Control Number: 32766

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**SOAH DOCKET NO. 473-06-2536**
**DOCKET NO. 32766**

| | | |
|---|---|---|
| **APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR: (1) AUTHORITY TO CHANGE RATES; (2) RECONCILIATION OF ITS FUEL COSTS FOR 2004 AND 2005; (3) AUTHORITY TO REVISE THE SEMI-ANNUAL FORMULAE ORIGINALLY APPROVED IN DOCKET NO. 27751 USED TO ADJUST ITS FUEL FACTORS; AND (4) RELATED RELIEF** | § § § § § § § § § § § | **BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS** |

**SOUTHWESTERN PUBLIC SERVICE COMPANY'S RESPONSE TO AXM's ELEVENTH REQUEST FOR INFORMATION QUESTION NOS. 11-1 THROUGH 11-7**
(*Filename*: 10E2.doc; *Total Pages*: 59)


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**SOAH DOCKET NO. 473-06-2536**
**DOCKET NO. 32766**

| | | |
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| **APPLICATION OF SOUTHWESTERN PUBLIC SERVICE COMPANY FOR: (1) AUTHORITY TO CHANGE RATES; (2) RECONCILIATION OF ITS FUEL COSTS FOR 2004 AND 2005; (3) AUTHORITY TO REVISE THE SEMI-ANNUAL FORMULAE ORIGINALLY APPROVED IN DOCKET NO. 27751 USED TO ADJUST ITS FUEL FACTORS; AND (4) RELATED RELIEF** | § § § § § § § § § § § | **BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS** |

**SOUTHWESTERN PUBLIC SERVICE COMPANY'S RESPONSE TO AXM's ELEVENTH REQUEST FOR INFORMATION QUESTION NOS. 11-1 THROUGH 11-7**

Southwestern Public Service Company (SPS) files this response to AXM's Eleventh Request for Information.

## I. WRITTEN RESPONSES

SPS's written responses to the AXM's Eleventh Request for Information are attached and incorporated by reference. Each response is stated on or attached to a separate page on which the request has been restated. SPS's responses are made in the spirit of cooperation without waiving SPS's right to contest the admissibility of any of these matters at hearing. Pursuant to P.U.C. PROC. R. 22.144(c)(2)(A), each response lists the preparer or person under whose direct supervision the response was prepared and any sponsoring witness. When SPS provides certain information sought by the request while objecting to the provision of other information, it does so without prejudice to its objection in the interests of narrowing discovery disputes pursuant to P.U.C. PROC.

R. 22.144(d)(5). Pursuant to P.U.C. PROC. R. 22.144(c)(2)(F), SPS stipulates that its responses may be treated by all parties as if they were made under oath.

## II. INSPECTIONS.

If responsive documents are more than 100 pages but less than eight linear feet in length, the response will indicate that the attachment is VOLUMINOUS and, pursuant to P.U.C. PROC. R. 22.144(h)(2), the attachment will be made available for inspection at SPS's voluminous room at 1150 Capitol Center, 919 Congress Ave., Austin, Texas 78701, telephone number (512) 476-7137. If a response or the responsive documents are provided pursuant to the protective order in this docket, the response will indicate that it or the attachment is either CONFIDENTIAL or HIGHLY SENSITIVE as appropriate under the protective order. Highly sensitive responses will be made available for inspection at SPS's voluminous room, unless they form a part of a response that exceeds eight linear feet in length; then they will be available at their usual repository in accordance with the following paragraph. Please call in advance for an appointment to ensure that there is sufficient space to accommodate your inspection.

If responsive documents exceed eight linear feet in length, the response will indicate that the attachment is subject to the FREIGHT CAR DOCTRINE, and, pursuant to Commission Procedural Rule 22.144(h)(3), the attachment will be available for inspection at its usual repository, SPS's offices in Amarillo, Texas, unless otherwise indicated. SPS requests that parties wishing to inspect this material provide at least 48 hours' notice of their intent by contacting Steven D. Arnold of Hinkle, Hensley, Shanor & Martin, L.L.P., 1150 Capitol Center, 919 Congress Ave., Austin, Texas 78701; telephone number (512) 476-7137; facsimile transmission number (512) 476-7146. Inspections will be scheduled to accommodate all requests with as little inconvenience to the requesting party and to SPS's operations as possible.

Respectfully submitted,

XCEL ENERGY

Jerry F. Shackelford
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& BAILEY, L.L.P.

By: Amy M. Shelhamer
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email: ashelhamer@courtneylawfirm.com
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(806) 372-5569
(806) 372-9761 (FAX)

ATTORNEYS FOR SOUTHWESTERN
PUBLIC SERVICE COMPANY

## RESPONSES

### QUESTION NO. 11-1:

For the period from 2000 through 2006, please provide a copy of all prior testimony prepared by or for each witness who submitted testimony in this proceeding (Docket No. 32766) in any other regulatory or judicial proceeding.

### RESPONSE:

A hard copy of all prior testimony prepared by or for each witness in this proceeding would be subject to the FREIGHT CAR DOCTRINE as defined by the Commission's Procedural Rules. To provide greater access to the requested materials, SPS will provide the requested information electronically on CD to all parties. SPS requires additional time to prepare the CD and will supplement this response on August 11, 2006.

Preparer: Jeannette McFarlin
Sponsor: All witnesses

**QUESTION NO. 11-2:**

Regarding the recent property tax law changes enacted by the Texas Legislature in 2006, please explain how SPS is treating any property tax reductions it may experience as a result of those changes.

**RESPONSE:**

Refer to SPS's response to Question Nos. AG-3-21 to Staff's Third Request for Information and TIEC4-27.

Preparer: Paul Simon
Sponsor: Timothy L. Willemsen

**QUESTION NO. 11-3:**

Regarding the recent property tax law changes enacted by the Texas Legislature in 2006, please provide all documentation related to SPS' calculation of its property tax obligations before such changes and after those changes.

**RESPONSE:**

Refer to SPS's response to Question Nos. AG-3-21 to Staff's Third Request for Information and TIEC4-27.

Preparer: Paul Simon
Sponsor: Timothy L. Willemsen

**QUESTION NO. 11-4:**

Please explain in detail SPS' treatment of property taxes in its rate filing package and the amount of property taxes in Texas SPS seeks to recover from ratepayers in Texas.

**RESPONSE:**

The test period level of property tax expense is included as an operating expense in taxes other than income. Refer to Attachment TLW-1 to the Direct Testimony of Timothy L. Willemsen, Volume RR-182 at Bates Stamp page 299.

Preparer: Timothy L. Willemsen
Sponsor: Timothy L. Willemsen

**QUESTION NO. 11-5:**

Please identify any disputes Xcel may have with the Internal Revenue Service (IRS) regarding the deductibility of Xcel's company-owned life insurance expenses.

**RESPONSE:**

Refer to Exhibit AXM11-5 for discussion from Xcel Energy's 10Q for the second quarter of 2006.

Preparer: Christopher A. Arend
Sponsor: Christopher A. Arend

**QUESTION NO. 11-6:**

For any dispute identified in response to the immediately preceding request for information, please explain the amount of company-owned life insurance expenses SPS seeks to recover through rates in Texas.

**RESPONSE:**

SPS is not seeking to recover any company-owned life insurance expenses through rates in Texas.

Preparer: Christopher A. Arend
Sponsor: Christopher A. Arend

**QUESTION NO. 11-7:**

Please explain in detail whether SPS seeks to recover from Texas ratepayers any penalties or estimated penalties that may be associated with an IRS ruling that would disallow the deductibility of Xcel's company-owned life insurance expenses, and if so, the amount of such penalties or estimated penalties SPS seeks to recover from Texas ratepayers through its pending rate request (i.e., Docket No. 32766).

**RESPONSE:**

SPS is not seeking to recover any penalties or estimated penalties associated with the corporate-owned life insurance dispute discussed above.

Preparer: Christopher A. Arend
Sponsor: Christopher A. Arend

**Certificate of Service**

I certify that on the 10th day of August 2006, a true and correct copy of the foregoing instrument was served on all parties of record by hand delivery, Federal Express, regular first class mail, certified mail, or facsimile transmission.

