmission projects are expected to be recovered under an NSP-Minnesota transmission cost recovery tariff rider mechanism authorized by Minnesota legislation and pending MPUC approval. Similar transmission cost recovery mechanisms have been proposed in North Dakota and South Dakota. Cost recovery by NSP-Wisconsin is expected to occur through the biennial PSCW rate case process.

Nuclear Capacity Increases and Life Extension - In August 2004, Xcel Energy announced plans to pursue 20-year license renewals for the Monticello and Prairie Island nuclear plants, whose licenses will expire between 2010 and 2014. License renewal applications for Monticello were submitted to the Nuclear Regulatory Commission (NRC) and the MPUC in early 2005. License renewal is expected to be approved by the NRC in November 2006, and the MPUC issued its approval in October 2006 allowing additional spent fuel storage. The MPUC stayed the order until June 2007, following the Minnesota legislative session. Similar applications will be submitted for Prairie Island in 2008, with approval expected in 2010.

At the direction of the MPUC, Xcel Energy is pursuing capacity increases of all three units that will total approximately 250 megawatts, to be implemented, if approved, between 2009 and 2015. The life extension and a capacity increase for Prairie Island Unit 2 is contingent on replacement of Unit 2 s original steam generators, currently planned for replacement during the refueling outage in 2013. Total capital investment for these activities estimated to be approximately $1 billion between 2006 and 2015. Xcel Energy plans to seek approval for an alternative recovery mechanism from customers of its nuclear costs.

Capital Sources

Xcel Energy and Utility Subsidiary Credit Facilities - As of October 25, 2006, Xcel Energy had the following credit facilities available to meet its liquidity needs:

(Millions of Dollars)

Company		**Facility**		**Drawn***		**Available**		**Cash**		**Liquidity**	**Maturity**
NSP-Minnesota	$	450	$	28.1	$	421.9	$		$	421.9	April 2010
PSCo	$	600	$	201.0	$	399.0	$		$	399.0	April 2010
SPS	$	250	$	1.7	$	248.3	$	338.4	$	586.7	April 2010
Xcel Energy Holding Company	$	700	$	147.5	$	552.5	$	0.1	$	552.6	Nov. 2009
Total	$	2,000	$	378.3	$	1,621.7	$	338.5	$	1,960.2	

* Includes outstanding commercial paper and letters of credit

The liquidity table reflects the payment of common dividends on October 20, 2006.

NSP-Wisconsin has approval from the PSCW to borrow up to $75 million in short-term debt from either external financial institutions or NSP-Minnesota. Currently, NSP-Wisconsin borrows on a short-term basis through an inter-company borrowing agreement with NSP-Minnesota. At Sept. 30, 2006, NSP-Wisconsin had $4.3 million of short-term borrowings outstanding, under this borrowing agreement, and no cash.

Commercial Paper Xcel Energy, NSP-Minnesota, PSCo and SPS each have individual commercial paper programs. All four commercial paper programs are rated A-2 by Standard & Poor s Ratings Services and P-2 by Moody s Investor Services, Inc. A security rating is not a recommendation to buy, sell or hold securities and is subject to revision or withdrawal at any time by a rating agency. At Sept. 30, 2006, Xcel Energy, NSP-Minnesota, PSCo and SPS had $350.0 million of outstanding commercial paper at a weighted average yield of 5.43 percent.

Money Pool In 2003, Xcel Energy received SEC approval under the Public Utility Holding Company Act of 1935 (PUHCA) to establish a utility money pool arrangement with the utility subsidiaries, subject to receipt of required state regulatory approvals. This approval was also granted by the FERC in a July 18, 2006 order. The utility money pool allows for short-term loans between the utility subsidiaries and from the holding company to the utility subsidiaries at market-based interest rates. The utility money pool arrangement does not allow loans from the utility subsidiaries to the holding company. NSP-Minnesota, PSCo and SPS participate in the money pool pursuant to approval from their respective state regulatory commissions.

