ST MARY LAND & EXPLORATION CO
Form 10-Q
November 02, 2007

**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 September 30, 2007

Commission file number 001-31539

**ST. MARY LAND & EXPLORATION COMPANY**
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| Delaware<br>(State or other jurisdiction of incorporation or organization) | 41-0518430<br>(I.R.S. Employer Identification No.) |
| 1776 Lincoln Street, Suite 700, Denver, Colorado<br>(Address of principal executive offices) | 80203<br>(Zip Code) |

(303) 861-8140
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes þ No o

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 þ Accelerated filer o Non-accelerated filer o

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

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

As of October 26, 2007, the registrant had 62,873,327 shares of common stock, $0.01 par value, outstanding.

ST. MARY LAND & EXPLORATION COMPANY

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**PART I. FINANCIAL INFORMATION**
**ITEM 1. FINANCIAL STATEMENTS**

**ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES**
**CONSOLIDATED BALANCE SHEETS (UNAUDITED)**
**(In thousands, except share amounts)**

| **ASSETS** | September 30, 2007 | December 31, 2006 |
|---|---|---|
| Current assets: | | |
| Cash and cash equivalents | $ 17,240 | $ 1,464 |
| Short-term investments | 1,158 | 1,450 |
| Accounts receivable | 150,699 | 142,721 |
| Refundable income taxes | 3,097 | 7,684 |
| Prepaid expenses and other | 18,587 | 17,485 |
| Accrued derivative asset | 32,045 | 56,136 |
| Deferred income taxes | 4,186 | - |
| Total current assets | 227,012 | 226,940 |
| | | |
| Property and equipment (successful efforts method), at cost: | | |
| Proved oil and gas properties | 2,405,243 | 2,063,911 |
| Less - accumulated depletion, depreciation, and amortization | (753,914) | (630,051) |
| Unproved oil and gas properties, net of impairment allowance of $10,210 in 2007 and $9,425 in 2006 | 117,493 | 100,118 |
| Wells in progress | 154,430 | 97,498 |
| Oil and gas properties held for sale less accumulated depletion, depreciation, and amortization | 74,076 | - |
| Other property and equipment, net of accumulated depreciation of $11,298 in 2007 and $9,740 in 2006 | 9,074 | 6,988 |
| | 2,006,402 | 1,638,464 |
| | | |
| Noncurrent assets: | | |
| Goodwill | 9,452 | 9,452 |
| Accrued derivative asset | 14,775 | 16,939 |
| Other noncurrent assets | 28,360 | 7,302 |
| Total noncurrent assets | 52,587 | 33,693 |
| | | |
| **Total Assets** | **$ 2,286,001** | **$ 1,899,097** |
| | | |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable and accrued expenses | $ 236,044 | $ 171,834 |
| Short-term note payable | - | 4,469 |
| Accrued derivative liability | 43,796 | 13,100 |
| Deferred income taxes | - | 14,667 |
| Total current liabilities | 279,840 | 204,070 |

| | | | | |
|---|---|---|---|---|
| Noncurrent liabilities: | | | | |
| Long-term credit facility | | 155,000 | | 334,000 |
| Senior convertible notes | | 287,500 | | 99,980 |
| Asset retirement obligation | | 77,258 | | 77,242 |
| Asset retirement obligation associated with oil and gas properties held for sale | | 7,827 | | - |
| Net Profits Plan liability | | 167,531 | | 160,583 |
| Deferred income taxes | | 281,250 | | 224,518 |
| Accrued derivative liability | | 88,111 | | 46,432 |
| Other noncurrent liabilities | | 8,490 | | 8,898 |
| Total noncurrent liabilities | | 1,072,967 | | 951,653 |
| | | | | |
| Commitments and contingencies | | | | |
| | | | | |
| Stockholders' equity: | | | | |
| Common stock, $0.01 par value: authorized - 200,000,000 shares; | | | | |
| issued: 63,733,590 shares in 2007 and 55,251,733 shares in 2006; | | | | |
| outstanding, net of treasury shares: 62,725,278 shares in 2007 | | | | |
| and 55,001,733 shares in 2006 | | 637 | | 553 |
| Additional paid-in capital | | 163,080 | | 38,940 |
| Treasury stock, at cost: 1,008,312 shares in 2007 and 250,000 shares in 2006 | | (29,126) | | (4,272) |
| Retained earnings | | 845,786 | | 695,224 |
| Accumulated other comprehensive income (loss) | | (47,183) | | 12,929 |
| Total stockholders' equity | | 933,194 | | 743,374 |
| | | | | |
| **Total Liabilities and Stockholders' Equity** | **$** | **2,286,001** | **$** | **1,899,097** |

The accompanying notes are an integral part of these consolidated financial statements.

**ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)**
**(In thousands, except per share amounts)**

| | For the Three Months Ended September 30, 2007 | For the Three Months Ended September 30, 2006 | For the Nine Months Ended September 30, 2007 | For the Nine Months Ended September 30, 2006 |
|---|---|---|---|---|
| Operating revenues: | | | | |
| Oil and gas production revenue | $ 228,497 | $ 188,159 | $ 638,357 | $ 550,181 |
| Realized oil and gas hedge gain | 10,173 | 4,828 | 36,160 | 14,808 |
| Marketed gas system revenue | 7,414 | 3,852 | 31,240 | 13,086 |
| Gain on sale of proved properties | - | 801 | - | 7,233 |
| Other revenue | 603 | 400 | 9,090 | (299) |
| Total operating revenues | 246,687 | 198,040 | 714,847 | 585,009 |
| | | | | |
| Operating expenses: | | | | |
| Oil and gas production expense | 54,970 | 44,998 | 157,618 | 129,490 |
| Depletion, depreciation, amortization, and asset retirement obligation liability accretion | 59,061 | 39,817 | 162,677 | 110,118 |
| Exploration | 15,257 | 9,766 | 49,669 | 35,872 |
| Impairment of proved properties | - | 5,259 | - | 6,548 |
| Abandonment and impairment of unproved properties | 937 | 920 | 3,886 | 3,368 |
| General and administrative | 13,110 | 9,725 | 37,948 | 30,940 |
| Change in Net Profits Plan liability | 3,143 | (3,710) | 6,948 | 17,370 |
| Marketed gas system expense | 7,278 | 3,133 | 29,454 | 11,149 |
| Unrealized derivative loss (gain) | (2,880) | 68 | 2,224 | 5,329 |
| Other expense | 460 | 842 | 1,577 | 1,832 |
| Total operating expenses | 151,336 | 110,818 | 452,001 | 352,016 |
| | | | | |
| Income from operations | 95,351 | 87,222 | 262,846 | 232,993 |
| | | | | |
| Nonoperating income (expense): | | | | |
| Interest income | 355 | 90 | 612 | 1,454 |
| Interest expense | (4,082) | (2,170) | (13,885) | (5,098) |
| | | | | |
| Income before income taxes | 91,624 | 85,142 | 249,573 | 229,349 |
| Income tax expense | (33,971) | (29,265) | (92,735) | (82,866) |
| | | | | |
| **Net income** | **$ 57,653** | **$ 55,877** | **$ 156,838** | **$ 146,483** |
| | | | | |
| Basic weighted-average common shares outstanding | 63,424 | 55,398 | 61,364 | 56,564 |
| | | | | |
| Diluted weighted-average common shares outstanding | 64,727 | 64,926 | 64,917 | 66,332 |
| | | | | |
| **Basic net income per common share** | **$ 0.91** | **$ 1.01** | **$ 2.56** | **$ 2.59** |
| | | | | |
| **Diluted net income per common share** | **$ 0.89** | **$ 0.88** | **$ 2.43** | **$ 2.25** |

The accompanying notes are an integral part of these consolidated financial statements.

**ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME**
**(UNAUDITED)**
**(In thousands, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Additional Paid-in Capital | Treasury Stock Shares | Treasury Stock Amount | Deferred Stock-Based Compensation | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Stockholders' Equity |
|---|---|---|---|---|---|---|---|---|---|
| **Balances, December 31, 2005** | **57,011,740** | **$ 570** | **$ 123,278** | **(250,000)** | **$ (5,148)** | **$ (5,593)** | **$ 510,812** | **$ (54,599)** | **$ 569,320** |
| Comprehensive income, net of tax: | | | | | | | | | |
| Net income | - | - | - | - | - | - | 190,015 | - | 190,015 |
| Change in derivative instrument fair value | - | - | - | - | - | - | - | 87,107 | 87,107 |
| Reclassification to earnings | - | - | - | - | - | - | - | (18,129) | (18,129) |
| Minimum pension liability adjustment | - | - | - | - | - | - | - | (180) | (180) |
| Total comprehensive income | | | | | | | | | 258,813 |
| SFAS No. 158 transition amount | - | - | - | - | - | - | - | (1,270) | (1,270) |
| Cash dividends, $ 0.10 per share | - | - | - | - | - | - | (5,603) | - | (5,603) |
| Treasury stock purchases | - | - | - | (3,319,300) | (123,108) | - | - | - | (123,108) |
| Retirement of treasury stock | (3,275,689) | (33) | (122,598) | 3,275,689 | 122,631 | - | - | - | - |
| Issuance of common stock under Employee Stock Purchase Plan | 26,046 | - | 814 | - | - | - | - | - | 814 |
| Sale of common stock, including income | 1,489,636 | 16 | 32,970 | - | - | - | - | - | 32,986 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| tax benefit of stock option exercises | | | | | | | | | |
| Adoption of Statement of Financial Accounting | | | | | | | | | |
| Standards No. 123(R) | - | - | (5,593) | - | - | 5,593 | - | - | - |
| Stock-based compensation expense | - | - | 10,069 | 43,611 | 1,353 | - | - | - | 11,422 |
| **Balances, December 31, 2006** | **55,251,733** | **$ 553** | **$ 38,940** | **(250,000)** | **$ (4,272)** | **$ -** | **$ 695,224** | **$ 12,929** | **$ 743,374** |
| Comprehensive income, net of tax: | | | | | | | | | |
| Net income | - | - | - | - | - | - | 156,838 | - | 156,838 |
| Change in derivative instrument fair value | - | - | - | - | - | - | - | (37,420) | (37,420) |
| Reclassification to earnings | - | - | - | - | - | - | - | (22,688) | (22,688) |
| Minimum pension liability adjustment | - | - | - | - | - | - | - | (4) | (4) |
| Total comprehensive income | | | | | | | | | 96,726 |
| Cash dividends, $ 0.10 per share | - | - | - | - | - | - | (6,276) | - | (6,276) |
| Treasury stock purchases | - | - | - | (790,816) | (25,904) | - | - | - | (25,904) |
| Issuance of common stock under Employee | | | | | - | | | | |
| Stock Purchase Plan | 14,622 | - | 455 | - | - | - | - | - | 455 |
| Conversion of 5.75% Senior Convertible Notes | | | | | | | | | |
| due 2022 to common stock, including income | | | | | | | | | |
| tax benefit of conversion | 7,692,295 | 77 | 107,160 | - | - | - | - | - | 107,237 |
| Issuance of common stock upon settlement of | | | | | | | | | |
| RSUs following expiration of restriction period, | | | | | | | | | |
| | 302,370 | 3 | (4,569) | - | - | - | - | - | (4,566) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| net of shares used for tax withholdings | | | | | | | | | |
| Sale of common stock, including income tax benefit of stock option exercises | 471,320 | 4 | 13,538 | - | - | - | - | - | 13,542 |
| Stock-based compensation expense | 1,250 | - | 7,556 | 32,504 | 1,050 | - | - | - | 8,606 |
| **Balances, September 30, 2007** | **63,733,590** | **$ 637** | **$ 163,080** | **(1,008,312)** | **$ (29,126)** | **$ -** | **$ 845,786** | **$ (47,183)** | **$ 933,194** |

The accompanying notes are an integral part of these consolidated financial statements.

**ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)**
**(In thousands)**

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | 2007 | 2006 |
| Reconciliation of net income to net cash provided by operating activities: | | |
| Net income | $ 156,838 | $ 146,483 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Gain on insurance settlement | (6,340) | - |
| Gain on sale of proved properties | - | (7,233) |
| Depletion, depreciation, amortization, and asset retirement obligation liability accretion | 162,677 | 110,118 |
| Exploratory dry hole expense | 12,714 | 4,033 |
| Abandonment and impairment of unproved properties | 3,886 | 9,915 |
| Unrealized derivative loss | 2,224 | 5,329 |
| Change in Net Profits Plan liability | 6,948 | 17,370 |
| Stock-based compensation expense | 8,606 | 8,979 |
| Deferred income taxes | 79,289 | 64,612 |
| Other | (5,168) | 398 |
| Changes in current assets and liabilities: | | |
| Accounts receivable | (208) | 30,810 |
| Refundable income taxes | 4,587 | (21,495) |
| Prepaid expenses and other | 28,035 | (15,048) |
| Accounts payable and accrued expenses | 27,552 | (21,612) |
| Income tax benefit from the exercise of stock options | (7,658) | (15,110) |
| **Net cash provided by operating activities** | **473,982** | **317,549** |
| | | |
| Cash flows from investing activities: | | |
| Proceeds from insurance settlement | 7,064 | - |
| Proceeds from sale of oil and gas properties | 324 | 1,183 |
| Capital expenditures | (500,111) | (293,977) |
| Acquisition of oil and gas properties | (32,650) | (9,933) |
| Deposits for acquisition of oil and gas assets | (15,310) | - |
| Deposits to short-term investments available-for-sale | (1,153) | - |
| Receipts from short-term investments available-for-sale | 1,450 | - |
| Other | 29 | 79 |
| **Net cash used in investing activities** | **(540,357)** | **(302,648)** |
| | | |
| Cash flows from financing activities: | | |
| Proceeds from credit facility | 553,914 | 338,000 |
| Repayment of credit facility | (732,914) | (272,000) |
| Repayment of short-term note payable | (4,469) | - |
| Income tax benefit from the exercise of stock options | 7,658 | 15,110 |
| Proceeds from issuance of senior convertible debt - net | 280,664 | - |
| Proceeds from sale of common stock | 6,342 | 16,046 |
| Repurchase of common stock | (25,904) | (123,108) |
| Dividends paid | (3,140) | (2,858) |

| | | |
|---|---|---|
| **Net cash provided by (used in) financing activities** | **82,151** | **(28,810)** |
| | | |
| Net change in cash and cash equivalents | 15,776 | (13,909) |
| Cash and cash equivalents at beginning of period | 1,464 | 14,925 |
| **Cash and cash equivalents at end of period** | **$ 17,240** | **$ 1,016** |

The accompanying notes are an integral part of these consolidated financial statements.

**ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)**
**(Continued)**

Supplemental schedule of additional cash flow information and noncash investing and financing activities:

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | 2007 | 2006 |
| | (in thousands) | |
| Cash paid for interest, net of capitalized interest | $ 13,476 | $ 8,157 |
| Cash paid or (refunded) for income taxes | $ (1,048) | $ 29,849 |

Dividends of approximately $3.2 million have been declared by the Company's Board of Directors, but not paid,
as of September 30, 2007.

As of September 30, 2007, and 2006, $103.1 million and $90.5 million, respectively, are included as additions
to oil and gas properties and as increases in accounts payable and accrued expenses. These oil and
gas property additions are reflected in cash used in investing activities in the periods that the payables are settled.

In May 2007 and 2006 and July 2007 and 2006 the Company issued 26,292, 26,076, 6,212 and 3,751 shares,
respectively, of common stock from treasury to its non-employee directors pursuant to the Company's non-employee director stock compensation plan. The Company recorded compensation expense related to issuances of shares to non-employee directors of $855,000 and $465,000 for the nine-month periods ended
September 30, 2007, and 2006, respectively.

In March 2007 the Company called the 5.75% Senior Convertible Notes for redemption. The note
holders elected to convert the 5.75% Senior Convertible Notes to common stock. As a result, the
Company issued 7,692,295 shares of common stock on March 16, 2007, in exchange for the $100
million of 5.75% Senior Convertible Notes. The conversion was executed in accordance with the
conversion provisions of the original indenture. Additionally, the conversion resulted in a $7.0 million decrease in non-current deferred income taxes and a corresponding increase in additional

paid-in capital that is a result of the recognition of the cumulative excess tax benefit earned by the Company associated with the contingent interest feature of this note.

In June 2006 the Company hired a new senior executive. In doing so, the Company issued 13,784 shares of stock and recorded compensation expense of approximately $728,000. Additionally, in March 2007 the Company issued 1,250 shares of stock to the senior executive as the Company reached certain performance levels. The Company has recognized approximately $93,000 of expense related to this issuance as of September 30, 2007.

In February 2007 and 2006 the Company issued 78,657 and 484,351 restricted stock units, respectively, pursuant to the Company's Restricted Stock Plan. The total value of the issuances were $2.5 million and $16.4 million, respectively.

In May 2006 the Company closed a transaction whereby it exchanged oil and gas properties located in Richland County, Montana for non-core oil and gas properties. This transaction is considered a non-monetary exchange for accounting purposes with a fair value assigned to this transaction of $11.5 million.

The accompanying notes are an integral part of these consolidated financial statements.

**ST. MARY LAND & EXPLORATION COMPANY AND SUBSIDIARIES**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**
**(UNAUDITED)**

**September 30, 2007**

**Note 1 – The Company and Business**

St. Mary Land & Exploration Company ("St. Mary" or the "Company") is an independent energy company engaged in the exploration, exploitation, development, acquisition, and production of natural gas and crude oil. The Company's operations are conducted in the continental United States and offshore in the Gulf of Mexico.

**Note 2 - Basis of Presentation and Significant Accounting Policies**

*Basis of Presentation*

The accompanying unaudited condensed consolidated financial statements of St. Mary have been prepared in accordance with accounting principles generally accepted in the United States for interim financial information. They do not include all information and notes required by generally accepted accounting principles for complete financial statements. Except as disclosed herein, there has been no material change in the information disclosed in the notes to consolidated financial statements included in St. Mary's Annual Report on Form 10-K/A for the year ended December 31, 2006. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation of the interim financial information have been included. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

*Other Significant Accounting Policies*

The accounting policies followed by the Company are set forth in Note 1 to the Company's consolidated financial statements in the Form 10-K/A for the year ended December 31, 2006, and are supplemented throughout the footnotes of this document. It is suggested that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and notes included in the Form 10-K/A for the year ended December 31, 2006.

**Note 3 – Acquisitions, Divestitures, and Assets Held for Sale**

*Catarina Field Acquisition*

On June 1, 2007, the Company acquired oil and gas properties located primarily in the Catarina Field in Webb County, Texas in exchange for $29.0 million of cash. The Company allocated $29.0 million to proved and unproved oil and gas properties. The Company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The final purchase price will be adjusted for normal net purchase price adjustments and is expected to be finalized during the fourth quarter of 2007. The acquisition was accounted for using the purchase method and was funded with cash on hand and borrowings under the Company's credit facility.

*Permian Basin Acquisition*

On December 14, 2006, the Company acquired oil and gas properties in the Permian Basin in West Texas from private parties in exchange for $247.4 million of cash. After normal net purchase price adjustments of approximately $4.3 million, $239.8 million was allocated to proved and unproved oil and gas properties and $3.0 million was allocated to intangible assets. The net difference between cash exchanged and the amount allocated to oil and gas properties and intangible assets was allocated to other assets. The Company allocated the purchase price based on the estimated fair value of the assets and liabilities acquired. The acquisition was accounted for using the purchase method and was funded with cash on hand and borrowings under the Company's credit facility.

*Richland County, Montana Acquisition*

On May 15, 2006, the Company closed on a transaction whereby it exchanged oil and gas properties located in the Uinta Basin for oil and gas properties located in Richland County, Montana. The transaction was structured as an Internal Revenue Code Section 1031 tax-deferred exchange. For financial reporting purposes, the transaction is considered a non-monetary exchange and was accounted for at estimated fair value. The exchange of properties resulted in recognition of approximately $6.4 million of gain.

*Assets Held for Sale*

On September 13, 2007, the Company announced that it had engaged an outside firm to market for sale certain non-core oil and gas properties located primarily in the Rocky Mountain and Mid-Continent regions. In accordance with Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets", these properties have been separately presented in the balance sheet at the lower of net book value or fair value less the cost to sell. These assets are now classified as oil and gas properties held for sale on the consolidated balance sheet as of September 30, 2007. Asset retirement obligation liabilities related to these properties have also been reclassified to liabilities associated with oil and gas properties held for sale on the consolidated balance sheet as of September 30, 2007. If these properties had not been classified as held for sale, depletion, depreciation, amortization, and asset retirement obligation accretion expense would have been higher by approximately $428,000 for both the three-month and nine-month periods ended September 30, 2007.

Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held-for-sale, long-lived assets are no longer depreciated or depleted and a measurement for impairment is performed to expense any excess of carrying value over fair value less costs to sell.

**Note 4 – Earnings per Share**

Basic net income per common share of stock is calculated by dividing net income available to common stockholders by the weighted-average basic common shares outstanding for the respective period. The shares represented by vested restricted stock units ("RSUs") are included in the calculation of the weighted-average basic common shares outstanding. The earnings per share calculations reflect the impact of any repurchases of shares of common stock made by the Company.

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average diluted common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for the earnings per share calculations consist of in-the-money outstanding stock options to purchase the Company's common stock, shares into which the 5.75% Senior Convertible Notes due 2022 (the "5.75% Convertible Notes") were convertible for the periods those notes were outstanding, shares into which the 3.50% Senior Convertible Notes due 2027 (the "3.50% Convertible Notes") are convertible, and unvested RSUs. The shares underlying the unvested grants of RSUs are included in the diluted earnings per share calculation beginning with grant date of the RSUs. Following the lapse of restriction periods, the shares underlying the units are issued and therefore are included in the number of issued and outstanding shares.

Prior to the conversion of the Company's 5.75% Convertible Notes on March 16, 2007, potentially dilutive shares associated with this instrument were accounted for using the if-converted method for the determination of diluted earnings per share.  Adjusted net income used in the if-converted method was derived by adding interest expense paid on the 5.75% Convertible Notes back to net income and then adjusting for nondiscretionary items that are based on net income and would have changed had the 5.75% Convertible Notes been converted at the beginning of the period.  The 5.75% Convertible Notes were called for redemption by the Company on March 16, 2007, and all of the note holders elected to convert the notes to shares of the Company's common stock.  The Company issued 7.7 million common shares in connection with the conversion of the 5.75% Convertible Notes.  Upon conversion, these shares were included in the calculation of weighted-average common shares outstanding.  The diluted earnings per share calculation for the nine-month period ended September 30, 2007, was adjusted for the conversion and included a time-weighted average of approximately 2.1 million potentially dilutive shares related to the 5.75% Convertible Notes.  No potentially dilutive shares related to the 5.75% Convertible Notes were included in the three-month period ended September 30, 2007, as the 5.75% Convertible Notes were not outstanding during the current quarter period.  The Company's 3.50% Convertible Notes have a net-share settlement right, and the treasury stock method is used to measure the potentially dilutive impact of shares associated with the conversion feature.  The 3.50% Convertible Notes issued April 4, 2007, have not been dilutive for the entire time they have been outstanding and therefore do not impact the diluted earnings per share calculation for the three-month and nine-month periods ended September 30, 2007.

The dilutive effect of stock options and unvested RSUs is considered in the detailed calculations below.  There were no anti-dilutive securities related to stock options or RSUs for the three-month or nine-month periods ended September 30, 2006.  There were no other anti-dilutive securities for the three-month or nine-month periods ended September 30, 2007.

The following table sets forth the calculation of basic and diluted earnings per share:

| | For the Three Months Ended September 30, 2007 | 2006 | For the Nine Months Ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| | (In thousands, except per share amounts) | | | |
| Net income | $ 57,653 | $ 55,877 | $ 156,838 | $ 146,483 |
| Adjustments to net income for dilution: | | | | |
| Add: Interest expense not incurred if 5.75% Convertible Notes converted | - | 1,597 | 1,284 | 4,740 |
| Less: Other adjustments | - | (16) | (13) | (47) |
| Less: Income tax effect of adjustment items | - | (543) | (471) | (1,696) |
| Net income adjusted for the effect of dilution | $ 57,653 | $ 56,915 | $ 157,638 | $ 149,480 |
| Basic weighted-average common shares outstanding | 63,424 | 55,398 | 61,364 | 56,564 |
| Add: Dilutive effect of stock options and unvested restricted stock units | 1,303 | 1,836 | 1,471 | 2,076 |
| Add: Dilutive effect of 5.75% Convertible Notes using if-converted method | - | 7,692 | 2,082 | 7,692 |
| Diluted weighted-average common shares outstanding | 64,727 | 64,926 | 64,917 | 66,332 |
| Basic net income per common share | $ 0.91 | $ 1.01 | $ 2.56 | $ 2.59 |
| Diluted net income per common share | $ 0.89 | $ 0.88 | $ 2.43 | $ 2.25 |

**Note 5 – Compensation Plans**

*Cash Bonus Plan*

The Company has a cash bonus plan under which the Company can award participants a cash bonus of up to 50 percent of their aggregate base salary. Any awards under the cash bonus plan are based on Company and regional performance, and then are further refined by individual performance. The Company accrues cash bonus expense related to the current year's performance. Included in the general and administrative and exploration expense line items in the consolidated statements of operations are $1.3 million and $474,000 of cash bonus expense related to the specific performance year for the three-month periods ended September 30, 2007, and 2006, respectively, and $3.8 million and $2.8 million for the nine-month periods ended September 30, 2007, and 2006, respectively.

*Equity Incentive Compensation Plan*

There are several current and historical components to the equity incentive compensation plan that are described in this section. Various types of equity awards have been granted by the Company in different periods. This section addresses the disclosure requirements for all equity awards currently outstanding.

Effective January 1, 2006, the Company adopted SFAS No. 123(R), "Share Based Payment" ("SFAS No.123(R)"), using the modified-prospective transition method. Under that transition method, compensation expense that must be recognized in periods subsequent to January 1, 2006, includes: (a) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS No. 123, " Accounting for Stock-Based Compensation", and (b) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the grant date fair value estimated in accordance with the provisions of SFAS No. 123(R).

As of September 30, 2007, 2.4 million shares of common stock remained available for grant under the Company's 2006 Equity Incentive Compensation Plan (the "2006 Equity Plan"). Any issuances of a full value direct share benefit such as an outright grant of common stock, a grant of a restricted share or a restricted stock unit counts as two shares against the amount eligible to be granted under the 2006 Equity Plan. Each stock option and similar instrument granted counts as one share against the eligible shares authorized to be issued under the 2006 Equity Plan.

The following sections describe the details of RSUs and stock options outstanding as of September 30, 2007.

*Restricted Stock Incentive Program Under the 2006 Equity Incentive Compensation Plan*

The Company has a long-term incentive program whereby grants of restricted stock or RSUs have been awarded to eligible employees, consultants, and members of the Board of Directors. Restrictions and vesting periods for the awards are determined at the discretion of the Board of Directors and are set forth in the award agreements. Each RSU represents a right for one share of the Company's common stock to be delivered upon settlement of the award at the end of a specified period. For employees, these grants are determined annually based on a performance formula consistent with the cash bonus plan.

St. Mary issued 78,657 RSUs on February 28, 2007, related to 2006 performance and 484,351 RSUs on February 28, 2006, related to 2005 performance. The total fair value associated with these issuances was $2.5 million in 2007 and $16.4 million in 2006 as measured on the respective grant dates. The granted RSUs vest 25 percent immediately upon grant and 25 percent on each of the first three anniversary dates of the grant. The awards are restricted, and the shares underlying the RSUs are not issued as common shares until the third anniversary of the grant. Compensation expense is recorded monthly over the vesting period of the award. Accordingly, the Company recorded expense in 2005 related to the awards issued in 2006, recorded expense in 2006 related to the awards issued in 2007, and is recording expense over the earning determination period in 2007 for grants that will be issued in 2008. Vested shares of common stock underlying the RSU grants will be issued on the third anniversary of the grants, at which time the shares carry no further restrictions. For all grants made subsequent to and including the 2006 grant period, the Company is using the accelerated amortization method as described in Financial Accounting Standards Board ("FASB") Interpretation No. 28, "Accounting for Stock Appreciation Rights and Other Variable Stock Option or Award Plans—an interpretation of APB Opinions No. 15 and 25," whereby approximately 47 percent of the total estimated compensation expense is recognized in the first year of the vesting period. Expense for grants made for plan years prior to 2006 is being amortized under the straight-line method since that method was previously utilized by the Company and was allowed prior to the adoption of SFAS No. 123(R).

St. Mary also issued 20,007 RSUs and 5,000 RSUs for various grants to specific employees during the nine months ended September 30, 2007, and 2006, respectively. These grants have various vesting schedules. The fair value of these awards will be recorded to compensation expense over the respective vesting periods using the same basic framework as described above.

On June 30, 2007, the Company converted 427,059 RSUs, which were granted on June 30, 2004, into common stock. The Company and the majority of the grant participants mutually agreed to net share settle the awards to cover income and payroll tax withholdings as provided for in the plan document and award agreements. As a result, the Company issued a net 302,370 shares of common stock associated with this grant. The remaining 124,689 shares were withheld to offset tax withholding obligations that occurred upon the delivery of the shares underlying those RSUs.

As of September 30, 2007, there were a total of 693,349 RSUs outstanding, of which 390,804 were vested. Total compensation expense related to the RSUs for the three-month periods ended September 30, 2007, and 2006, was $2.1 million and $1.6 million respectively, and the total compensation expense related to the RSUs for the nine-month periods ended September 30, 2007, and 2006, was $7.1 million and $6.9 million respectively. There is $2.8 million included in compensation expense for the nine-month period ended September 30, 2007, for the first 25 percent vesting of the estimated value of grants expected to be issued in 2008 related to the 2007 performance year. As of September 30, 2007, there was $5.0 million of total unrecognized compensation expense related to unvested restricted stock unit awards. The unrecognized compensation expense is being amortized over each grant's respective vesting period through 2010.