Amy M Shelhamer

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

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

**For the quarterly period ended June 30, 2006**

**or**

☐ **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**<br>(State or other jurisdiction of incorporation or organization) | **41-0448030**<br>(I.R.S. Employer Identification No.) |
| **414 Nicollet Mall, Minneapolis, Minnesota**<br>(Address of principal executive offices) | **55401**<br>(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. ☒ Yes ☐ 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 ☒ Accelerated Filer ☐ Non-Accelerated Filer ☐

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

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

| Class | Outstanding at July 28, 2006 |
|---|---|
| Common Stock, $2.50 par value | 405,967,399 shares |

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## PART I — FINANCIAL INFORMATION
### Item 1. Financial Statements

## XCEL ENERGY INC. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

| (Thousands of Dollars, Except Per Share Data) | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2006 | 2005 | 2006 | 2005 |
| **Operating revenues** | | | | |
| Electric utility | $ 1,786,571 | $ 1,720,431 | $ 3,632,443 | $ 3,255,378 |
| Natural gas utility | 270,990 | 326,347 | 1,289,130 | 1,161,402 |
| Nonregulated and other | 16,312 | 17,277 | 40,404 | 37,808 |
| Total operating revenues | 2,073,873 | 2,064,055 | 4,961,977 | 4,454,588 |
| **Operating expenses** | | | | |
| Electric fuel and purchased power — utility | 951,214 | 912,400 | 1,945,909 | 1,673,809 |
| Cost of natural gas sold and transported — utility | 168,822 | 232,039 | 1,019,247 | 900,824 |
| Cost of sales — nonregulated and other | 4,437 | 5,158 | 12,667 | 13,418 |
| Other operating and maintenance expenses — utility | 443,137 | 437,639 | 878,388 | 840,109 |
| Other operating and maintenance expenses — nonregulated | 6,614 | 9,274 | 12,178 | 16,418 |
| Depreciation and amortization | 203,665 | 193,976 | 406,325 | 385,670 |
| Taxes (other than income taxes) | 71,326 | 71,334 | 149,861 | 147,086 |
| Total operating expenses | 1,849,215 | 1,861,820 | 4,424,570 | 3,977,334 |
| **Operating income** | 224,658 | 202,235 | 537,407 | 477,254 |
| | | | | |
| Interest and other income — net of nonoperating expense (see Note 8) | 921 | 4,516 | 537 | 2,442 |
| Allowance for funds used during construction — equity | 4,668 | 5,450 | 8,452 | 10,633 |
| **Interest charges and financing costs** | | | | |
| Interest charges — includes other financing costs of $6,393, $6,418, $12,605 and $12,897, respectively | 119,283 | 114,375 | 238,657 | 228,017 |
| Allowance for funds used during construction — debt | (7,509) | (4,534) | (13,882) | (9,368) |
| Total interest charges and financing costs | 111,774 | 109,841 | 224,775 | 218,649 |
| Income from continuing operations before income taxes | 118,473 | 102,360 | 321,621 | 271,680 |
| Income taxes | 20,537 | 24,684 | 73,873 | 69,541 |
| Income from continuing operations | 97,936 | 77,676 | 247,748 | 202,139 |
| Income from discontinued operations — net of tax (see Note 2) | 339 | 5,730 | 1,825 | 2,745 |
| Net income | 98,275 | 83,406 | 249,573 | 204,884 |
| Dividend requirements on preferred stock | 1,060 | 1,060 | 2,120 | 2,120 |
| Earnings available to common shareholders | $ 97,215 | $ 82,346 | $ 247,453 | $ 202,764 |
| **Weighted average common shares outstanding (thousands)** | | | | |
| Basic | 405,434 | 402,214 | 404,783 | 401,668 |
| Diluted | 429,099 | 425,552 | 428,349 | 425,004 |
| **Earnings per share — basic** | | | | |
| Income from continuing operations | $ 0.24 | $ 0.19 | $ 0.61 | $ 0.50 |
| Discontinued operations | — | 0.01 | — | — |
| Earnings per share — basic | $ 0.24 | $ 0.20 | $ 0.61 | $ 0.50 |
| **Earnings per share — diluted** | | | | |
| Income from continuing operations | $ 0.24 | $ 0.19 | $ 0.59 | $ 0.49 |
| Discontinued operations | — | 0.01 | 0.01 | — |
| Earnings per share — diluted | $ 0.24 | $ 0.20 | $ 0.60 | $ 0.49 |

See Notes to Consolidated Financial Statements

**XCEL ENERGY INC. AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)**
**(Thousands of Dollars, Except Per Share Data)**

| | Six Months Ended June 30, | |
|---|---|---|
| | 2006 | 2005 |
| **Operating activities** | | |
| Net income | $ 249,573 | $ 204,884 |
| Remove income from discontinued operations | (1,825) | (2,745) |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 422,695 | 395,749 |
| Nuclear fuel amortization | 22,395 | 19,673 |
| Deferred income taxes | (41,460) | 29,983 |
| Amortization of investment tax credits | (4,902) | (5,809) |
| Allowance for equity funds used during construction | (8,452) | (10,633) |
| Undistributed equity in earnings of unconsolidated affiliates | (1,431) | (414) |
| Write down of assets | — | 3,258 |
| Unrealized (gain) loss on derivative instruments | (4,947) | 1,614 |
| Settlement of interest rate swap | 13,844 | — |
| Change in accounts receivable | 243,057 | (11,126) |
| Change in inventories | 139,640 | 107,760 |
| Change in other current assets | 427,733 | 45,726 |
| Change in accounts payable | (301,555) | (136,365) |
| Change in other current liabilities | (17,994) | (35,401) |
| Change in other noncurrent assets | (26,567) | 8,498 |
| Change in other noncurrent liabilities | 35,443 | 76,031 |
| Operating cash flows provided by discontinued operations | 75,530 | 106,536 |
| Net cash provided by operating activities | 1,220,777 | 797,219 |
| **Investing activities** | | |
| Utility capital/construction expenditures | (733,187) | (628,623) |
| Allowance for equity funds used during construction | 8,452 | 10,633 |
| Purchase of investments in external decommissioning fund | (11,570) | (70,360) |
| Proceeds from the sale of investments in external decommissioning fund | 14,083 | 30,745 |
| Nonregulated capital expenditures and asset acquisitions | (433) | (4,424) |
| Restricted cash | 2,132 | 1,621 |
| Other investments | 3,833 | 2,834 |
| Investing cash flows provided by discontinued operations | 42,377 | 83,357 |
| Net cash used in investing activities | (674,313) | (574,217) |
| **Financing activities** | | |
| Short-term borrowings — net | (608,120) | (17,300) |
| Proceeds from issuance of long-term debt | 882,877 | 1,283,388 |
| Repayment of long-term debt, including reacquisition premiums | (570,426) | (1,287,463) |
| Proceeds from issuance of common stock | 3,628 | 3,778 |
| Dividends paid | (175,939) | (167,845) |
| Financing cash flows used in discontinued operations | — | (200) |
| Net cash used in financing activities | (467,980) | (185,642) |
| Net increase in cash and cash equivalents | 78,484 | 37,360 |
| Net increase (decrease) in cash and cash equivalents - discontinued operations | 10,533 | (11,334) |
| Cash and cash equivalents at beginning of year | 72,196 | 23,361 |
| Cash and cash equivalents at end of quarter | $ 161,213 | $ 49,387 |
| Supplemental disclosure of cash flow information: | | |
| Cash paid for interest (net of amounts capitalized) | $ 212,719 | $ 206,488 |
| Cash paid for income taxes (net of refunds received) | $ (7,083) | $ 6,497 |
| Supplemental disclosure of non-cash investing transactions: | | |
| Property, plant and equipment additions | $ 47,345 | $ 27,743 |
| Supplemental disclosure of non-cash financing transactions: | | |
| Issuance of common stock for reinvested dividends and 401K's | $ 37,095 | $ 30,114 |

See Notes to Consolidated Financial Statements

**XCEL ENERGY INC. AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (UNAUDITED)**
**(Thousands of Dollars)**

| | June 30, 2006 | Dec. 31, 2005 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 161,213 | $ 72,196 |
| Accounts receivable — net of allowance for bad debts of $30,237 and $39,798, respectively | 768,607 | 1,011,569 |
| Accrued unbilled revenues | 398,680 | 614,016 |
| Materials and supplies inventories — at average cost | 169,383 | 159,560 |
| Fuel inventory — at average cost | 75,630 | 64,987 |
| Natural gas inventories — at average cost | 150,504 | 310,610 |
| Recoverable purchased natural gas and electric energy costs | 169,167 | 395,070 |
| Derivative instruments valuation | 169,296 | 213,138 |
| Prepayments and other | 169,254 | 99,904 |
| Current assets held for sale and related to discontinued operations | 251,826 | 200,811 |
| Total current assets | 2,483,560 | 3,141,861 |
| Property, plant and equipment, at cost: | | |
| Electric utility plant | 19,140,512 | 18,870,516 |
| Natural gas utility plant | 2,813,883 | 2,779,043 |
| Common utility and other | 1,496,780 | 1,518,266 |
| Construction work in progress | 1,100,868 | 783,490 |
| Total property, plant and equipment | 24,552,043 | 23,951,315 |
| Less accumulated depreciation | (9,588,028) | (9,357,414) |
| Nuclear fuel — net of accumulated amortization: $1,212,781 and $1,190,386, respectively | 122,246 | 102,409 |
| Net property, plant and equipment | 15,086,261 | 14,696,310 |
| Other assets: | | |
| Nuclear decommissioning fund and other investments | 1,169,974 | 1,145,659 |
| Regulatory assets | 939,610 | 963,403 |
| Derivative instruments valuation | 522,963 | 451,937 |
| Prepaid pension asset | 693,359 | 683,649 |
| Other | 150,039 | 164,212 |
| Noncurrent assets held for sale and related to discontinued operations | 213,080 | 401,285 |
| Total other assets | 3,689,025 | 3,810,145 |
| Total assets | $ 21,258,846 | $ 21,648,316 |
| | | |
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Current portion of long-term debt | $ 810,918 | $ 835,495 |
| Short-term debt | 138,000 | 746,120 |
| Accounts payable | 922,878 | 1,187,489 |
| Taxes accrued | 171,443 | 235,056 |
| Dividends payable | 91,298 | 87,788 |
| Derivative instruments valuation | 73,992 | 191,414 |
| Other | 325,840 | 345,807 |
| Current liabilities held for sale and related to discontinued operations | 35,166 | 43,657 |
| Total current liabilities | 2,569,535 | 3,672,826 |
| Deferred credits and other liabilities: | | |
| Deferred income taxes | 2,268,432 | 2,191,794 |
| Deferred investment tax credits | 126,498 | 131,400 |
| Regulatory liabilities | 1,747,128 | 1,710,820 |
| Derivative instruments valuation | 555,703 | 499,390 |
| Asset retirement obligations | 1,329,873 | 1,292,006 |
| Customer advances | 313,906 | 310,092 |
| Minimum pension liability | 88,280 | 88,280 |
| Benefit obligations and other | 354,351 | 343,201 |
| Noncurrent liabilities held for sale and related to discontinued operations | 4,852 | 6,936 |
| Total deferred credits and other liabilities | 6,789,023 | 6,573,919 |
| Minority interest in subsidiaries | 2,973 | 3,547 |
| Commitments and contingent liabilities (see Note 5) | | |
| Capitalization: | | |
| Long-term debt | 6,237,085 | 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: June 30, 2006 — 405,560,301; Dec. 31, 2005 — 403,387,159 | 5,555,250 | 5,395,255 |
| Total liabilities and equity | $ 21,258,846 | $ 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 June 30, 2005 and 2006 | | | | | | |
| **Balance at March 31, 2005** | 401,835 | $ 1,004,588 | $ 3,932,549 | $ 433,679 | $ (103,909) | $ 5,266,907 |
| Net income | | | | 83,406 | | 83,406 |
| Net derivative instrument fair value changes during the period (see Note 7) | | | | | (24,290) | (24,290) |
| Unrealized loss - marketable securities | | | | | (32) | (32) |
| Comprehensive income for the period | | | | | | 59,084 |
| Dividends declared: Cumulative preferred stock | | | | (1,060) | | (1,060) |
| Common stock | | | | (86,507) | | (86,507) |
| Issuances of common stock | 523 | 1,306 | 7,660 | | | 8,966 |
| **Balance at June 30, 2005** | 402,358 | $ 1,005,894 | $ 3,940,209 | $ 429,518 | $ (128,231) | $ 5,247,390 |
| | | | | | | |
| **Balance at March 31, 2006** | 405,087 | $ 1,012,719 | $ 3,994,628 | $ 625,283 | $ (114,039) | $ 5,518,591 |
| Net income | | | | 98,275 | | 98,275 |
| Net derivative instrument fair value changes during the period (see Note 7) | | | | | 10,320 | 10,320 |
| Unrealized gain - marketable securities | | | | | 6 | 6 |
| Comprehensive income for the period | | | | | | 108,601 |
| Dividends declared: Cumulative preferred stock | | | | (1,060) | | (1,060) |
| Common stock | | | | (90,235) | | (90,235) |
| Issuances of common stock | 473 | 1,182 | 7,459 | | | 8,641 |
| Share-based compensation (see Note 1) | | | 10,712 | | | 10,712 |
| **Balance at June 30, 2006** | 405,560 | $ 1,013,901 | $ 4,012,799 | $ 632,263 | $ (103,713) | $ 5,555,250 |