(Millions of Dollars)	Borrowings (Investments)	Total Borrowing Limits
NSP Minnesota	$ (10.7)	$ 250
PSCo	$ 32.4	$ 250
SPS	$	$ 100
Holding Company	$ (21.7)	$

Recent Financing Activity On Oct. 6, 2006, SPS issued $200 million of 10-year senior unsecured notes with a coupon of 5.6 percent and $250 million of 30-year senior unsecured notes with a coupon of 6 percent. Net proceeds, together with other available funds which may include short-term borrowings, will be used to pay at maturity $500 million of 5.125 percent senior notes due Nov. 1, 2006.

Concurrent with the closing of the senior notes offering, SPS terminated its $350 million unsecured credit agreement that had been entered into on Aug. 23, 2006 to provide available bridge financing to help fund repayment of the maturing long-term debt at SPS.

Future Financing Plans

Xcel Energy is in the process of syndicating new 5-year revolving credit agreements at Xcel Energy, PSCo, NSP-Minnesota and SPS having an aggregate principal amount of $2.25 billion. The proposed new separate credit agreements would provide for revolving credit availability of $800 million at Xcel Energy, $700 million at PSCo, $500 million at NSP-Minnesota and $250 million at SPS . The proposed new credit agreements would replace a $700 million revolving credit agreement at Xcel Energy maturing in November 2009; a $600 million revolving credit agreement maturing in April 2010 at PSCo; a $450 million revolving credit agreement maturing in April 2010 at NSP-Minnesota; and a $250 million revolving credit agreement maturing in April 2010 at SPS. The revolving credit agreements will provide backstop for commercial paper programs and provide for letters of credit.

Earnings Guidance

2006 Earnings Guidance Xcel Energy anticipates that its 2006 earnings per share from continuing operations will be in the upper half of the guidance range shown below. Key assumptions are detailed in the following table.

	2006 Diluted EPS Range
Utility operations	$1.25 - $1.35
COLI tax benefit	$0.10
Holding company financing costs and other	$(0.10)
Xcel Energy Continuing Operations EPS	**$1.25 - $1.35**

Key Assumptions for 2006:

Normal weather patterns are experienced for the remainder of the year;

Final Minnesota electric rate case results consistent with MPUC Sept. 1, 2006 order;

No material incremental accruals related to the SPS regulatory proceedings;

Weather-adjusted retail electric utility sales grow by approximately 1.8 percent to 2.1 percent;

Weather-adjusted retail natural gas utility sales decline by approximately 1.0 percent to 2.0 percent;

Short-term wholesale and commodity trading margins are within a range of $30 million to $40 million;

Utility operating and maintenance expenses increase approximately 4 percent from 2005 levels;

Depreciation expense increases approximately $45 million to $55 million, excluding decommissioning;

Decommissioning accruals increase approximately $20 million;

Interest expense increases approximately $10 million to $15 million from 2005 levels;

Allowance for funds used during construction recorded for equity financing increases approximately $5 million to $10 million from 2005 levels;

Xcel Energy continues to recognize corporate-owned life insurance tax benefits, which is currently being litigated with the Internal Revenue Service;

The effective tax rate for continuing operations is approximately 24 percent to 26 percent; and

Average common stock and equivalents total approximately 430 million shares, based on the If Converted method for convertible notes.

Xcel Energy s 2007 earnings per share from continuing operations guidance and key assumptions are detailed in the following table.

		2007 Diluted Earnings Per Share Range
Utility operations		$1.39 - $1.49
COLI tax benefit	$0.11	
Holding company financing costs and other		$(0.15)
Xcel Energy Continuing Operations		**$1.35 - $1.45**

Key Assumptions for 2007:

Normal weather patterns are experienced during the year;

Approval by the Colorado Commission of the settlement agreement in the Colorado electric rate case;

Final Minnesota electric rate case results consistent with MPUC Sept. 1, 2006 order;

Reasonable rate recovery is approved in the Texas electric rate case;

No material incremental accruals related to the SPS regulatory proceedings;

Weather-adjusted retail electric utility sales grow by approximately 1.7 percent to 2.2 percent;