In measuring compensation expense from the grant of RSUs, SFAS No. 123(R) requires companies to estimate the fair value of the award on the grant date. The fair value of an RSU is inherently less than the market value of an unrestricted security. The fair value of RSUs has been measured using the Black-Scholes option pricing model. The Company's computation of expected volatility is based on the historic volatility of St. Mary's common stock. The Company's computation of expected life is determined based on historical experience of similar awards, giving consideration to the contractual terms of the stock-based awards, vesting schedules, and expectations of future employee behavior. The interest rate for periods within the contractual life of the award is based on the U.S. Treasury constant maturity yield at the time of grant. The fair values of granted RSUs were estimated using the following weighted-average assumptions:

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | 2007 | 2006 |
| Risk free interest rate: | 4.6% | 4.7% |
| Dividend yield: | 0.3% | 0.3% |
| Volatility factor of the market price of the Company's common stock: | 32.2% | 36.6% |
| Expected life of the awards (in years): | 3 | 3 |

A summary of the status and activity of non-vested RSUs for the nine-month period ended September 30, 2007, is presented below.

| | Non-Vested RSUs | Weighted-Average Grant-Date Fair Value |
|---|---|---|
| Non-vested as of December 31, 2006 | 506,161 | $ 28.92 |
| Granted | 98,664 | $ 32.30 |
| Vested | (264,048) | $ 25.98 |
| Forfeited | (38,232) | $ 31.44 |
| Non-vested as of September 30, 2007 | 302,545 | $ 32.26 |

*Stock Option Grants Under the 2006 Equity Incentive Compensation Plan*

The Company previously granted stock options under the St. Mary Land & Exploration Company Stock Option Plan and Incentive Stock Option Plan. The last issuance of stock options was December 31, 2004. Stock options to purchase shares of the Company's common stock had been issued to eligible employees and members of the Board of Directors. All options granted to date under the option plans were granted at exercise prices equal to the respective closing market price of the Company's common stock on the grant dates, which generally occurred on the last day of a fiscal period. All stock options granted under the option plans are exercisable for a period of up to ten years from the date of grant.

During the three-month periods ended September 30, 2007, and 2006, the Company recognized stock-based compensation expense of approximately $27,000 and $623,000, respectively, related to stock options that were outstanding as of January 1, 2006. During the nine-month periods ended September 30, 2007, and 2006, the Company recognized stock-based compensation expense of approximately $409,000 and $1.6 million, respectively, related to stock options that were outstanding as of January 1, 2006. There was no cumulative effect adjustment from the adoption of SFAS No. 123(R).

The following table summarizes the stock options outstanding as of September 30, 2007, and activity for the nine-month period then ended.

| | Options | Weighted-Average Exercise Price | Weighted-Average Remaining Contractual Term (In years) | Aggregate Intrinsic Value (In thousands) |
|---|---|---|---|---|
| Outstanding, beginning of period | 3,121,602 | $ 12.56 | | |
| Exercised | (471,320) | $ 12.48 | | |
| Forfeited | (2,452) | $ 7.34 | | |
| Outstanding, end of period | 2,647,830 | $ 12.58 | 4.62 | $ 61,150 |
| Vested, or expected to vest, end of period | 2,647,830 | | | $ 61,150 |
| Exercisable, end of period | 2,628,115 | $ 12.54 | 4.61 | $ 60,798 |

As of September 30, 2007, there was $44,000 of total unrecognized compensation cost related to unvested stock option awards.

The fair value of options was measured at the date of grant using the Black-Scholes option pricing model. There were no stock options granted during the nine-month period ended September 30, 2007.

*Net Profits Plan*

Under the Company's Net Profits Interest Bonus Plan (the "Net Profits Plan"), all oil and gas wells that are completed or acquired during a year are designated within a specific pool. Key employees recommended by senior management and designated as participants by the Company's Compensation Committee of the Board of Directors and employed by the Company on the last day of that year become entitled to payments under the Net Profits Plan after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, ten percent of future net cash flows generated by the pool are allocated among the participants and are distributed at least annually. The portion of net cash flows from the pool to be allocated among the participants increases to 20 percent after the Company has recovered 200 percent of the total costs for the pool, including payments made under the Net Profits Plan at the ten percent level. The Net Profits Plan has been in place since 1991. Pool years prior to and including 2005 are fully vested. Pool years beginning in 2006 carry a vesting period of three years whereby one-third is vested at the end of the year for which participation is designated and one-third vests on each of the following two anniversary dates. Beginning with the 2006 pool, the maximum benefit to full participants from a single year's pool is limited to 300 percent of a participating individual's adjusted base salary paid during the year to which the pool relates.

In a separate calculation, the Company records the estimated liability for future payments under the Net Profits Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a significant management estimate. For a predominate number of the pools, a discount rate of 15 percent is used to calculate this liability and is intended to represent the best estimate of the present value of expected future payments under the Net Profits Plan. The Company's estimate of its liability is highly dependent on the oil and natural gas price and cost assumptions and discount rates used in the calculations. The commodity price assumptions are formulated by applying a price that is derived from a rolling average of actual prices realized over the prior 24 months together with adjusted New York Mercantile Exchange ("NYMEX") strip prices for the ensuing 12 months for a total of 36 months of data. This average is adjusted to include the effect of hedge prices for the percentage of forecasted production hedged in the relevant period. The forecasted non-cash expense associated with this significant management estimate is highly volatile from period to period due primarily to fluctuations that occur in the crude oil and natural gas commodity markets. The Company continually evaluates the assumptions used in this calculation in order to include the current market environment for oil and natural gas prices, costs, discount rates, and overall market conditions.

The following table presents the changes in the estimated future liability attributable to the Net Profits Plan. Reductions in the liability relate to the realized results for the periods presented from oil and gas operations for the properties associated with the respective pools that have achieved payout status.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In thousands) | | (In thousands) | |
| Liability balance for Net Profits Plan as of the beginning of the period | $ 164,388 | $ 157,904 | $ 160,583 | $ 136,824 |
| Increase in liability | 11,383 | 3,043 | 28,906 | 37,937 |
| Reduction in liability for cash payments made or accrued and recognized as compensation expense | (8,240) | (6,752) | (21,958) | (20,566) |
| Liability balance for Net Profits Plan as of the end of the period | $ 167,531 | $ 154,195 | $ 167,531 | $ 154,195 |

The calculation of the estimated liability for the Net Profits Plan is highly sensitive to price estimates and discount rate assumptions. For example, if the commodity prices used in the calculation changed by five percent, the liability recorded at September 30, 2007, would differ by approximately $15 million. A one percentage point change in the discount rate would result in a change of the liability of approximately $10 million. Actual cash payments to be made in future periods are dependent on realized actual production, prices, and costs associated with the properties in each individual pool of the

Net Profits Plan. Consequently, actual cash payments will be inherently different from the amounts estimated.

The Company records changes in the present value of estimated future payments under the Net Profits Plan as a separate item in the consolidated statements of operations. The change in the estimated liability is recorded as a non-cash expense or benefit in the current period. The amount recorded as an expense or benefit associated with the change in the estimated liability is not allocated to general and administrative expense or exploration expense because it is associated with the future net cash flows from oil and gas properties in the respective pools rather than current period realized performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In thousands) | | (In thousands) | |
| General and administrative expense | $ 1,202 | $ (1,627) | $ 3,086 | $ 7,337 |
| Exploration expense | 1,941 | (2,083) | 3,862 | 10,033 |
| Total | $ 3,143 | $ (3,710) | $ 6,948 | $ 17,370 |

**Note 6 - Income Taxes**

Income tax expense for the three-month and nine-month periods ended September 30, 2007, and 2006, differs from the amount that would be provided by applying the statutory U.S. federal income tax rate to income before income taxes primarily due to the effect of state income taxes, percentage depletion, the estimated effect of the domestic production activities deduction, and other permanent differences.

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In thousands) | | (In thousands) | |
| Current portion of income tax expense (benefit): | | | | |
| Federal | $ 6,512 | $ (766) | $ 11,494 | $ 17,374 |
| State | 627 | 102 | 1,952 | 880 |
| Deferred portion of income tax expense: | 26,832 | 29,929 | 79,289 | 64,612 |
| Total income tax expense | $ 33,971 | $ 29,265 | $ 92,735 | $ 82,866 |
| Effective tax rates | 37.1% | 34.4% | 37.2% | 36.1% |

A change in tax rates between reported periods will generally reflect differences in the Company's estimated highest marginal state tax rates due to changes in the composition of income between state tax jurisdictions. Differences can also reflect various effects of the Company's estimates of the domestic production activities deduction, percentage depletion, and the possible impact of permanent differences related to state income tax calculations.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" ("FIN No. 48"), on January 1, 2007. There was no financial statement adjustment required as a result of adoption. At adoption the Company had a long-term liability for unrecognized tax benefit of $1.0 million and accumulated interest liability of $92,000. The entire amount of unrecognized tax benefit would affect the Company's effective tax rate if recognized. Interest expense associated with income tax is recorded as interest expense in the consolidated statements of operations. Penalties associated with income tax are recorded in general and administrative expense in the consolidated statements of operations.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and in various states. With few exceptions, the Company is no longer subject to U.S. federal or state income tax examinations by these tax authorities for years before and including 2003. The Internal Revenue Service completed audits for the 2000, 2002 and 2003 tax years during the quarter ended March 31, 2007. There was no change to the provision for income tax as a result of these examinations.

In the third quarter of 2007 the Company received a refund of income tax and interest of $3.1 million from a carryback of net operating losses to the 2000 tax year. An additional $980,000 is due to the Company for income tax refunds and accrued interest resulting from a carry over of minimum tax credits to the 2003 tax year. These amounts have been previously recognized by the Company.

**Note 7 - Long-term Debt**

*Revolving Credit Facility*

The Company's revolving credit facility specifies a maximum loan amount of $500 million and has a maturity date of April 7, 2010. Borrowings under the facility are secured by a pledge in favor of the lenders of collateral that includes the majority of the Company's oil and gas properties and the common stock of the material subsidiaries of the Company. The borrowing base under the credit facility as authorized by the bank group as of the date of this filing is $1.25 billion and is subject to regular semi-annual redeterminations. The borrowing base redetermination process considers the value of St. Mary's oil and gas properties and other assets, as determined by the bank syndicate. The Company has elected an aggregate commitment amount of $500 million under the credit facility. The Company must comply with certain financial and non-financial covenants. Interest and commitment fees are accrued based on the borrowing base utilization percentage table below. Euro-dollar loans accrue interest at London Interbank Offered Rate ("LIBOR") plus the applicable margin from the utilization table, and Alternative Base Rate ("ABR") loans accrue interest at Prime plus the applicable margin from the utilization table. Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations.

| Borrowing base utilization percentage | <50% | ≥50%<75% | ≥75%<90% | ≥90% |
|---|---|---|---|---|
| Euro-dollar loans | 1.000% | 1.250% | 1.500% | 1.750% |
| ABR loans | 0.000% | 0.000% | 0.250% | 0.500% |
| Commitment fee rate | 0.250% | 0.300% | 0.375% | 0.375% |

The Company had $155.0 million of Euro-dollar loans outstanding as of September 30, 2007.