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 |
| Six months ended June 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 | | | | 204,884 | | 204,884 |
| Minimum pension liability | | | | | 220 | 220 |
| Net derivative instrument fair value changes during the period (see Note 7) | | | | | (22,512) | (22,512) |
| Unrealized loss - marketable securities | | | | | (5) | (5) |
| Comprehensive income for the period | | | | | | 182,587 |
| Dividends declared: | | | | | | |
| Cumulative preferred stock | | | | (2,120) | | (2,120) |
| Common stock | | | | (169,887) | | (169,887) |
| Issuances of common stock | 1,896 | 4,739 | 29,153 | | | 33,892 |
| Balance at June 30, 2005 | 402,358 | $ 1,005,894 | $ 3,940,209 | $ 429,518 | $ (128,231) | $ 5,247,390 |
| | | | | | | |
| Balance at Dec. 31, 2005 | 403,387 | $ 1,008,468 | $ 3,956,710 | $ 562,138 | $ (132,061) | $ 5,396,255 |
| Net income | | | | 249,573 | | 249,573 |
| Net derivative instrument fair value changes during the period (see Note 7) | | | | | 28,320 | 28,320 |
| Unrealized gain - marketable securities | | | | | 28 | 28 |
| Comprehensive income for the period | | | | | | 277,921 |
| Dividends declared: | | | | | | |
| Cumulative preferred stock | | | | (2,120) | | (2,120) |
| Common stock | | | | (177,328) | | (177,328) |
| Issuances of common stock | 2,173 | 5,433 | 35,290 | | | 40,723 |
| Share-based compensation (see Note 1) | | | 20,799 | | | 20,799 |
| **Balance at June 30, 2006** | 405,560 | $ 1,013,901 | $ 4,012,799 | $ 632,263 | $ (103,713) | $ 5,555,250 |

See Notes to Consolidated Financial Statements

In the opinion of management, the accompanying unaudited consolidated financial statements contain all adjustments necessary to present fairly the financial position of Xcel Energy Inc. and its subsidiaries (collectively, Xcel Energy) as of June 30, 2006, and Dec. 31, 2005; the results of its operations and changes in stockholders' equity for the three and six months ended June 30, 2006 and 2005; and its cash flows for the six months ended June 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.

**1. Significant Accounting Policies**

Except to the extent updated or described below, the significant accounting policies set forth in Note 1 to the consolidated financial statements in Xcel Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2005 appropriately represent, in all material respects, the current status of accounting policies, and are incorporated herein by reference.

***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 ended and year-to-date June 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 $13.9 million and $16.8 million was recorded in the second quarter of 2006 and 2005, respectively. Compensation expense related to share-based awards of approximately $21.0 million and $19.6 million was recorded in the first six months of 2006 and 2005, respectively. As of June 30, 2006, there was approximately $33.6 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 1.6 years. The amount of cash used to settle these awards was $11.3 million and $3.6 million for the first six months of 2006 and 2005, respectively.

There have been no material changes to outstanding stock options in the second 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. The Minnesota Public Utilities Commission (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 the 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.

*Reclassifications* — Certain items in the statements of income, balance sheets and the statements of cash flows have been reclassified from prior-period presentation to conform to the 2006 presentation. These reclassifications had no effect on net income or earnings per share. The reclassifications were primarily related to the presentation of Quixx Corp. (Quixx), a former subsidiary of Xcel Energy's non-regulated subsidiary, Utility Engineering (UE), that partners in cogeneration projects, as discontinued operations.

**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. Amounts previously reported for 2005 have been restated to conform to the 2006 discontinued operations presentation.

**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 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.

*Seren* — On Sept. 27, 2004, Xcel Energy's board of directors approved management's plan to pursue the sale of Seren Innovations, Inc., 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 $385 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 June 30, 2006** | | | |
| Operating revenue | $ — | $ 2,009 | $ 2,009 |
| Operating expenses and other income | (30) | 1,533 | 1,503 |
| Pretax income from operations of discontinued components | 30 | 476 | 506 |
| Income tax expense | 15 | 152 | 167 |
| Net income from discontinued operations | $ 15 | $ 324 | $ 339 |
| | | | |
| **Three months ended June 30, 2005** | | | |
| Operating revenue and equity in project income | $ — | $ 7,379 | $ 7,379 |
| Operating expenses and other income | — | (1,642) | (1,642) |
| Pretax income from operations of discontinued components | — | 9,021 | 9,021 |
| Income tax expense | — | 3,291 | 3,291 |
| Net income from operations of discontinued components | $ — | $ 5,730 | $ 5,730 |

| (Thousands of dollars) | Utility Segments | All Other | Total |
|---|---|---|---|
| **Six months ended June 30, 2006** | | | |
| Operating revenue | $ — | $ 4,838 | $ 4,838 |
| Operating expenses and other income | (18) | 6,165 | 6,147 |
| Pretax income (loss) from operations of discontinued components | 18 | (1,327) | (1,309) |
| Income tax benefit | (1,165) | (1,969) | (3,134) |
| Net income from discontinued operations | $ 1,183 | $ 642 | $ 1,825 |
| | | | |
| **Six months ended June 30, 2005** | | | |
| Operating revenue and equity in project income | $ 6,579 | $ 32,065 | $ 38,644 |
| Operating expenses and other income | 6,131 | 28,122 | 34,253 |
| Pretax income from operations of discontinued components | 448 | 3,943 | 4,391 |
| Income tax expense | 268 | 1,378 | 1,646 |
| Net income from operations of discontinued components | $ 180 | $ 2,565 | $ 2,745 |

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

| (Thousands of dollars) | June 30, 2006 | Dec. 31, 2005 |
|---|---|---|
| Cash | $ 23,191 | $ 12,658 |
| Trade receivables — net | 2,388 | 6,101 |
| Deferred income tax benefits | 200,674 | 157,812 |
| Other current assets | 25,573 | 24,240 |
| Current assets held for sale and related to discontinued operations | $ 251,826 | $ 200,811 |
| Property, plant and equipment — net | $ 2,988 | $ 29,845 |
| Deferred income tax benefits | 200,138 | 352,171 |
| Other noncurrent assets | 9,954 | 19,269 |
| Noncurrent assets held for sale and related to discontinued operations | $ 213,080 | $ 401,285 |
| Accounts payable — trade | $ 4,025 | $ 7,657 |
| Other current liabilities | 31,141 | 36,000 |
| Current liabilities held for sale and related to discontinued operations | $ 35,166 | $ 43,657 |
| Other noncurrent liabilities | $ 4,852 | $ 6,936 |
| Noncurrent liabilities held for sale and related to discontinued operations | $ 4,852 | $ 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 company-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 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. Xcel Energy has also been notified by the IRS that a statutory notice of deficiency for tax years 2000 through 2003 will be issued in third quarter 2006.