Weather-adjusted retail natural gas utility sales decline by approximately 1.0 percent to 2.0 percent;

Short-term wholesale and commodity trading margins are within a range of $15 million to $25 million;

Capacity costs at NSP-Minnesota and SPS are projected to increase approximately $35 million. Capacity costs at PSCo are expected to be recovered under the PCCA;

Utility operating and maintenance expenses increase between 2 percent and 3 percent from 2006 levels;

Depreciation expense increases approximately $45 million to $55 million;

Interest expense increases approximately $35 million to $40 million from 2006 levels;

Allowance for funds used during construction recorded for equity financing increases approximately $17 million to $23 million from 2006 levels;

Xcel Energy continues to recognize corporate-owned life insurance tax benefits, which is currently being litigated with the Internal Revenue Service;

The effective tax rate for continuing operations is approximately 28 percent to 31 percent; and

Average common stock and equivalents total approximately 433 million shares, based on the If Converted method for convertible notes.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Item 2, Management s Discussion and Analysis Financial Market Risks.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

Internal Controls Over Financial Reporting

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

Part II OTHER INFORMATION

Item 1. Legal Proceedings

In the normal course of business, various lawsuits and claims have arisen against Xcel Energy. Management, after consultation with legal counsel, has recorded an estimate of the probable cost of settlement or other disposition for such matters. See Notes 3, 4 and 5 of the consolidated financial statements in this Quarterly Report on Form 10-Q for further discussion of legal proceedings, including Regulatory Matters and Commitments and Contingent Liabilities, which are hereby incorporated by reference. Reference also is made to Item 3 of Xcel Energy s Annual Report on Form 10-K for the year ended Dec. 31, 2005 and Note 14 of the consolidated financial statements in such Form 10-K for a description of certain legal proceedings presently pending. Except as discussed in Notes 3, 4 and 5 herein, there are no new significant cases to report against Xcel Energy, and there have been no notable changes in the previously reported proceedings.

Manufactured Gas Plant 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, on Oct. 28, 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. On Nov. 12, 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. Although the Wisconsin action has not been dismissed, the January 2007 trial date has been adjourned and has not been rescheduled.

NSP-Wisconsin has entered into confidential settlements with St. Paul Mercury Insurance Company, St. Paul Fire and Marine Insurance Company and the Phoenix Insurance Company (St. Paul Companies), Associated Electric & Gas Insurance Services Limited, Fireman s Fund Insurance Company, and INSCO, Ltd. (on its own behalf and on behalf of the insurance companies subscribing per Britamco, Ltd.) and these insurers have been dismissed from the Minnesota and Wisconsin actions. These settlements will not have a material effect on Xcel Energy s financial results.

NSP-Wisconsin has reached settlements in principle with Admiral Insurance Company; Allstate Insurance Co.; Compagnie Europeene D Assurances Industrielles S.A.; certain underwriters at Lloyd s, London and certain London Market Insurance Companies (London Market Insurers), General Reinsurance Corporation and First State and Twin City Fire Insurance Companies. These settlements are not expected to have a material effect on NSP-Wisconsin s financial results.

On Oct. 6, 2006, the trial court issued a memorandum and order on various summary judgment motions. The court ruled that Minnesota law on allocation applies and ordered dismissal, without prejudice, of 15 carriers whose coverage would not be triggered under such an allocation method. The court denied the insurers motions for summary judgment on the sudden and accidental and absolute pollution exclusions; late notice; legal expenses and costs; certain specific lost policies; and miscellaneous coverage issues under several individual policies. The court granted the motions of Fidelity and Casualty Insurance Company and Continental Insurance Company related to certain specific lost policies. On Oct. 13, 2006, the trial court denied NSP-Wisconsin s **request for leave to file** a motion for reconsideration of the court s allocation decision. The Nov. 6, 2006 trial date was also adjourned to **allow for additional discovery and potential motions in light of** the Minnesota Supreme Court s **recent allocation** decision in Wooddale Builders, Inc. v. Maryland Casualty Company, 2006 Minn. LEXIS 679 (Oct. 5, 2006). On Oct. 25, 2006, the court indicated that trial would be scheduled in July 2007.