*5.75% Senior Convertible Notes Due 2022*

The Company called for redemption of its 5.75% Convertible Notes on March 16, 2007. The call for redemption resulted in the note holders electing to convert the notes to common stock in accordance with the conversion provision in the original indenture. The 5.75% Convertible Note holders converted all $100.0 million of 5.75% Convertible Notes to common shares at a conversion price of $13.00 per share. The Company issued 7.7 million common shares in connection with the conversion.

*3.50%  Senior Convertible Notes Due 2027*

On April 4, 2007, the Company issued $287.5 million aggregate principal amount of 3.50% Convertible Notes.  The 3.50% Convertible Notes mature on April 1, 2027, unless earlier converted, redeemed, or purchased by the Company. The 3.50% Convertible Notes are unsecured senior obligations and rank equal in right of payment with all of the Company’s existing and any future unsecured senior debt and senior in right of payment to any future subordinated debt.

Holders may convert their notes based on a conversion rate of 18.3757 shares of the Company’s common stock per $1,000 principal amount of the 3.50% Convertible Notes (which is equal to an initial conversion price of approximately $54.42 per share), subject to adjustment, contingent upon and only under the following circumstances: (1) if the closing price of the Company's common stock reaches specified thresholds or the trading price of the notes falls below specified thresholds, (2) if the notes are called for redemption, (3) if specified distributions to holders of the Company’s common stock are made or specified corporate transactions occur, (4) if a fundamental change occurs, or (5) during the ten trading days prior to, but excluding, the maturity date.  The notes and underlying shares have been registered under a shelf registration statement.  If the Company becomes involved in a material transaction or corporate development, it may suspend trading of the 3.50% Convertible Notes under the prospectus.  In the event the suspension period exceeds 45 days within any three-month period or 90 days within any twelve-month period, the Company will be required to pay additional interest to all holders of the 3.50% Convertible Notes, not to exceed a rate per annum of 0.50 percent of the issue price of the 3.50% Convertible Notes; provided that no such additional interest shall accrue after April 4, 2009.

Upon conversion of the 3.50% Convertible Notes, holders will receive cash or common stock, or any combination thereof as elected by the Company.  At any time prior to the maturity date of the notes, the Company has the option to unilaterally and irrevocably elect to settle its obligations upon conversion of the notes in cash and, if applicable, shares of common stock.  If the Company makes this election, then, for each $1,000 principal amount of notes converted, the Company will pay the following to holders in lieu of shares of common stock: (1) an amount in cash equal to the lesser of (i) $1,000 or (ii) the conversion value determined in the manner set forth in the indenture for the 3.50% Convertible Notes, and (2) if the conversion value exceeds $1,000, the Company will also deliver, at its election, cash or common stock or a combination of cash and common stock with respect to the remaining value deliverable upon conversion.  Currently, it is the Company’s intention to net share settle the 3.50% Convertible Notes.  However, the Company has not made this a formal legal irrevocable election and thereby reserves the right to settle the 3.50% Convertible Notes in any manner allowed under the offering memorandum as business conditions warrant.

If a holder elects to convert its notes in connection with certain events that constitute a change of control before April 1, 2012, the Company will pay, to the extent described in the related indenture, a make-whole premium by increasing the conversion rate applicable to the 3.50% Convertible Notes.  In addition, the Company will pay contingent interest in cash, commencing with any six-month period beginning on or after April 1, 2012, if the average trading price of a note for the five trading days ending on the third trading day immediately preceding the first day of the relevant six-month period equals 120 percent or more of the principal amount of the 3.50% Convertible Notes.

On or after April 6, 2012, the Company may redeem for cash all or a portion of the 3.50% Convertible Notes at a redemption price equal to 100 percent of the principal amount of the notes to be redeemed plus accrued and unpaid interest, if any, up to but excluding, the applicable redemption date.  Holders of the 3.50% Convertible Notes may require the Company to purchase all or a portion of their notes on each of April 1, 2012, April 1, 2017, and April 1, 2022, at a purchase price equal to 100 percent of the principal amount of the notes to be repurchased plus accrued and unpaid interest, if any, up to but excluding the applicable purchase date.  On April 1, 2012, the Company may pay the

purchase price in cash, in shares of common stock, or in any combination of cash and common stock. On April 1, 2017 and April 1, 2022, the Company must pay the purchase price in cash.

In August 2007 the FASB proposed FASB Staff Position APB 14-a, “Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (including Partial Cash Settlement)”, (“FSP APB 14-a”). FSP APB 14-a proposes that the accounting treatment for certain convertible debt instruments that may be settled in cash, shares of common stock, or any portion thereof at the election of the issuing company be accounted for utilizing a bifurcation model under which the value of the debt instrument would be determined without regard to the conversion feature. The difference between this calculated value and the convertible debt instrument issue price would be allocated to the option and recorded as equity rather than debt. Pending enactment, the changes are proposed to become effective for years beginning after December 15, 2007. FSP APB 14-a does not contain a grandfather provision, thus the Company would be required to account for its existing convertible debt instruments using the prescribed bifurcation method under the framework described by the FASB.

*Weighted-average Interest Rate Paid and Capitalized Interest Costs*

The weighted-average interest rates paid for the third quarters of 2007 and 2006 were 5.1 percent and 7.5 percent, respectively, including commitment fees paid on the unused portion of the credit facility aggregate commitment, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the 5.75% Convertible Notes, and the effects of interest rate swaps. The weighted-average interest rates paid for the nine-month periods ended September 30, 2007, and 2006, were 5.9 percent and 7.9 percent, respectively. Capitalized interest costs for the Company for the three-month periods ended September 30, 2007, and 2006 were $1.2 million and $896,000, respectively, and capitalized interest costs for the nine-month periods ended September 30, 2007, and 2006, were $3.8 million and $2.3 million, respectively.

**Note 8 – Derivative Financial Instruments**

*Oil and Gas Commodity Hedges*

To mitigate a portion of the potential exposure to adverse market changes in oil and natural gas prices, the Company has entered into various derivative contracts. The Company’s derivative contracts in place include swap and collar arrangements for the sale of oil, natural gas, and natural gas liquids. Please refer to the tables under *Summary of Oil and Gas Production Hedges in Place* in Part I, Item 2 of this quarterly report for details regarding the Company’s hedged volumes and associated prices. As of the date of this filing, the Company has hedge contracts in place through 2011 for approximately 13 million Bbls of anticipated crude oil production, 79 million MMBtu of anticipated natural gas production, and 1 million Bbls of anticipated natural gas liquids production.

The Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"), and related pronouncements. The Company formally documents all relationships between the derivative instruments and the hedged production, as well as the Company’s risk management objective and strategy for the particular derivative contracts. This process includes linking all derivatives that are designated as cash flow hedges to the specific forecasted sale of oil or natural gas at its physical location. The Company also formally assesses (both at the derivative’s inception and on an ongoing basis) whether the derivatives being utilized have been highly effective at offsetting changes in the cash flows of hedged production and whether those derivatives may be expected to remain highly effective in future periods. If it is determined that a derivative has ceased to be highly effective as a hedge, the Company will discontinue hedge accounting prospectively for that derivative instrument. If hedge accounting is discontinued and the derivative remains outstanding, the Company

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will recognize all subsequent changes in its fair value in the consolidated statements of operations for the period in which the change occurs. As of September 30, 2007, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. Two natural gas liquids derivative contracts entered into during the third quarter of 2007 did not qualify for cash flow accounting due to a lack of underlying production. These hedges were entered into as a result of the Gold River acquisition and upon closing of the acquisition in the fourth quarter of 2007 were designated against the acquired production. The Company recorded $1.5 million of derivative loss in the financial statements related to these unqualified hedges for the three- and nine-month periods ended September 30, 2007. The Company anticipates that all forecasted transactions will occur by the end of their originally specified periods. All contracts are entered into for other than trading purposes.

The fair value of derivative instruments is included in the consolidated balance sheets as an asset or liability. The estimated fair value of oil, natural gas, and natural gas liquids derivative contracts was a net liability of $84.9 million at September 30, 2007.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section in the consolidated statements of operations. Changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in unrealized derivative gain or loss in the consolidated statements of operations.

The Company seeks to minimize ineffectiveness by entering into oil derivative contracts indexed to NYMEX and natural gas contracts indexed to regional index prices associated with pipelines in proximity to the Company's areas of production. As the Company's derivative contracts contain the same index as the Company's sale contracts, this results in hedges that are highly correlated with the underlying hedged item.

Derivative gain from ineffectiveness related to oil, natural gas, and natural gas liquids derivative contracts qualifying for hedge accounting for the three-month period ended September 30, 2007 was $4.3 million. A net loss of $433,000 was recorded for the same period in 2006. Amounts for the nine-month periods ended September 30, 2007, and 2006, were a net loss of $900,000 and $6.2 million, respectively.

As of September 30, 2007, the estimated amount of unrealized derivative loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to realized oil and gas hedge loss in the next twelve months was $5.9 million.

The following table summarizes derivative instrument gain (loss) activity:

| | For the Three Months Ended September 30, 2007 | 2006 | For the Nine Months Ended September 30, 2007 | 2006 |
|---|---|---|---|---|
| | (In thousands) | | (In thousands) | |
| Derivative contract settlements realized in oil and gas hedge gain | $ 10,173 | $ 4,828 | $ 36,160 | $ 14,808 |
| Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss) | 4,336 | (433) | (889) | (6,187) |
| Non-qualified derivative contracts included in derivative gain (loss) | (1,456) | 366 | (1,335) | 859 |
| Interest rate derivative contract settlements included in interest expense | - | (275) | (283) | (550) |
| Total gain | $ 13,053 | $ 4,486 | $ 33,653 | $ 8,930 |

*Interest Rate Derivative Contracts*

Effective September 13, 2007, the Company entered into a one year floating-to-fixed interest rate derivative contract for a notional amount of $75 million. Under the agreement, the Company will pay a fixed rate of 4.90 percent and will be paid a variable rate of the one-month LIBOR rate. The fair value of the interest rate derivative was a liability of $166,000 as of September 30, 2007. This derivative qualifies for cash flow hedge accounting treatment under SFAS No. 133 and related pronouncements. Consequently, the Company did not record a net derivative gain or loss in the consolidated statements of operations for the three-month period ended September 30, 2007, related to this interest rate derivative contract.