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 are scheduled to be presented on Aug. 8, 2006. If this motion is denied, the district court has ordered the parties to be ready for trial by Jan. 2, 2007.

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 retained 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, with the exception of two components which would be 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 requested written comments on the joint report, and action by the MPUC in response to the recommendations in this report is anticipated sometime 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.

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. To date, NSP-Wisconsin has deferred a total of approximately $6.2 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 granted a rehearing on the issue for purposes of further consideration on June 23, 2006, and is expected to issue a final order later in 2006. Xcel Energy has reserved $5.7 million in the event the FERC order is upheld on rehearing and appeal.

*Joint and Common Wholesale Energy Market*

On March 16, 2006, the FERC dismissed complaints filed by Wisconsin Public Service Corp. et al. (WPS) asking the FERC to order MISO and the PJM Interconnection, Inc. (PJM) to establish a joint and common wholesale energy market (JCM) for the two neighboring RTOs. Xcel Energy opposed the WPS complaints, arguing that MISO and PJM are completing projects shown to be cost beneficial to market participants, and a full JCM could substantially increase market operations costs with limited benefits in terms of energy savings. In dismissing the complaints, the FERC ruled the progress by MISO and PJM toward the JCM was satisfactory.

*Ancillary Service Markets*

MISO and its stakeholders are developing proposals to establish ancillary service markets within its 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. NSP-Minnesota signed a memoranda of understanding with MISO that permit NSP-Minnesota to participate in the development of agreements relating to regional generation reserve sharing. The MISO generation reserve sharing pool agreement was executed by numerous parties on July 31, 2006; however, the agreement provides an "opt out" in the event participation is lower than anticipated. Final participation will be determined by Aug. 4, 2006. NSP-Minnesota and NSP-Wisconsin will participate through a collective of participants in the existing Mid-Continent Area Power Pool generation reserve sharing agreement, which would be replaced by the MISO arrangement for contingency reserves.

*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 results in a $1.1 million stated rate increase for SPS effective June 2005, and SPS can 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 the SPP filing as inconsistent with the Feb. 6, 2006 settlement. SPP and SPS filed answers responding to the protests. Final FERC action is pending.

**Other Regulatory Matters — NSP-Minnesota**

*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 13, 2006, intervenors filed testimony regarding the Minnesota electric rate case. In its testimony, the Minnesota Department of Commerce proposed an increase in annual revenues of approximately $90 million, a return on equity of 10.64 percent and a proposed equity ratio of 51.37 percent, resulting in an overall return on rate base of 8.81 percent. The primary adjustments related to return on equity, nuclear decommissioning expense, ratemaking treatment of wholesale margins, adjustments to fuel expense and an increase in sales volumes. On the latter two issues the Department of Commerce indicated that the recommendations might change if NSP-Minnesota is able to supply additional information in its rebuttal testimony. The nuclear decommissioning recovery was reduced by $10.2 million and $21.1 million for the second quarter and first six months of 2006, respectively. The annual recovery decreased from $80.8 million to $42.5 million. The decrease was attributed to a change in cost estimate and recovery parameters.

The Office of Attorney General also filed testimony. It proposed two adjustments related to income taxes and wholesale margins that would result in a decrease in 2006 annual revenues of approximately $20 million. On March 30, 2006, NSP-Minnesota filed rebuttal testimony reducing the requested rate increase to $156 million. Evidentiary hearings concluded on April 27, 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 is pending approval by the MPUC and will be considered in the MPUC's determination of NSP-Minnesota's overall requested increase.

On July 6, 2006, the administrative law judge (ALJ) recommended an overall increase in revenues for the 2006 test year of approximately $135 million. For 2007, the ALJ recommended the increase be revised downward to $119 million to reflect the increased revenues expected due to the return of Flint Hills, an oil refinery, as a full-requirements customer. The MPUC is expected to hold oral arguments in August and issue its final order in September 2006.

*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. Excelsior Energy asked the MPUC to open a contested case proceeding to:

- Approve, disapprove, amend, or modify the terms and conditions of Excelsior Energy's proposed power purchase agreement;
- Determine that Excelsior Energy's coal-fueled IGCC plant is, or is likely to be, a least-cost resource, obligating NSP-Minnesota to use the plant's generation for at least 2 percent of the energy supplied to its retail customers; and
- Determine that at least 13 percent of the energy supplied to NSP-Minnesota retail customers should come from the IGCC plant by 2013.

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 as much contract price information as possible. 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. NSP-Minnesota anticipates opposing or seeking significant modification on Excelsior Energy's petition and power purchase agreement. NSP-Minnesota will 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.

**Other Regulatory Matters — NSP-Wisconsin**

***2006 Fuel Cost Recovery*** — NSP-Wisconsin's electric fuel costs for March 2006 were approximately $2.1 million, or 20 percent, lower than authorized in the 2006 Wisconsin electric rate case and outside the established fuel monitoring range under the Wisconsin fuel rules. Year-to-date fuel costs through March were approximately $1.9 million, or 6 percent, lower than authorized, resulting in an over recovery of $1.9 million. On May 4, 2006, the PSCW opened a proceeding to determine if a rate reduction (fuel credit factor) should be implemented, and made new rates reflecting the lower fuel costs effective May 4, 2006, subject to refund pending a full review of 2006 fuel costs.

In late May 2006, NSP-Wisconsin provided the PSCW with an updated forecast of fuel costs for the remainder of 2006 showing NSP-Wisconsin's fuel costs will be within the authorized range by year-end, and no rate reduction is warranted. The PSCW's investigation is ongoing.

Fuel costs for the Wisconsin retail jurisdiction through June 2006 were $0.8 million, or 1.0 percent lower than authorized in the 2006 rate case. However, NSP-Wisconsin's forecast continues to show that by year-end, fuel costs will be within the authorized range. NSP-Wisconsin anticipates the PSCW will complete their investigation and issue an order later this year.

***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 FCA. NSP-Wisconsin proposes to unbundle transmission service and revise the fuel costs adjustment clause (FCAC) to reflect current FERC regulatory policies, the advent of MISO operations and the Day 2 energy market.

**Other Regulatory Matters — PSCo**

***PSCo Electric Rate Case*** — On April 14, 2006, PSCo filed with the Colorado Public Utilities Commission (CPUC) to increase electricity rates by $210 million annually, beginning Jan. 1, 2007. The request is 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 has been implemented. A decision is expected by the end of 2006. The expected procedural schedule is listed below.

| | |
|---|---|
| • Intervenor Testimony | Aug. 18, 2006 |
| • Rebuttal Testimony | Sept. 29, 2006 |
| • Hearings | Oct. 23, 2006 through Nov. 9, 2006 |
| • Statement of Position | Nov. 20, 2006 |
| • Deliberations | Dec. 1, 2006 |
| • Initial Decision | Dec. 18, 2006 |

***PSCo 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.

***PSCo Renewable Portfolio Standards*** — In November 2004, an amendment to the Colorado statutes was passed by referendum requiring implementation of a renewable energy portfolio standard 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 renewable energy portfolio standard 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 renewable energy portfolio standard. PSCo is scheduled to file its first annual compliance plan under these rules by Aug. 31, 2006.

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 February 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.

***PSCo 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.

***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. In addition, the CPUC directed PSCo to respond to various other recommendations by the middle of August. 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.

**Other Regulatory Matters — SPS**

***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 has 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 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's regulations and rules of law, SPS has evaluated all sales made from Jan. 1, 1999, to Dec. 31, 2005. Notwithstanding that, SPS believes it should ultimately prevail in this proceeding. SPS has accrued approximately $7 million, of which $4 million was recorded in the second quarter of 2006, 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 mirror those that it made as an intervenor in the cooperatives' complaint case, and SPS believes that they have little merit. 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. A final settlement agreement will be filed for FERC approval. Hearings scheduled for December 2006 will be held in abeyance. Based on the fact that many of these issues are already being reviewed by the FERC in the complaint case filed by the cooperatives discussed above, the current status and expected outcome of this proceeding, SPS does not anticipate any additional liability.

***SPS 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 set the $2.5 million power rate increase to become 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; other wholesale customers have not settled, however. The revised base rates were placed in effect July 1, 2006, subject to refund.

***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, using a phased approach toward the development of a fully-functional locational marginal pricing energy market with appropriate FTRs, to be effective March 1, 2006. 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. SPP and market participants engaged in a series of technical conferences 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 July 25, 2006, SPP changed the implementation date to Nov. 1, 2006. SPS has not yet requested New Mexico Public Regulation Commission (NMPRC) or Public Utility Commission of Texas (PUCT) approval regarding accounting and ratemaking treatment of EIS costs.

***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 the first quarter of 2006, SPS revised its estimate of the allocation of fuel under-recoveries to its Texas jurisdiction for 2004 and 2005 and recorded an asset of approximately $7 million. In the second quarter of 2006, SPS finalized its fuel analysis based on a distribution system loss approach. Pursuant to this analysis, the total unrecovered fuel balance is $21.7 million. Because of uncertainty regarding ultimate recovery, a settlement reserve was recorded equal to the entire amount. SPS filed a fuel reconciliation application in May 2006. See discussion below.

***SPS Texas Retail Fuel Factor Change*** — On March 7, 2006, SPS filed an application to change its fuel factors effective May 1, 2006, to more accurately track fuel cost during the summer months. On April 17, 2006, the proposed factors were approved on an interim basis, and on May 25, 2006, the factors were granted final approval.