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 operate as a credit to ratepayers, therefore, these lawsuits should not have a material effect on NSP-Wisconsin s financial results.

Cornerstone Propane Partners, L.P. et al. vs. e prime, inc. et al. On Feb. 2, 2004, a purported class action complaint was filed in the U.S. District Court for the Southern District of New York against e prime and three other defendants by Cornerstone Propane Partners, L.P., Robert Calle Gracey and Dominick Viola on behalf of a class who purchased or sold one or more New York Mercantile Exchange natural gas futures and/or options contracts during the period from Jan. 1, 2000, to Dec. 31, 2002. The complaint alleges that defendants manipulated the price of natural gas futures and options and/or the price of natural gas underlying those contracts in violation of the Commodities Exchange Act. In February 2004, the plaintiff requested that this action be consolidated with a similar suit involving Reliant Energy Services. In February 2004, defendants, including e prime, filed motions to dismiss. In September 2004, the U.S. District Court denied the motions to dismiss. On Jan. 25, 2005, plaintiffs filed a motion for class certification, which defendants opposed. On Sept. 30, 2005, the U.S. District Court granted plaintiffs motion for class certification. On Oct. 17, 2005, defendants filed a petition with the Second Circuit Court of Appeals challenging the class certification. On Dec. 5, 2005, e prime reached a tentative settlement with the plaintiffs that received final court approval in May 2006. The settlement was paid by e prime and it did not have a material financial impact on Xcel Energy.

Nuclear Waste Disposal Litigation The federal government has the responsibility to dispose of domestic spent nuclear fuel and other high-level radioactive substances. The Nuclear Waste Policy Act (the Act) requires the Department of Energy (DOE) to implement this disposal program. This includes the siting, licensing, construction and operation of a permanent repository for domestically produced spent nuclear fuel from civilian nuclear power reactors and other high-level radioactive substances. The Act and contracts between DOE and domestic utilities obligated DOE to begin to dispose of these materials by Jan. 31, 1998. The federal government has designated the site as Yucca Mountain in Nevada. The nuclear waste disposal program has resulted in extensive litigation.

On June 8, 1998, NSP-Minnesota filed a complaint in the U.S. Court of Federal Claims against the United States requesting breach of contract damages, past and as projected into the future, in excess of $1 billion for the DOE s failure to meet the 1998 deadline. NSP-Minnesota has demanded damages consisting of the added costs of storage of spent nuclear fuel at the Prairie Island and Monticello nuclear generating plants, costs related to the Private Fuel Storage, LLC and certain costs relating to the 1994 and 2003 state legislation relating to the storage of spent nuclear fuel at Prairie Island. On July 31, 2001, the Court granted NSP-Minnesota s motion for partial summary judgment on liability. A subsequent court decision determined that the utilities were precluded from making a claim for future damages, a utility could claim damages up to some point prior to the trial, and separate claims would have to be made in the future as damages accumulated. In response to this decision, NSP-Minnesota filed an amended complaint seeking damages through Dec. 31, 2004.

NSP-Minnesota currently claims total damages in excess of $100 million through Dec. 31, 2004 (damages after 2004 will be claimed in subsequent proceedings). A four week trial on the damages issue commenced on Oct. 24, 2006, the first two weeks of which will take place in Minneapolis, the final two weeks of which will take place in Washington, D.C. A decision will ultimately be rendered by Senior Judge Wiese of the Court of Federal Claims.

On July 9, 2004, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision in consolidated cases challenging regulations and decisions on the federal nuclear waste program. The Court of Appeals rejected challenges by the state of Nevada and other intervenors with respect to most of the NRC s challenged repository licensing regulations, the congressional resolution approving Yucca Mountain as the site of the permanent repository, and the DOE and presidential actions leading to the approval of the Yucca Mountain site. The Court of Appeals vacated the 10,000 year compliance period adopted by EPA regulations governing spent nuclear fuel disposal at Yucca Mountain and incorporated in the NRC regulations. Xcel Energy has not ascertained the impact of the decision on its nuclear operations and storage of spent nuclear fuel; however, the decision may result in additional delay and uncertainty around disposal of spent nuclear fuel. In July 2006 the Office of Civilian Radioactive Waste Management indicated that under the best achievable repository construction schedule , Yucca Mountain would be able to begin accepting spent nuclear fuel in March 2017.