*Convertible Note Derivative Instrument*

The contingent interest provision of the 5.75% Convertible Notes was considered an embedded equity-related derivative that was not clearly and closely related to the fair value of an equity interest and therefore was separately accounted for as a derivative instrument. There was no derivative gain or loss recorded in the consolidated statements of operations for the three-month and nine-month periods ended September 30, 2007, and there was a net gain of $238,000 recorded for the three-month period ended September 30, 2006, and a net gain of $468,000 recorded for the nine-month period ended September 30, 2006, from mark-to-market adjustments for this derivative. The contingent interest provision of the 3.50% Convertible Notes is also a derivative instrument. However, the value of this derivative was determined to be de minimis at the inception of the instrument.

**Note 9 – Pension Benefits**

The Company has a non-contributory pension plan covering substantially all employees who meet age and service requirements (the “Qualified Pension Plan”). The Company also has a supplemental non-contributory pension plan covering certain management employees (the “Non-qualified Pension Plan”).

*Components of Net Periodic Benefit Cost for Both Plans*

The following table presents the components of the net periodic cost for both the Qualified Pension Plan and the Non-qualified Pension Plan:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In thousands) | | (In thousands) | |
| Service cost | $ 478 | $ 422 | $ 1,433 | $ 1,264 |
| Interest cost | 198 | 163 | 595 | 489 |
| Expected return on plan assets | (135) | (107) | (405) | (297) |
| Amortization of net actuarial loss | 55 | 74 | 164 | 222 |
| Net periodic benefit cost | $ 596 | $ 552 | $ 1,787 | $ 1,678 |

Prior service costs are amortized on a straight-line basis over the average remaining service period of active participants. Gains and losses in excess of ten percent of the greater of the benefit obligation and the market-related value of assets are amortized over the average remaining service period of active participants.

*Contributions*

The Company contributed $1.6 million to the Qualified Pension Plan during the second quarter of 2007. No further contributions to the Qualified Pension Plan are planned for the remainder of 2007.

**Note 10 - Asset Retirement Obligations**

The Company recognizes an estimated liability for future costs associated with the abandonment of its oil and gas properties. A liability for the fair value of an asset retirement obligation and a corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is completed or acquired. The increase in carrying value is included in proved oil and gas properties in the consolidated balance sheets. The Company depletes the amount added to proved oil and gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and gas properties. Cash paid to settle asset retirement obligations is included in the operating section of the Company’s consolidated statements of cash flows.

The Company’s estimated asset retirement obligation liability is based on historical experience in abandoning wells, estimated economic lives, estimates as to the cost to abandon the wells in the future, and federal and state regulatory requirements. The liability is discounted using a credit-adjusted risk-free rate estimated at the time the liability is incurred or revised. The credit-adjusted risk-free rates used to discount the Company’s abandonment liabilities range from 6.50 percent to 7.25 percent. Revisions to the liability could occur due to changes in estimated abandonment costs or well economic lives, or if federal or state regulators enact new requirements regarding the abandonment of wells.

A reconciliation of the Company's asset retirement obligation liability is as follows:

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| | (In thousands) | | (In thousands) | |
| Beginning asset retirement obligation | $ 90,554 | $ 69,011 | $ 77,242 | $ 66,078 |
| Liabilities incurred | 2,702 | 1,106 | 7,443 | 2,864 |
| Liabilities settled | (3,380) | (131) | (4,678) | (1,293) |
| Accretion expense | 1,465 | 1,222 | 4,215 | 3,559 |
| Revision to estimated cash flow | 651 | - | 7,770 | - |
| Ending asset retirement obligation | $ 91,992 | $ 71,208 | $ 91,992 | $ 71,208 |

Accounts payable and accrued expenses as of September 30, 2007, contain $6.9 million related to the Company's asset retirement obligation. The amount relates to the estimated plugging and abandonment costs associated with one offshore platform that was destroyed during Hurricane Rita. Plugging and abandonment of the platform is expected to be completed by the end of 2007. Accounts payable and accrued expenses did not contain an amount related to the Company's asset retirement obligation as of December 31, 2006.

**Note 11 – Repurchase of Common Stock**

*Stock Repurchase Program*

During the third quarter of 2007 St. Mary repurchased 790,816 shares of its outstanding common stock in the open market at a weighted-average price of $32.76 per share, including commissions, for a total of $25.9 million. As of the date of this filing, the Company has Board authorization to repurchase up to 5,209,184 shares of common stock. The shares may be repurchased from time to time in open market transactions or in privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under the revolving credit facility.

During the second quarter of 2006 St. Mary repurchased 3,319,300 shares of its common stock at a weighted-average price of $37.09 per share including commissions.

**Note 12 – Insurance Settlement**

In April of 2007 the Company reached a global insurance settlement for reimbursement of damages sustained during Hurricane Rita. St. Mary's net amount of the final settlement is approximately $33 million. As a result of this settlement, the Company recorded a gain of $6.3 million in other revenue in the accompanying financial statements for the nine-month period ended September 30, 2007. The gain calculation takes into consideration approximately $10.0 million of future costs associated with the plugging and abandonment of one offshore platform. Additionally, the Company has accrued for approximately $708,000 of expected hurricane related damage repair costs related to its outside-operated properties. The Company continues to closely monitor the activities associated with these properties. Any significant variation between actual and estimated plugging and abandonment and outside-operated damage repair costs will impact the final determination of the gain associated with the insurance settlement. The Company expects adjustments to the gain to be completed by the fourth quarter of 2007.

**Note 13 – Subsequent Events**

*Gold River Acquisition*

On October 4, 2007, the Company completed the purchase of certain oil and gas properties in the Olmos producing formation located primarily in Webb and Dimmit counties, Texas in the Gold River Field. These assets were purchased from Rockford Energy Partners II, LLC. Total cash paid was $151.0 million, for the purchase price net of customary closing adjustments to account for activity between the effective date and the closing date. The acquisition was funded with cash on hand and borrowings under the Company's existing revolving credit facility. This property acquisition is adjacent to the recently acquired Catarina Field assets discussed in Note 3 – Acquisitions, Divestitures, and Assets Held for Sale. The Company has hedged the first three years of natural gas production and the first two years of associated natural gas liquids production.

*Variable Interest Entity*

Prior to closing on the Gold River acquisition, the Company assigned all of its rights and duties under the purchase and sale agreement to NBF Reverse Exchange, LLC, an indirect wholly-owned subsidiary of Comerica Incorporated, which further assigned all of its rights and duties under the purchase and sale agreement to St. Mary Land & Exploration Acquisition Company, LLC ("SMLEA, LLC"), a company unaffiliated with St. Mary. The acquisition of properties in the Gold River Field has been structured to qualify as the first step of a reverse like-kind exchange under Section 1031 of the Internal Revenue Code of 1986, as amended, and I.R.S. Revenue Procedure 2000-37. The Gold River assets were acquired by NBF Reverse Exchange, LLC as an exchange accommodation titleholder. SMLEA, LLC will hold the assets pursuant to a qualified exchange accommodation agreement until the second step of the like-kind exchange is completed. As of the date of closing on October 4, 2007, the assets held by SMLEA, LLC, are being leased by St. Mary under a triple net lease whereby St. Mary enjoys the benefits and risks of all revenues and costs attributed to the properties. The Gold River assets are managed by St. Mary under the terms of a management agreement with SMLEA, LLC. The second step of the like-kind exchange is expected to be completed in conjunction with the divestiture of certain non-core oil and gas properties discussed in Note 3 – Acquisitions, Divestitures, and Assets Held for Sale.

In connection with the reverse like-kind exchange described above, St. Mary loaned an amount equal to the purchase price of the assets to SMLEA, LLC. Based on the provisions of FASB Interpretation No. 46(R), "*Consolidation of Variable Interest Entities*", the Company determined that SMLEA, LLC is a variable interest entity for which St. Mary is the primary beneficiary. Accordingly, SMLEA, LLC will be consolidated into St. Mary beginning on October 4, 2007. As of October 4, 2007, SMLEA, LLC had total assets of approximately $151 million. As a result of the consolidation, St. Mary will recognize all oil and gas reserves and production as well as all revenues and expenses attributed to the Gold River acquisition beginning on October 4, 2007.

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

This discussion contains forward-looking statements. Please refer to "Cautionary Information about Forward-Looking Statements" at the end of this item for an explanation of these types of statements.

### Overview of the Company

*General Overview*

We are an independent energy company focused on the exploration, exploitation, development, acquisition, and production of natural gas and crude oil in the United States. We earn greater than 90 percent of our revenues and generate our cash flows from operations primarily from the sale of produced natural gas, natural gas liquids, and crude oil. Our oil and gas reserves and operations are concentrated primarily in various Rocky Mountain basins, including the Williston, Big Horn, Wind River, Powder River, and Greater Green River basins; the Mid-Continent Anadarko and Arkoma basins; the Permian Basin; the tight sandstone and carbonate formations of East Texas and North Louisiana; South Texas assets targeting the Olmos formation; and the onshore Gulf Coast and offshore Gulf of Mexico.

Our primary objective is growing net asset value per share. Over the long term we believe that growing net asset value per share leads to superior stock price performance. A focus on net asset value per share provides us the flexibility to pursue a variety of projects that we believe will create value and requires us to be disciplined in our investment decisions. We believe that our regional diversity and the balance between oil and natural gas in our proved reserves are advantages that we can leverage to build value for our stockholders.

*Oil and Gas Production and Operating Margins*

Our production for the third quarter of 2007 was 27.5 BCFE. This is the seventh consecutive quarter of increasing production. Production increases throughout 2007 have been the result of our ongoing drilling operations, as well as the acquisition and subsequent development of oil and gas assets in the Permian region that were purchased in December 2006 and the Catarina Field acquisition that closed on June 1, 2007. Production for the third quarter was higher than we had projected earlier in the year which we believe is attributable primarily to overall well performance. Growth of production from quarter to quarter is impacted by the timing of drilling operations, completions, workovers, and other operational issues, as well as the overall production decline rate of our existing asset base. We believe that an important metric for measuring success of oil and gas production companies is the ability to grow reserves on an economic basis, which then provides a base for growth in production that will positively affect our net asset value.

Our operating margins, net of general and administrative costs, remain very strong because approximately 40 percent of our 2007 production to date is crude oil. Strong crude oil prices and solid realizations from our hedging program, specifically on natural gas, have contributed to a net equivalent operating margin of $6.21 per MCFE. This represents a four percent increase from the same period a year ago.