*SPS Texas Retail Fuel Surcharge Case* — On May 5, 2006, SPS requested authority to surcharge approximately $43.9 million of Texas retail fuel and purchased energy cost under-collection that accrued from October 2005 through March 2006. The case has been referred to the State Office Of Administrative Hearing (SOAH) for a contested hearing. Intervenors have requested that this case be consolidated with SPS' pending fuel reconciliation case discussed below, since findings in the fuel reconciliation case could reduce the amount of the under-collection. At a pre-hearing conference on June 26, 2006, the ALJ denied the motion to consolidate and set the case for hearing on its merits on Aug. 14, 2006.

*SPS 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. Final rates are expected to be effective in the first quarter of 2007. No interim rate increase has been implemented. Following is the expected procedural schedule.

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| • Intervenor Testimony | Oct. 24 & 31, 2006 |
| • PUCT Staff Testimony | Nov. 7, 2006 |
| • Hearings | Nov. 28 - Dec. 21, 2006 |
| • Proposal for Decision | To be determined |
| • Agreed Jurisdictional Deadline | March 2, 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 $25.3 million for its potential liability for remediating the Ashland site. Since NSP-Wisconsin cannot currently estimate the cost of remediating the Ashland site, the recorded liability is based upon the minimum of the estimated range of remediation costs, using information available to date and reasonably effective remedial methods. Of the total accrued, NSP-Wisconsin recorded an additional $5.7 million in the second quarter 2006 to reflect estimated legal defense and additional work plan costs.

*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 believes the cost of any required capital investment will be recoverable from customers. Emissions controls will 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. By Sept. 10, 2006, each BART-eligible source in Minnesota must perform and submit an analysis of the need for additional emission controls for sulfur dioxide ($SO_2$) and/or nitrous oxide ($NO_x$). The Sherburne County generating plant is the only NSP-Minnesota facility that is required to perform such an analysis and may eventually be required to install additional emission controls.

*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.

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 Minnesota Pollution Control Agency (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 September 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.

***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.

***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. Xcel Energy continues to evaluate the strategy for complying with CAMR. Compliance may be achieved by either adding mercury controls or purchasing allowances or a combination of both. The capital cost is estimated at $29.3 million for the mercury control equipment. 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. 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. 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*** — The Governor of Minnesota signed mercury reduction legislation in 2006. This legislation requires the installation of mercury monitoring equipment by July 1, 2007; submittal of mercury emission reduction plans for dry scrubbed units by Dec. 31, 2007 and for wet scrubbed units by Dec. 31, 2009; and installation of mercury emission control equipment at NSP-Minnesota's Allen S. King and Sherburne County (Sherco) generating facilities in Minnesota. Mercury emission control equipment must be installed on unit 3 of Sherco and at Allen S. King by Dec. 31, 2009 and Dec. 31, 2010. Sherco units 1 and 2 modifications are required by Dec. 31, 2014. The cost of controls will be determined as part of the engineering analysis portion of the mercury reduction plans and is not currently estimable. The legislation includes full and timely cost recovery provisions for both the costs of complying with this statute and any federal and state environmental regulations effective after Dec. 31, 2004.

**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 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 natural gas sellers to inflate prices through alleged false reporting of natural 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 and filed a second motion to dismiss the lawsuit. In response to this motion, this matter has been transferred to U.S. District Court Judge Pro. Judge Pro granted the motions to dismiss and plaintiffs have appealed. The 9th Circuit Court of Appeals has stayed this appeal until November 20, 2006, pending the court's decision in the prior appeal filed in Abelman Art Glass vs. e prime et al.

***J.P. Morgan Trust Company vs. e prime and Xcel Energy Inc. et al.*** — On Oct. 17, 2005, J.P. Morgan, 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 increase 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 this case to state court has been filed by plaintiffs and on March 2, 2006, Judge Pro granted plaintiffs' motion for remand, but vacated this order on March 8, 2006, and will give the matter further consideration. This case is in the early stages, there has been no discovery, and e prime and Xcel Energy intend to vigorously defend themselves against these claims.

***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 the 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 such 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 such negotiations are ongoing. Trial remains set for August 2006, but is likely to be continued due to ongoing negotiations. If settlement discussions are not productive, additional summary judgment motions are likely prior to trial.

***Hoffman vs. Northern States Power Company*** — On March 15, 2006, a purported class action complaint was filed in Minnesota state district court, 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 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, scheduled to be heard on August 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 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 filed notice of intent to appeal to the U.S. Court of Appeals for the Eighth Circuit.

*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. It is uncertain whether plaintiffs will appeal.

*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.

*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 seeks, through this action, foreclosure of the lien and sale of the property. NewMech additionally seeks the claimed damages as a result of an alleged breach of contract by NSP-Minnesota. NSP-Minnesota, SMMPA and Benson have filed answers denying NewMech's allegations. Additionally, NSP-Minnesota and SMMPA have 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.

*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 is 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.

*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 ($CO_2$) emissions. The other utilities include American Electric Power Co., Southern Co., Cinergy Corp. and Tennessee Valley Authority. $CO_2$ is emitted whenever fossil fuel is combusted, such as in automobiles, industrial operations and coal- or gas-fired power plants. The lawsuits allege that $CO_2$ emitted by each company is a public nuisance as defined under state and federal common law because it has contributed to global warming. The lawsuits do not demand monetary damages. Instead, the lawsuits ask the court to order each utility to cap and reduce its $CO_2$ emissions. In October 2004, Xcel Energy and 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. Oral arguments were presented on June 7, 2006 and a decision on the appeal is pending.

**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 June 30, 2006, Xcel Energy and its subsidiaries had $138.0 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 June 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 June 30, 2006, was approximately $133.2 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 commodity price, interest rate, short-term wholesale and commodity trading activities, including forward contracts, futures, swaps and options. 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," 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 any regulatory mechanism in place. 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.

At June 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 June 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 June 30, 2006, Xcel Energy had net gains of approximately $2.7 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 no hedge ineffectiveness in the second 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 June 30, 2006 | Three months ended June 30, 2005 |
|---|---|---|
| Accumulated other comprehensive income related to cash flow hedges at March 31 | $ 9.2 | $ 1.9 |
| After-tax net unrealized gains (losses) related to derivatives accounted for as hedges | 12.1 | (22.0) |
| After-tax net realized gains on derivative transactions reclassified into earnings | (1.8) | (2.3) |
| Accumulated other comprehensive income (loss) related to cash flow hedges at June 30 | $ 19.5 | $ (22.4) |

| (Millions of Dollars) | Six months ended June 30, 2006 | Six months ended June 30, 2005 |
|---|---|---|
| Accumulated other comprehensive (loss) income related to cash flow hedges at Jan. 1 | $ (8.8) | $ 0.1 |
| After-tax net unrealized gains (losses) related to derivatives accounted for as hedges | 28.8 | (17.9) |
| After-tax net realized gains on derivative transactions reclassified into earnings | (0.5) | (4.6) |
| Accumulated other comprehensive income (loss) related to cash flow hedges at June 30 | $ 19.5 | $ (22.4) |

**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, as amended. 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 (Expense) - Net**

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

| (Thousands of Dollars) | Three months ended June 30, 2006 | Three months ended June 30, 2005 |
|---|---|---|
| Interest income | 5,720 | 4,261 |
| Equity income in unconsolidated affiliates | 1,092 | 814 |
| Other nonoperating income | 2,828 | 5,443 |
| Loss on the sale of investments | (909) | — |
| Minority interest income | 253 | 408 |
| Interest expense on corporate-owned life insurance and other employee-related insurance policies | (7,977) | (4,841) |
| Other nonoperating expense | (86) | (1,569) |
| Total interest and other income - net | $ 921 | $ 4,516 |

| (Thousands of Dollars) | Six months ended June 30, 2006 | Six months ended June 30, 2005 |
|---|---|---|
| Interest income | 9,799 | 6,640 |
| Equity income in unconsolidated affiliates | 2,278 | 1,313 |
| Other nonoperating income | 4,319 | 6,752 |
| Loss on the sale of investments | (1,818) | — |
| Minority interest income | 303 | 519 |
| Interest expense on corporate-owned life insurance and other employee-related insurance policies | (13,558) | (9,536) |
| Other nonoperating expense | (786) | (3,246) |
| Total interest and other income - net | $ 537 | $ 2,442 |

**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 six months ending June 30, 2006 and 2005:

| (Amounts in thousands, except per share amounts) | Three months ended June 30, 2006 Income | Shares | Per-share Amount | Three months ended June 30, 2005 Income | Shares | Per-share Amount |
|---|---|---|---|---|---|---|
| Income from continuing operations | $ 97,936 | | | $ 77,676 | | |
| Less: Dividend requirements on preferred stock | (1,060) | | | (1,060) | | |
| **Basic earnings per share:** | | | | | | |
| Income from continuing operations | 96,876 | 405,434 | $ 0.24 | 76,616 | 402,214 | $ 0.19 |
| Effect of dilutive securities: | | | | | | |
| $230 million convertible debt | 3,044 | 18,654 | | 2,896 | 18,654 | |
| $57.5 million convertible debt | 779 | 4,663 | | 724 | 4,663 | |
| 401(k) match | — | 330 | | — | — | |
| Stock options | — | 18 | | — | 21 | |
| **Diluted earnings per share:** | | | | | | |
| Income from continuing operations and assumed conversions | $ 100,699 | 429,099 | $ 0.24 | $ 80,236 | 425,552 | $ 0.19 |

| (Amounts in thousands, except per share amounts) | Six months ended June 30, 2006 Income | Shares | Per-share Amount | Six months ended June 30, 2005 Income | Shares | Per-share Amount |
|---|---|---|---|---|---|---|
| Income from continuing operations | $247,748 | | | $202,139 | | |
| Less: Dividend requirements on preferred stock | (2,120) | | | (2,120) | | |
| **Basic earnings per share:** | | | | | | |
| Income from continuing operations | 245,628 | 404,783 | $ 0.61 | 200,019 | 401,668 | $ 0.50 |
| Effect of dilutive securities: | | | | | | |
| $230 million convertible debt | 6,002 | 18,654 | | 5,707 | 18,654 | |
| $57.5 million convertible debt | 1,501 | 4,663 | | 1,427 | 4,663 | |
| 401(k) match | — | 231 | | — | — | |
| Stock options | — | 18 | | — | 19 | |
| **Diluted earnings per share:** | | | | | | |
| Income from continuing operations and assumed conversions | $253,131 | 428,349 | $ 0.59 | $207,153 | 425,004 | $ 0.49 |