Polychlorinated Biphenyl (PCB) Storage and Disposal In August 2004, Xcel Energy received notice from the EPA contending SPS violated PCB storage and disposal regulations with respect to storage of a drained transformer and related solids. The EPA contended the fine for the alleged violation was approximately $1.2 million. Xcel Energy contested the fine and submitted a voluntary disclosure to the EPA. On April 17, 2006, SPS received a notice of determination from the

EPA stating that the voluntary disclosure had been reviewed and that SPS had met all conditions of the EPA s audit policy. Accordingly, the EPA will mitigate 100 percent of the gravity-based penalty for the disclosed violation, and no economic penalty will be assessed.

Department of Labor Audit In 2001, Xcel Energy received notice from the U.S. Department of Labor (DOL) Employee Benefit Security Administration that it intended to audit the Xcel Energy pension plan. After multiple on-site meetings and interviews with Xcel Energy personnel, the DOL indicated on Sept. 18, 2003, that it was prepared to take the position that Xcel Energy, as plan sponsor and through its delegate, the Pension Trust Administration Committee, breached its fiduciary duties under ERISA with respect to certain investments made in limited partnerships and hedge funds in 1997 and 1998. The DOL has offered to conclude the audit if Xcel Energy is willing to contribute to the plan the full amount of losses from the questioned investments, or approximately $7 million. On July 19, 2004, Xcel Energy formally responded with a letter to the DOL that asserted no fiduciary violations have occurred and extended an offer to meet to discuss the matter further. In 2005, and again in January 2006, the DOL submitted two additional requests for information related to the investigation, and Xcel Energy submitted timely responses to each request.

On June 12, 2006, the DOL issued a letter to the Xcel Energy Pension Trust Administration Committee indicating that, although there may have been a breach of the Committee s fiduciary obligations under ERISA, the DOL will not pursue any action against the Committee or the pension plan with respect to these alleged breaches due, in part, to the steps the Committee has taken in outsourcing certain investment management and administration functions to third parties.

NewMech vs. Northern States Power Company On May 16, 2006, NewMech served and filed a complaint against NSP-Minnesota, Southern Minnesota Municipal Power Agency (SMMPA), and Benson Engineering in the Minnesota State District Court, Sherburne County, alleging entitlement to payment in the amount of approximately $4.2 million for unpaid costs allegedly associated with construction work done by NewMech at NSP-Minnesota and SMMPA s jointly owned Sherco 3 generating plant in 2005. NewMech had previously served a mechanic s lien, and sought, through this action, foreclosure of the lien and sale of the property. NewMech additionally sought the claimed damages as a result of an alleged breach of contract by NSP-Minnesota. NSP-Minnesota, SMMPA and Benson filed answers denying NewMech s allegations. Additionally, NSP-Minnesota and SMMPA counterclaimed for damages in excess of $7 million for breach of contract, delay in contract performance, misrepresentation and fraudulent inducement to enter into the contract and slander of title. A confidential settlement of the dispute was reached on Sept. 29, 2006 and it did not have a material financial impact on Xcel Energy.

Item 1A. Risk Factors

Xcel Energy s are documented in Item 1A of Part I of its 2005 Annual Report on Form 10-K, which is incorporated herein by reference. There have been no material changes to the risk factors.

Item 5. Other Information

Revisions to Perquisite Policy for Executives - On Oct. 25, 2006, the Xcel Energy Inc. Board of Directors approved changes in Xcel Energy policy regarding perquisites for executives, effective on Jan. 1, 2007.