*Oil and Gas Prices*

Our results of operations and financial condition are significantly affected by oil and natural gas commodity prices, which can fluctuate dramatically. We sell the majority of our natural gas under contracts that use first of the month index pricing, which means gas produced in that month is sold at the first of the month price regardless of the spot price on the day the gas is produced. Our crude oil is sold using contracts that pay us the average of the NYMEX West Texas Intermediate (WTI) daily settlement or the average of the posted prices for the period in which the crude oil is produced, adjusted for market quality, transportation, and location differentials.

The three-month average bid week price for natural gas at Henry Hub decreased 19 percent to $6.13 per Mcf between the second quarter and third quarter of 2007. This was six percent lower than the same period in 2006. The high level of natural gas in storage resulting from a mild summer was the primary driver of lower prices. While high natural gas inventories led to a general decline in prices across the country, the Rocky Mountain region was affected more than most. The increased basis differential between Henry Hub and various Rocky Mountain natural gas hubs that existed for most of the year continued throughout the third quarter of 2007. A significant amount of our gas production in the Rocky Mountains is associated with the production of oil. For us, the strong price for oil economically justifies the continued production of gas despite currently weaker gas prices. Our exposure to Colorado Interstate Gas pricing is relatively small, representing approximately seven percent of our total equivalent production. A major pipeline project, known as Rockies Express, impacting the Rocky Mountain region, is expected to come online in early 2008. The differentials implied by the futures curves between Rocky Mountain hubs and Henry Hub indicate that the pressure on prices in the Rocky Mountains should moderate when Rockies Express is placed into service. Overall, the futures market for natural gas is stronger than current pricing, with NYMEX first, second, and third year strips trading at $8.52, $8.70, and $8.41, respectively, on an MMBtu basis as of the end of the third quarter of 2007. Subsequent to September 30, 2007, natural gas futures prices remain relatively stable compared to those seen at the end of the third quarter of 2007. Additionally, the amount of natural gas liquids that can be extracted from our gas production has increased in recent quarters primarily as a result of the acquisition of properties in the Permian Basin in late 2006. As a result, the actual difference between the NYMEX natural gas price and our pre-hedge realized price was smaller than we had estimated because of the contribution from natural gas liquids.

The average daily NYMEX price for WTI crude for the third quarter of 2007 was $75.38 per barrel, which represents a 16 percent increase from the second quarter of 2007.

Crude oil prices increased steadily over the second half of the third quarter of 2007 in response to tightening of supplies and continued geopolitical unrest. In addition, financial markets responded to concerns regarding crude oil inventories in the United States as well as the declining value of the U.S. dollar. Approximately 66 percent of our crude oil production comes from our properties in the Rocky Mountain region, where the third quarter average differential was the lowest we have experienced in 2007. In mid-October, the prompt month NYMEX contract traded at over $90 per barrel and first, second, and third year NYMEX strips recently closed at $89.56, $83.49, and $81.25, respectively, on a per barrel basis.

While changes in quoted NYMEX oil and Henry Hub natural gas prices are generally used as a basis for comparison within our industry, the price we receive for oil and natural gas is affected by quality, energy content, location, and transportation differentials for these products. We refer to this price as our realized price, which excludes the effects of hedging. Our realized price is further impacted by the result of our hedging contracts that have settled in the respective periods, which is referred to as our net realized price. Our natural gas price realizations for the three months ended September 30, 2007, were improved by $17.6 million of realized hedging gains while our oil price realization was negatively impacted by $7.4 million of realized hedging losses. For the nine months ended September 30, 2007, our natural gas price realizations were improved by $45.5 million of realized hedging gains and our oil price realization was negatively impacted by $9.3 million of realized hedging losses. On a percentage basis, we have hedged more forecasted crude oil production than forecasted natural gas production. Furthermore, a significant portion of our anticipated crude oil production is hedged using swap prices that are below the current NYMEX strip prices, moderating the benefit that could be gained from the increase in oil prices.

| | For the Three Months Ended September 30, 2007 |
|---|---|
| Crude Oil (per Bbl) : | |
| NYMEX price | $ 75.38 |
| Net realized price | $ 71.68 |
| Net realized price, including the effects of hedging | $ 67.56 |
| | |
| Natural Gas (per Mcf) : | |
| NYMEX price | $ 6.13 |
| Net realized price | $ 5.98 |
| Net realized price, including the effects of hedging | $ 7.03 |

*Hedging Activities*

We have an active hedging program, which is largely utilized for acquisitions. We hedge the first two to five years of an acquisition's risked production. We occasionally enter into derivative transactions to hedge a portion of our existing forecasted production. Taking into account all oil and gas production hedge contracts in place through the date of this filing, we have hedged anticipated production of approximately 13 million Bbls of oil, 79 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids through the year 2011. We believe we have established an economic base for our future operations, and the floors and ceilings on our collars minimize our exposure to price declines while also allowing us to participate in a higher oil and natural gas price environment. Please see Note 8 – Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges, and see the caption, *Summary of Oil and Gas Production Hedges in Place,* later in this section.

*Drilling and Completion Cost Environment*

After several years of cost escalation, we have begun to see cost reductions for some services associated with drilling operations. In general, day rates for land-based drilling rigs are holding steady and in some cases are decreasing as drillers face an increasing supply of drilling rigs entering the market. Additionally, we believe there is potential to further reduce costs by working with more efficient service providers. Prices for completion services continue to be firm, although new capacity is being added by incumbent providers as well as new entrants to the drilling service sector. The cost environment remains highly dynamic and varies greatly from region to region. Historically, cost changes have lagged commodity prices, both on upward and downward price trends. In making our investment decisions, we evaluate current economics on an individual investment basis prior to proceeding. We have a formal process for establishing a drilling budget and our prospect inventory and strong balance sheet give us the flexibility to adjust this budget as additional opportunities arise or as the economics of our planned activities change. As of the date of this filing, our drilling budget for 2007 is unchanged since our last estimate at $727 million for drilling, plus approximately $190 million of acquisitions, as discussed below.

As a result of the growth in our drilling inventory, we have initiated a review of our purchasing practices with the intention of consolidating our purchasing efforts to realize savings through volume discounts offered by vendors as well as to secure a supply of critical materials.  We believe that this initiative will have a positive impact on our cost structure over the next several years.

*Net Profits Plan*

Payments made for distributions from the Net Profits Plan in the amounts of $8.2 million and $22.0 million have been expensed as compensation costs for the three-month and nine-month periods ended September 30, 2007, respectively.  These payments are slightly lower than originally budgeted due to the effects of increased oil and gas production expense and additional capital expenditures, which decreased the current impact of and delayed the timing of payout for the 2004 pool.  Actual cash payments will be inherently different from the estimated liability amount.  Additional discussion is included in the analysis in the *Comparison of Financial Results and Trends* sections below.  We estimate that we will pay approximately $32 million of cash payments through the end of 2007, but this amount does not include any potential cash payments made as a result of our planned divestiture of non-core oil and gas properties.  It is not possible to predict this liability with certainty due to the impact of commodity prices, operating costs, and actual produced volumes.

With respect to the accounting estimate of the liability associated with future estimated payments from our Net Profits Plan, we have recorded $6.9 million of net expense for the nine-month period ended September 30, 2007.  We note the liability has increased $3.1 million from June 30, 2007.  This increase is due to an increase in estimated future payments predominately caused by an increase in oil prices.

The calculation of the estimated liability associated with the Net Profits Plan requires management to prepare an estimate of future amounts payable from the plan.  On a monthly basis, we calculate estimates of the payments to be made for each individual Net Profits Plan pool.  The underlying principal factors for our estimates are forecasted oil and gas production from the properties that comprise each individual pool, price assumptions, cost assumptions, and the discount rate.  In most cases, the cash flow streams used in these calculations will span more than 20 years.  We generally use a 15 percent discount rate to calculate the present value of these future payments, and the resulting amount is recorded as a liability.  Commodity prices impact the calculated cash flows during periods both before and after payout and can dramatically affect the timing of the estimated date of payout of the individual pools.  Our commodity price assumptions are currently determined from an average of actual prices realized over the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months for a total of 36 months of data.  This average is supplemented by including the effect of commodity price realizations and anticipated hedge prices for the percentage of forecasted hedged production in the relevant period.  The calculation of the estimated liability for the Net Profits Plan is highly sensitive to our price estimates and discount rate assumptions.  For example, if we changed the commodity prices in our calculation by five percent, the liability recorded on the balance sheet at September 30, 2007, would differ by approximately $15 million.  A one percentage point change in the discount rate would result in a change to the liability of approximately $10 million.  We frequently re-evaluate the assumptions used in our calculations and consider the possible impacts stemming from the current market environment including current and future oil and gas prices, discount rates, and overall market conditions.

*Third Quarter 2007 Highlights*

In August 2007, we announced that Robert L. Nance, 71, the long-serving President and CEO of our wholly-owned subsidiary, Nance Petroleum Corporation, and regional manager of our Rocky Mountain region, intends to retire in the first quarter of 2008.  We also announced that Mark D. Mueller had joined us and will succeed Mr. Nance as regional manager of the Rocky Mountain region effective November 5, 2007.  Mr. Nance will continue to serve as an executive advisor to the CEO and President of St. Mary through the date of his retirement.

Throughout August 2007 we repurchased a total of 790,816 shares of outstanding common stock in the open market. The shares were repurchased at a weighted-average cost of $32.76 per share, including commissions, using cash on hand and borrowings under our existing revolving credit facility. We repurchased the shares under our existing Board authorized stock repurchase program. As of the date of this filing, we are authorized to repurchase 5,209,184 additional shares under this program. Consistent with our view of treating large share repurchases as acquisitions, we have hedged production volumes equal to the amount of reserves represented by the repurchased shares in proportion to the total number of shares outstanding. Our management continues to evaluate the opportunities to repurchase common stock as a part of our business plan.

Our third quarter 2007 net income was $57.7 million or $0.89 per diluted share compared to 2006 results of $55.9 million or $0.88 per diluted share. Production for the third quarter was 27.5 BCFE. The production increase represents a 19 percent increase from the same period a year ago and a six percent increase from the previous quarter. Per MCFE lease operating expense and transportation expense increased $0.06 to $1.46 as compared to $1.40 from the same period of 2006. Production taxes remained flat at $0.54 per MCFE, and depreciation, depletion, and amortization (DD&A), including ARO accretion expense, increased $0.43 to $2.15 per MCFE. Although our production volumes have increased, the net income increase was tempered by increased costs, particularly in depreciation, depletion, and amortization. The increase in general and administrative expenses is driven by our growing employee base. It is also affected by the increase in Net Profits Plan payments, as well as a higher bonus accrual compared to the same period in 2006. Exploration expense for the third quarter of 2007 was $15.3 million, which was $5.5 million higher than the $9.8 million incurred during the third quarter of 2006 due to the overall increase in the level of activity and the increase in payments under the Net Profits Plan during 2007. We discuss these financial results and trends in more detail below.