**10. Benefit Plans and Other Postretirement Benefits**

Components of Net Periodic Benefit Cost

| (Thousands of dollars) | Three months ended June 30, Pension Benefits 2006 | Pension Benefits 2005 | Postretirement Health Care Benefits 2006 | Postretirement Health Care Benefits 2005 |
|---|---|---|---|---|
| Service cost | $ 14,380 | $ 12,980 | $ 1,479 | $ 1,599 |
| Interest cost | 38,197 | 39,496 | 13,287 | 13,663 |
| Expected return on plan assets | (67,551) | (69,484) | (7,110) | (6,267) |
| Amortization of transition obligation | — | — | 3,577 | 3,644 |
| Amortization of prior service cost (credit) | 7,421 | 7,496 | (545) | (544) |
| Amortization of net (gain) loss | 4,165 | (39) | 5,875 | 6,460 |
| Net periodic benefit cost (credit) | (3,388) | (9,551) | 16,563 | 18,555 |
| Credits not recognized due to the effects of regulation | 3,893 | 6,500 | — | — |
| Additional cost recognized due to the effects of regulation | — | — | 973 | 973 |
| Net benefit cost (credit) recognized for financial reporting | $ 505 | $ (3,051) | $ 17,536 | $ 19,528 |

| (Thousands of dollars) | Six months ended June 30, 2006 | 2005 | 2006 | 2005 |
|---|---|---|---|---|
| | Pension Benefits | | Postretirement Health Care Benefits | |
| Service cost | $ 30,814 | $ 30,230 | $ 3,316 | $ 3,342 |
| Interest cost | 77,706 | 80,492 | 26,470 | 27,530 |
| Expected return on plan assets | (134,032) | (139,758) | (13,378) | (12,850) |
| Amortization of transition obligation | — | — | 7,222 | 7,289 |
| Amortization of prior service cost (credit) | 14,848 | 15,018 | (1,090) | (1,089) |
| Amortization of net loss | 8,676 | 3,410 | 12,398 | 13,123 |
| Net periodic benefit cost (credit) | (1,988) | (10,608) | 34,938 | 37,345 |
| Credits not recognized due to the effects of regulation | 6,318 | 9,684 | — | — |
| Additional cost recognized due to the effects of regulation | — | — | 1,946 | 1,946 |
| Net benefit cost (credit) recognized for financial reporting | $ 4,330 | $ (924) | $ 36,884 | $ 39,291 |

**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 June 30, 2006** | | | | | |
| Operating revenues from external customers | $ 1,786,571 | $ 270,990 | $ 16,312 | $ — | $ 2,073,873 |
| Intersegment revenues | 225 | 1,228 | | (1,453) | |
| Total revenues | $ 1,786,796 | $ 272,218 | $ 16,312 | $ (1,453) | $ 2,073,873 |
| Income (loss) from continuing operations | $ 93,783 | $ 2,955 | $ 20,783 | $ (19,585) | $ 97,936 |
| **Three months ended June 30, 2005** | | | | | |
| Operating revenues from external customers | $ 1,720,431 | $ 326,347 | $ 17,277 | $ — | $ 2,064,055 |
| Intersegment revenues | (48) | 3,973 | — | (3,925) | — |
| Total revenues | $ 1,720,383 | $ 330,320 | $ 17,277 | $ (3,925) | $ 2,064,055 |
| Income (loss) from continuing operations | $ 88,751 | $ 931 | $ 7,718 | $ (19,724) | $ 77,676 |

| (Thousands of Dollars) | Regulated Electric Utility | Regulated Natural Gas Utility | All Other | Reconciling Eliminations | Consolidated Total |
|---|---|---|---|---|---|
| **Six months ended June 30, 2006** | | | | | |
| Operating revenues from external customers | $ 3,632,443 | $ 1,289,130 | $ 40,404 | $ — | $ 4,961,977 |
| Intersegment revenues | 387 | 3,767 | | (4,154) | |
| Total revenues | $ 3,632,830 | $ 1,292,897 | $ 40,404 | $ (4,154) | $ 4,961,977 |
| Income (loss) from continuing operations | $ 203,734 | $ 48,174 | $ 28,717 | $ (32,877) | $ 247,748 |
| **Six months ended June 30, 2005** | | | | | |
| Operating revenues from external customers | $ 3,255,378 | $ 1,161,402 | $ 37,808 | $ — | $ 4,454,588 |
| Intersegment revenues | 310 | 5,098 | — | (5,408) | — |
| Total revenues | $ 3,255,688 | $ 1,166,500 | $ 37,808 | $ (5,408) | $ 4,454,588 |
| Income (loss) from continuing operations | $ 164,140 | $ 52,196 | $ 16,569 | $ (30,766) | $ 202,139 |

**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. Actual results 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 June 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.

Prior-year financial statements have been reclassified to conform to the current year presentation and classification of certain operations as discontinued. See Note 2 to the consolidated financial statements for a further discussion of discontinued operations.

| Contribution to Earnings (Millions of dollars) | Three months ended June 30, 2006 | Three months ended June 30, 2005 | Six months ended June 30, 2006 | Six months ended June 30, 2005 |
|---|---|---|---|---|
| GAAP income (loss) by segment | | | | |
| Regulated electric utility segment income — continuing operations | $ 93.7 | $ 88.7 | $ 203.7 | $ 164.1 |
| Regulated natural gas utility segment income — continuing operations | 3.0 | 0.9 | 48.2 | 52.2 |
| Other utility results (a) | 5.2 | 4.8 | 12.1 | 12.9 |
| Utility segment income — continuing operations | 101.9 | 94.4 | 264.0 | 229.2 |
| | | | | |
| Holding company and other costs (a) | (3.9) | (16.7) | (16.2) | (27.0) |
| Income — continuing operations | 98.0 | 77.7 | 247.8 | 202.2 |
| | | | | |
| Regulated utility income — discontinued operations | — | — | 1.2 | 0.2 |
| Other nonregulated income — discontinued operations | 0.3 | 5.7 | 0.6 | 2.5 |
| Income — discontinued operations | 0.3 | 5.7 | 1.8 | 2.7 |
| Total GAAP income | $ 98.3 | $ 83.4 | $ 249.6 | $ 204.9 |

| | Three months ended June 30, 2006 | Three months ended June 30, 2005 | Six months ended June 30, 2006 | Six months ended June 30, 2005 |
|---|---|---|---|---|
| GAAP earnings per share contribution by segment | | | | |
| Regulated electric utility segment — continuing operations | $ 0.22 | $ 0.21 | $ 0.48 | $ 0.39 |
| Regulated natural gas utility segment — continuing operations | | | 0.11 | 0.12 |
| Other utility results (a) | 0.02 | 0.01 | 0.03 | 0.03 |
| Utility segment earnings per share — continuing operations | 0.24 | 0.22 | 0.62 | 0.54 |
| | | | | |
| Holding company and other costs (a) | — | (0.03) | (0.03) | (0.05) |
| Earnings per share — continuing operations | 0.24 | 0.19 | 0.59 | 0.49 |
| | | | | |
| Regulated utility earnings — discontinued operations | — | — | 0.01 | — |
| Other nonregulated earnings — discontinued operations | | 0.01 | | |
| Earnings per share — discontinued operations | — | 0.01 | 0.01 | — |
| Total GAAP earnings per share — diluted | $ 0.24 | $ 0.20 | $ 0.60 | $ 0.49 |

(a) 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 six months ended June 30, 2006 earnings per share compared with the same period in 2005, which are discussed in more detail later.

| Increase (decrease) | Three months ended June 30, 2006 vs. 2005 | Six months ended June 30, 2006 vs. 2005 |
|---|---|---|
| 2005 Earnings per share — diluted | $ 0.20 | $ 0.49 |
| *Components of change — 2006 vs. 2005* | | |
| Higher base electric utility margins | 0.10 | 0.20 |
| Lower short-term wholesale and commodity trading margins | (0.06) | (0.05) |
| Higher depreciation and amortization expense | (0.01) | (0.03) |
| Higher operating and maintenance expense | (0.01) | (0.06) |
| Lower effective tax rate and other | 0.03 | 0.04 |
| Net change in earnings per share — continuing operations | 0.05 | 0.10 |
| *Changes in Earnings Per Share — Discontinued Operations* | (0.01) | 0.01 |
| 2006 Earnings per share — diluted | $ 0.24 | $ 0.60 |

**Utility Segment Results**

Earnings for the second quarter of 2006 increased primarily due to stronger base electric and natural gas utility margins, partially offset by lower short-term wholesale margins. The stronger utility margins include the positive impact of a natural gas rate increase in Colorado, an electric and natural gas rate increase in Wisconsin, an interim electric rate increase in Minnesota and revenue associated with the 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):

| | Earnings per Share Increase (Decrease) | | |
|---|---|---|---|
| | 2006 vs. Normal | 2005 vs. Normal | 2006 vs. 2005 |
| Three months ended June 30 | $ 0.02 | $ (0.01) | $ 0.01 |
| Six months ended June 30 | $ (0.01) | $ (0.00) | $ (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.