Under the prior policy, each senior executive was provided an annual cash allowance ($18,000 for officers and $9000 for business unit vice presidents), and the opportunity to be reimbursed for certain expenses including annual physical exam, annual financial planning services, club dues and a home security system. In addition, senior executives were offered the opportunity to participate in an executive medical benefits plan, and an executive life insurance plan in lieu of the medical and life insurance plans offered to other Xcel Energy Inc. employees.

Effective Jan. 1, 2007, the executive medical and executive life insurance plans will be eliminated for all active executive-level employees and the executives will be eligible to participate in the group medical and group term life insurance plans offered by Xcel Energy to other employees. In addition, rather than allowing reimbursements for specified perquisites, the new policy will provide each executive with a cash allowance, ranging from $9500 annually for business unit vice presidents to $30,000 annually for the Chief Executive Officer. The executives will then have the discretion to apply any or all amounts toward a specific perquisite, a combination of perquisites or, alternatively, to take the entire amount in cash.

Amendments to Senior Executive Severance and Change in Control Policy - On Oct. 25, 2006, the Xcel Energy Inc. Board of Directors approved amendments to the Xcel Energy Senior Executive Severance and Change in Control Policy (the Policy) effective Jan. 1, 2007. Under the terms of the Policy, these amendments will apply to current participants only to the extent they provide Xcel Energy written consent to such change prior to Jan. 1, 2007.

Under the pre-amendment terms of the Policy, if an executive was terminated other than for cause, due to death, disability, retirement, qualified sale of a business or voluntarily, he or she would be entitled to severance benefits including the following:

a cash payment equal to two times the participant s annual base salary and target annual incentive award;

prorated target annual incentive compensation for the year of termination;

financial planning benefit for two years and outplacement services costing not more than $30,000;

a cash payment equal to value of the additional amounts that would have been credited to or paid on behalf of the participant under pension and retirement savings plans, if the participant had remained employed for another two years;

continued medical, dental and life insurance benefits for two years; and

continued perquisite allowance for two years.

If the participant is terminated, including a voluntary termination following a diminution in salary, benefits or responsibilities, within two years following a change in control (as defined in the Policy), the participant will receive benefits under the Policy similar to the severance benefits above, except that for certain of our executive officers, including those of our named executive officers who are participants, the cash payment will be equal to three times the participant s annual base salary and target annual incentive award, the cash payment for the value of additional retirement savings and pension credits will be for three years instead of two and medical, dental and life insurance, financial planning and perquisite allowance benefits will be continued for three years instead of two. In addition, each of the participants entitled to enhanced benefits upon a change-in-control will be entitled to receive an additional cash payment to make the participant whole for any excise tax on excess parachute payments that he or she may incur, with certain limitations specified in the Policy

Effective Jan. 1, 2007 for those participants who provide Xcel Energy with written consent prior to such date, the Policy will be amended to decrease the severance multiple for non-change-in-control terminations from two times to one time annual base salary and target annual incentive award, the cash payment for the value of additional retirement savings and pension credits will be for one year instead of two years and medical, dental and life insurance, financial planning and perquisite allowance benefits will be continued for one year instead of two years.

As indicated above, the amendment will only apply to those executives who provide Xcel Energy written consent. For those executives not giving consent, the original Policy terms will continue to apply.

Item 6. Exhibits

The following Exhibits are filed with this report:

4.01	Fourth Supplemental Indenture, dated October 1, 2006, between Southwestern Public Service Company (a New Mexico corporation) and The Bank of New York, as successor Trustee. (Exhibit 4.01 to SPS Form 8-K (file no. 001-03789) dated October 3, 2006).
31.01	Principal Executive Officer s and Principal Financial Officer s certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Statement pursuant to Private Securities Litigation Reform Act of 1995.

SIGNATURES

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

XCEL ENERGY INC.
(Registrant)

/s/ TERESA S. MADDEN
Teresa S. Madden
Vice President and Controller

/s/ BENJAMIN G.S. FOWKE III
Benjamin G.S. Fowke III
Vice President and Chief Financial Officer

Oct. 27, 2006