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 — Second Quarter 2006 vs. Second 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 retail 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 realized 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 June 30, 2006 | | | | |
| Electric utility revenue (excluding commodity trading) | $ 1,761 | $ 34 | $ — | $ 1,795 |
| Electric fuel and purchased power | (913) | (38) | | (951) |
| Commodity trading revenue | — | — | 119 | 119 |
| Commodity trading costs | | | (127) | (127) |
| Gross margin before operating expenses | $ 848 | $ (4) | $ (8) | $ 836 |
| Margin as a percentage of revenue | 48.2% | (11.8)% | (6.7)% | 43.7% |
| | | | | |
| Three months ended June 30, 2005 | | | | |
| Electric utility revenue (excluding commodity trading) | $ 1,655 | $ 58 | $ — | $ 1,713 |
| Electric fuel and purchased power | (878) | (34) | | (912) |
| Commodity trading revenue | — | — | 115 | 115 |
| Commodity trading costs | | | (108) | (108) |
| Gross margin before operating expenses | $ 777 | $ 24 | $ 7 | $ 808 |
| Margin as a percentage of revenue | 46.9% | 41.4% | 6.1% | 44.2% |

Short-term wholesale and commodity trading margins decreased approximately $43 million for the second quarter of 2006, compared with the same period in 2005. As expected, short-term margins declined due to retail sales growth, which reduced surplus generation available for sale in the wholesale market, and decreased opportunities to sell due to the MISO centralized dispatch market. In addition, during the second quarter of 2006 a $6 million charge was recorded to commodity trading margins for the estimated impact of a FERC order regarding the allocation of MISO charges to certain trading activities.

In addition, NSP-Minnesota entered into a wholesale electric sales margin settlement agreement in the second quarter of 2006 as part of the Minnesota rate case proceeding. The agreement is pending MPUC approval. The settlement agreement provides for a sharing of certain short-term wholesale and commodity trading margins with retail electric customers beginning Jan. 1, 2006. The financial impact of this agreement is reflected in the financial statements as of and for the period ended June 30, 2006. See Note 4 for more information.

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

***Base Electric Utility Revenue***

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| Fuel and purchased power cost recovery | $ 44 |
| NSP-Minnesota interim base rate changes, subject to refund | 40 |
| Firm wholesale | 10 |
| MERP rider | 9 |
| Conservation and non-fuel rider revenue | 9 |
| Estimated impact of weather | 6 |
| NSP-Wisconsin rate case | 5 |
| Quality of Service obligations | 4 |
| Sales growth (excluding weather impact) | 1 |
| SPS fuel adjustments | (7) |
| Purchased capacity costs | (6) |
| Transmission revenue | (4) |
| Other | (5) |
| Total base electric utility revenue increase | $ 106 |

***Base Electric Utility Margin***

Base electric utility margins, which are primarily derived from retail customer sales, increased approximately $71 million for the second quarter of 2006, compared with the second quarter of 2005. The increase was primarily due to an interim rate increase in Minnesota, subject to refund, the impact of weather and revenue associated with the MERP. For more information see the following table:

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| NSP-Minnesota interim base rate changes, subject to refund | $ 40 |
| MERP rider | 9 |
| Conservation and non-fuel rider revenue | 9 |
| Estimated impact of weather | 8 |
| Firm wholesale | 6 |
| NSP-Wisconsin rate changes | 5 |
| Purchased capacity costs | (5) |
| Sales growth (excluding weather impact) | 4 |
| Quality of service obligations | 4 |
| Other | (9) |
| Total base electric utility margin increase | $ 71 |

**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.

| (Millions of dollars) | Three months ended June 30, 2006 | 2005 |
|---|---|---|
| Natural gas utility revenue | $ 271 | $ 326 |
| Cost of natural gas sold and transported | (169) | (232) |
| Natural gas utility margin | $ 102 | $ 94 |

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

*Natural Gas Revenue*

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| Purchased gas adjustment clause recovery | (52) |
| Estimated impact of weather | (11) |
| Base rate changes — Colorado, Wisconsin | 5 |
| Sales growth, excluding weather impacts | 3 |
| Off-system sales | (1) |
| Other | 1 |
| Total natural gas revenue decrease | $ (55) |

Natural gas revenue decreased mainly due to lower natural gas costs in 2006.

*Natural Gas Margin*

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| Base rate changes — Colorado, Wisconsin | 8 |
| Estimated impact of weather | (5) |
| Sales growth, excluding weather impacts | 4 |
| Transportation | 2 |
| Other | (1) |
| Total natural gas margin increase | $ 8 |

**Nonregulated Operating Margins**

The following table details the change in nonregulated revenue and margin, included in continuing operations.

| (Millions of Dollars) | Three months ended June 30, 2006 | 2005 |
|---|---|---|
| Nonregulated and other revenue | $ 16 | $ 17 |
| Nonregulated cost of goods sold | (4) | (5) |
| Nonregulated margin | $ 12 | $ 12 |

**Non-Fuel Operating Expense and Other Costs**

***Other Operating and Maintenance Expenses — Utility*** — Other operating and maintenance expenses for the second quarter of 2006 increased $5 million, or 1.3 percent, compared with the same period in 2005. Employee benefit costs decreased approximately $7 million for the three months ended June 30, 2006 compared with the same period in 2005, primarily due to the year-to-date true ups to new actuarial estimates for pension, retiree medical and disability costs. For more information see the following table.

| (Millions of Dollars) | Three months ended June 30, 2006 vs. 2005 |
|---|---|
| Lower employee benefit costs | $ (7) |
| Lower bad debt expense | (3) |
| Lower information technology costs | (1) |
| Higher nuclear plant operating costs | 5 |
| Higher combustion/hydro plant costs | 4 |
| Higher vegetation management and damage prevention costs | 3 |
| Higher conservation incentive program costs | 2 |
| Other | 2 |
| Total operating and maintenance expense increase | $ 5 |

***Depreciation and Amortization*** — Depreciation and amortization expense increased by approximately $10 million, or 5.0 percent, for the second quarter of 2006, compared with the same period in 2005. The increase is due to normal plant additions and a recently approved change in decommissioning accruals resulting in an additional depreciation expense of $4.5 million for the current quarter.

***Income taxes*** — Income taxes for continuing operations decreased by $4.1 million for the second quarter of 2006, compared with 2005. The effective tax rate for continuing operations was 17.3 percent for the second quarter of 2006, compared with 24.1 percent for the same period in 2005. The reduction in income taxes and in the effective tax rate was primarily due to the recognition of a tax benefit of $16.6 million for the second quarter of 2006 relating to capital loss carry forwards that are now considered realizable. Previously, such tax benefits did not meet the recognition threshold under tax accounting requirements, due to the absence of likely capital gains which provided the opportunity to make use of the capital loss carry forwards.

**Income Statement Analysis — First Six Months of 2006 vs. First Six 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 |
|---|---|---|---|---|
| Six months ended June 30, 2006 | | | | |
| Electric utility revenue (excluding commodity trading) | $ 3,555 | $ 72 | $ — | $ 3,627 |
| Electric fuel and purchased power | (1,882) | (64) | | (1,946) |
| Commodity trading revenue | — | — | 335 | 335 |
| Commodity trading costs | | | (329) | (329) |
| Gross margin before operating expenses | $ 1,673 | $ 8 | $ 6 | $ 1,687 |
| Margin as a percentage of revenue | 47.1% | 11.1% | 1.8% | 42.6% |
| | | | | |
| Six months ended June 30, 2005 | | | | |
| Electric utility revenue (excluding commodity trading) | $ 3,157 | $ 91 | $ — | $ 3,248 |
| Electric fuel and purchased power | (1,622) | (52) | | (1,674) |
| Commodity trading revenue | — | — | 232 | 232 |
| Commodity trading costs | | | (225) | (225) |
| Gross margin before operating expenses | $ 1,535 | $ 39 | $ 7 | $ 1,581 |
| Margin as a percentage of revenue | 48.6% | 42.9% | 3.0% | 45.4% |

Short-term wholesale and commodity trading margins decreased approximately $32 million for the six months ended June 30, 2006, compared with the same period in 2005. As expected, short-term margins declined due to retail sales growth, which reduced surplus generation available for sale in the wholesale market, and decreased opportunities to sell due to the MISO centralized dispatch market. In addition, during the second quarter of 2006 a $6 million charge was recorded to commodity trading margins for the estimated impact of a FERC order regarding the allocation of MISO charges to certain trading activities.

In addition, NSP-Minnesota entered into a wholesale electric sales margin settlement agreement in the second quarter of 2006 as part of the Minnesota rate case proceeding. The agreement is pending MPUC approval. The settlement agreement provides for a sharing of certain short-term wholesale margins with retail electric customers beginning Jan. 1, 2006. The financial impact of this agreement is reflected in the financial statements as of and for the period ended June 30, 2006.

The following summarizes the components of the changes in base electric utility revenue and base electric utility margin for the six months ended June 30:

***Base Electric Utility Revenue***

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| Fuel and purchased power cost recovery | $ 234 |
| NSP-Minnesota interim base rate changes, subject to refund | 65 |
| Firm wholesale | 33 |
| Sales growth (excluding weather impact) | 27 |
| MERP rider | 18 |
| Conservation and non-fuel rider revenue | 13 |
| NSP-Wisconsin rate changes | 7 |
| Quality of service obligations | 6 |
| Estimated impact of weather | 2 |
| Purchased capacity costs | (11) |
| Transmission revenue | (3) |
| Other | 7 |
| Total base electric utility revenue increase | $ 398 |

***Base Electric Utility Margin***

Base electric utility margins, which are primarily derived from retail customer sales, increased approximately $138 million for the first six months of 2006, compared with the same period in 2005. The increase was primarily due to an interim rate increase in Minnesota, subject to refund, weather-adjusted retail sales growth and revenue associated with the MERP. For more information see the following table:

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| NSP-Minnesota interim base rate changes, subject to refund | $ 65 |
| Sales growth (excluding weather impact) | 24 |
| MERP rider | 18 |
| Firm wholesale | 14 |
| Conservation and non-fuel rider revenue | 13 |
| NSP-Wisconsin rate changes | 7 |
| Quality of service obligation | 6 |
| Purchased capacity costs | (6) |
| Estimated impact of weather | 4 |
| Other | (7) |
| Total base electric utility margin increase | $ 138 |

**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.

| | Six Months Ended June 30, | |
|---|---|---|
| (Millions of Dollars) | 2006 | 2005 |
| Natural gas utility revenue | $ 1,289 | $ 1,161 |
| Cost of natural gas sold and transported | (1,019) | (901) |
| Natural gas utility margin | $ 270 | $ 260 |

The following summarizes the components of the changes in natural gas revenue and margin for the six months ended June 30:

***Natural Gas Revenue***

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| Purchased gas adjustment clause recovery | $ 151 |
| Base rate changes — Colorado, Wisconsin | 12 |
| Estimated impact of weather | (29) |
| Off system sales | (5) |
| Sales decline (excluding weather impact) | (2) |
| Other | 1 |
| Total natural gas revenue increase | $ 128 |

Natural gas revenue increased mainly due to higher natural gas costs in 2006, which were passed through to customers, partially offset by decreased sales volumes reflecting the impact of weather.

***Natural Gas Margin***

| (Millions of dollars) | 2006 vs. 2005 |
|---|---|
| Base rate changes — Colorado, Wisconsin | $ 12 |
| Transportation | 4 |
| Estimated impact of weather | (8) |
| Sales decline (excluding weather impact) | (1) |
| Other | 3 |
| Total natural gas margin increase | $ 10 |

**Nonregulated Operating Margins**

The following table details the change in nonregulated revenue and margin, included in continuing operations.

| (Millions of Dollars) | Six Months Ended June 30, 2006 | Six Months Ended June 30, 2005 |
|---|---|---|
| Nonregulated and other revenue | $ 40 | $ 38 |
| Nonregulated cost of goods sold | (13) | (13) |
| Nonregulated margin | $ 27 | $ 25 |

**Non-Fuel Operating Expense and Other Costs**

***Other Operating and Maintenance Expenses — Utility*** — Other operating and maintenance expenses for the first six months of 2006 increased $38 million, or 4.6 percent, compared with the same period in 2005. The increase is primarily due to higher plant operating expenses which were partially offset by lower nuclear plant outage costs. Such outage costs were lower due to two nuclear plant refueling, inspection and upgrade outages in 2005 compared with one refueling outage in the same period of 2006. For more information, see the following table:

| (Millions of Dollars) | Six months ended June 30, 2006 vs. 2005 |
|---|---|
| Lower nuclear plant outage costs | $ (18) |
| Higher nuclear plant operating costs | 9 |
| Higher combustion/hydro plant costs | 11 |
| Higher vegetation management and damage prevention costs | 9 |
| Higher bad debt expense | 6 |
| Higher information technology costs | 4 |
| Higher conservation incentive program costs | 4 |
| Higher insurance costs | 2 |
| Other | 11 |
| Total operating and maintenance expense increase | $ 38 |

***Depreciation and Amortization*** — Depreciation and amortization expense increased $21 million, or 5.4 percent, for the first six months of 2006, compared with the same period in 2005. The increase is due to normal plant additions and a recently approved change in decommissioning accruals resulting in an additional depreciation expense of $9.7 million year-to-date.

***Income taxes*** — Income taxes for continuing operations increased by $4.3 million for the first six months of 2006, compared with 2005. The increase in income taxes was primarily due to an increase in pre-tax earnings partially offset by a tax benefit of $17.5 million for the first six months of 2006 for capital loss carry forwards, as previously discussed. The effective tax rate for continuing operations was 23.0 percent for the first six months of 2006, compared with 25.6 percent for the same period in 2005. The reduction in the effective tax rate was primarily due to the tax benefit for capital loss carry forwards.

**Factors Affecting Results of Continuing Operations**

***Fuel Supply and Costs***

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.

***Regulation***

For a general discussion of the MISO Day 2 market and 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 the 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.

**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 regulation. At June 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 June 30, 2006, the VaRs for the commodity trading operations were:

| (Millions of Dollars) | Period Ended June 30, 2006 | Change from Period Ended March 31, 2006 | VaR Limit | Average | High | Low |
|---|---|---|---|---|---|---|
| Commodity Trading (1) | $ 1.69 | $ 0.27 | $ 5.00 | $ 1.31 | $ 2.12 | $ 0.29 |

(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 June 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 six months ended June 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):

| (Millions of Dollars) | Six months ended June 30, 2006 | Six months ended June 30, 2005 |
|---|---|---|
| Fair value of contracts outstanding at Jan. 1 | $ 3.9 | $ — |
| Contracts realized or otherwise settled during the period | (1.3) | (6.1) |
| Fair value of trading contract additions and changes during the period | 6.8 | 6.9 |
| Fair value of contracts outstanding at June 30 | $ 9.4 | $ 0.8 |

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

***Commodity Trading Contracts***

| (Thousands of Dollars) | Futures/Forwards Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity Greater Than 5 Years | Total Futures/ Forwards Fair Value |
|---|---|---|---|---|---|---|
| NSP-Minnesota | 1 | $ (104) | $ — | $ — | $ — | $ (104) |
| | 2 | 585 | 1,821 | — | — | 2,406 |
| PSCo | 1 | 1,986 | — | — | — | 1,986 |
| | 2 | 3,648 | 759 | — | — | 4,407 |
| Total Futures/Forwards Fair Value | | $ 6,115 | $ 2,580 | $ — | $ — | $ 8,695 |

| (Thousands of Dollars) | Options Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity Greater Than 5 Years | Total Options Fair Value |
|---|---|---|---|---|---|---|
| PSCo | 2 | $ 1,711 | $ (1,040) | $ — | $ — | $ 671 |
| Total Options Fair Value | | $ 1,711 | $ (1,040) | $ — | $ — | $ 671 |

***Commodity Hedge Contracts***

| (Thousands of Dollars) | Futures/Forwards Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity Greater Than 5 Years | Total Futures/ Forwards Fair Value |
|---|---|---|---|---|---|---|
| NSP-Minnesota | 2 | $ 52,861 | $ — | $ — | $ — | $ 52,861 |
| PSCo | 1 | 98 | — | — | — | 98 |
| Total Futures/Forwards Fair Value | | $ 52,959 | $ — | $ — | $ — | $ 52,959 |

| | | Options | | | | |
|---|---|---|---|---|---|---|
| (Thousands of Dollars) | Source of Fair Value | Maturity Less Than 1 Year | Maturity 1 to 3 Years | Maturity 4 to 5 Years | Maturity Greater Than 5 Years | Total Options Fair Value |
| NSP-Minnesota | 2 | $ (1,978) | $ — | $ — | $ — | $ (1,978) |
| PSCo | 2 | (9,926) | 892 | — | — | (9,034) |
| NSP-Wisconsin | 2 | 116 | — | — | — | 116 |
| Total Options Fair Value | | $ (11,788) | $ 892 | $ — | $ — | $ (10,896) |

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

2 — Prices based on models and other valuation methods.

These represent the fair value of positions calculated using internal models when directly and indirectly quoted external prices or prices derived from external sources are not available. Internal models incorporate the use of options pricing and estimates of the present value of cash flows based upon underlying contractual terms. The models reflect management's estimates, taking into account observable market prices, estimated market prices in the absence of quoted market prices, the risk-free market discount rate, volatility factors, estimated correlations of commodity prices and contractual volumes. Market price uncertainty and other risks also are factored into the 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 June 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 $0.7 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 June 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 $7.7 million annually, or approximately $1.9 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 June 30, 2006, a 10-percent increase in prices would have resulted in a net mark-to-market increase in credit risk exposure of $13.9 million, while a decrease of 10-percent would have resulted in a decrease of $12.4 million.

## LIQUIDITY AND CAPITAL RESOURCES

**Cash Flows**

| (Millions of Dollars) | Six months ended June 30, 2006 | Six months ended June 30, 2005 |
|---|---|---|
| Cash provided by operating activities | | |
| Continuing operations | $ 1,145 | $ 690 |
| Discontinued operations | 76 | 107 |
| Total | $ 1,221 | $ 797 |