In September 2007, we engaged a third party marketing firm to coordinate a property divestiture of certain non-core oil and gas properties. The divestiture package represents non-strategic assets that are located primarily in the Rocky Mountain and Mid-Continent regions. Bids are expected to be received by mid-November 2007, and the transaction is expected to close before the end of the year. We plan to use a like-kind exchange structure for a portion of the sales proceeds, which we believe will add additional value.

The table below provides information regarding selected production and financial information for the quarter ended September 30, 2007, and the immediately preceding three quarters. Additional per MCFE detail is contained later in this section.

| | For the Three Months Ended | | | |
|---|---|---|---|---|
| | September 30, 2007 | June 30, 2007 | March 31, 2007 | December 31, 2006 |
| | (In millions, except production sales data) | | | |
| Production (MCFE) | 27.5 | 26.0 | 25.5 | 25.1 |
| Oil and gas production revenues before the effects of hedging | $ 228.5 | $ 216.2 | $ 193.7 | $ 180.6 |
| Lease operating expense | $ 36.9 | $ 31.6 | $ 34.1 | $ 31.2 |
| Transportation costs | $ 3.2 | $ 4.2 | $ 4.4 | $ 3.0 |
| Production taxes | $ 14.9 | $ 14.5 | $ 13.7 | $ 12.9 |
| General and administrative expense | $ 13.1 | $ 13.7 | $ 11.1 | $ 7.9 |
| Net income | $ 57.7 | $ 59.2 | $ 40.0 | $ 43.5 |
| Percentage change from previous quarter: | | | | |
| Production (MCFE) | 6% | 2% | 2% | 8% |
| Oil and gas production revenues before the effects of hedging | 6% | 12% | 7% | (4)% |
| Lease operating expense | 17% | (7)% | 9% | 4% |
| Transportation costs | (24)% | (5)% | 47% | 25% |
| Production taxes | 3% | 6% | 6% | 3% |
| General and administrative expense | (4)% | 23% | 41% | (19)% |
| Net income | (3)% | 48% | (8)% | (22)% |

*First Nine Months 2007 Financial Highlights*

In the first nine months of 2007 our net income was $156.8 million or $2.43 per diluted share compared to the first nine months of 2006 income of $146.5 million or $2.25 per diluted share. Production for the first nine months was 79.0 BCFE. This represents a 17 percent increase from the same period a year ago. Per MCFE lease operating expense increased $0.05 to $1.30 as compared to a year ago. This increase over last year's comparable period is due to an increase in oil and gas production expense. While costs associated with drilling and completing wells are staying flat or declining, costs related to the ongoing operation of oil and gas properties continue to experience upward pressure. As a company with a significant oil component to our production mix, our property base inherently requires more labor than operations that are dominated by natural gas production. Labor costs continue to be a significant driver of our lease operating expense. In addition to the higher costs we are incurring on our base activity, we also have been actively repairing properties in order to restore or increase production in the Gulf Coast and Rockies. Per MCFE transportation costs increased $0.03 to $0.15 as compared to a year ago. The increase is due to a change in the sales measurement point for wells located in the Rocky Mountain region as well as newly drilled wells with higher transportation costs. Production taxes increased $0.01 to $0.55 per MCFE, and DD&A, including ARO accretion expense, increased $0.43 to $2.06 per MCFE. We discuss these financial results and trends in more detail below.

We called our 5.75% Convertible Notes for redemption in March 2007. The note holders elected conversion of the notes into shares of common stock. As a result, we reclassified the $100.0 million of

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debt associated with the issuance to equity and issued 7.7 million shares of common stock. The combination of this conversion, the issuance of $287.5 million of 3.50% Convertible Notes, net income earned for the nine-month period ended September 30, 2007, the repurchase of $25.9 million of common stock in August 2007, and the change in accumulated other comprehensive income primarily associated with changes in derivative valuations, has resulted in our debt to book capitalization ratio decreasing from 37 percent at December 31, 2006, to 32 percent at September 30, 2007.

*Events Subsequent to September 30, 2007*

On October 4, 2007, we closed the previously announced $153 million Gold River acquisition of oil and gas properties located primarily in Webb and Dimmit counties, Texas from Rockford Energy Partners II, LLC. The properties are predominantly natural gas and associated liquids which target the Olmos formation. This acquisition is adjacent to our properties at Catarina Field, which we acquired in June 2007. Total cash paid for the acquisition was $151 million, for the purchase price net of customary closing adjustments, using cash on hand and borrowings under our existing revolving credit facility. We have hedged the first three years of gas production and the first two years of associated liquids. We have estimated proved reserves associated with this acquisition of approximately 95 BCFE.

*Outlook for the Remainder of 2007*

The execution of our drilling program, a focus on reducing operating costs, and the divestiture of our assets held for sale will be the principal areas of focus over the remainder of the year. We expect to have access to the rigs and services required to carry out our drilling program. Finding and retaining qualified employees and contractors continues to be one of the biggest challenges to our industry. The current commodity price and cost environment supports the remainder of our 2007 capital program. We believe that we have access to the requisite personnel, equipment, and services required to execute on our program. The highlights of the remaining 2007 capital program include:

- *ArkLaTex*– Activity in the ArkLaTex for 2007 is focused on an operated horizontal carbonate program in the James Lime trend and two outside-operated programs. We are planning to operate one to two rigs in our horizontal carbonate program over the remainder of 2007. We plan to continue to drill in areas where we have announced successful tests outside the historic development area this year. The two successful outside-operated plays are the Elm Grove and Terryville fields, both of which target the Cotton Valley formation. We are pleased with the pace of development of our operating partners at Elm Grove, who are currently operating three rigs in acreage where we have an interest. Increased density drilling on 20 acre spacing and horizontal drilling are potential developments we continue to discuss with our partners. At Terryville Field, two outside-operated rigs are currently operating on our acreage. Recent wells drilled in the area by our operating partner have met our expectations.

- *Gulf Coast* – In this region, activity for the remainder of 2007 will be centered on integrating our new acquisitions at Catarina and Gold River Field, which target natural gas in the shallow Olmos formation in South Texas. We currently have one operated drilling rig running in Catarina Field and expect to operate one to two drilling rigs in Gold River Field. During the third quarter, we had two exploration discoveries in our direct hydrocarbon indicator program. Both wells targeted the mid-Miocene era sands and are expected to be placed on production near the end of 2007. We also anticipate continuing to complete and develop a number of previously announced exploration wells.

- *Mid-Continent*– Our 2007 plans in the Mid-Continent are principally centered on the Arkoma program in eastern Oklahoma and the Anadarko Basin in western Oklahoma.  Two operated rigs are currently working in the Arkoma program, where we are primarily targeting the Woodford shale formation with horizontal wells.  We are encouraged by the results of our most recent wells, which we believe have improved our understanding of the reservoir system and have helped validate the drilling and completion designs that we plan to use going forward.  We are in the process of acquiring additional 3D seismic, after which we will have approximately 75 percent of our acreage covered by 3D seismic.  In the Anadarko Basin, we are operating two rigs currently.  Plans for the remainder of the year in the Anadarko Basin are focused on drilling wells targeting the Granite Wash formation and high-grading our inventory of Atoka locations.

- *Permian Basin* – Our Permian Basin activity in 2007 will be significantly higher as a result of the development of two programs targeting the Permian age Spraberry interval, now widely referred to in the industry as the Wolfberry play.  These programs are the operated Sweetie Peck assets and an outside-operated program at Halff East.  Well performance at Sweetie Peck continues to be in line with expectations set at the time of the acquisition in late 2006.  Due to the disappointing operational performance of two rigs in this program, we have reduced our current rig count in this program from five to three.  Activity at Sweetie Peck ran ahead of schedule for most of the year, and as a result we expect it to meet its production budget for the year.

At Halff East, we now plan to drill more than twice the original 15 wells that were planned at the beginning of the year.  The increase in this program reflects results that have exceeded our initial expectations.  There are currently two outside-operated rigs running in the program.

Between Sweetie Peck and Halff East, we now expect to drill or participate in the drilling of 80 wells targeting the Wolfberry, up from an original budget of 69 wells.

- *Rockies - Conventional* – Our 2007 operated property plan for the conventional Rockies program involves continuing the horizontal re-entry program in the Mississippian formations of the Williston Basin, the exploitation of Bakken infill locations in Montana, and drilling Red River projects.  We plan to operate two to three rigs in this region for the remainder of the year.  Outside-operated activities include wells targeting the Bakken, Madison, and Mission Canyon formations in the Williston Basin.  Other outside-operated activity includes wells targeting the Almond formation in the eastern Green River Basin; however, due to significant natural gas price decreases in this region, a number of the projects we planned to pursue will be delayed until 2008.  Oil projects in this region continue to have solid economics given high oil prices.

- *Rockies - Hanging Woman Basin Coalbed Methane* – At the end of September 2007, there were 391 wells producing 11.1 MMcf per day gross and 6.8 MMcf per day net.  Due to pressure on natural gas prices in the Rocky Mountains, we had briefly reduced gas production at Hanging Woman Basin while ensuring transportation obligations were met and necessary dewatering efforts continued.  Subsequent to quarter end, we secured better pricing and have resumed full production at Hanging Woman Basin.  We are currently operating six rigs in the Hanging Woman Basin program.  Our efforts for the remainder of the year center on expanding the development on the eastern half of this project, completing wells on 80 acre spacing in the shallow coals and drilling additional test wells in the deeper Roberts and Kendick coals.  Our expectations are that incremental production from the Hanging Woman Basin program will be approximately 3 BCFE for 2007 although the number of wells drilled will be less than previously anticipated mainly due to drilling delays earlier this year caused by record rainfall in the Powder River Basin.  We are carefully evaluating the future drilling program for the Hanging Woman Basin project to determine the most appropriate and efficient plan of development.

Our planned drilling program described above is dynamic, and there are a number of factors that could impact our decisions to invest capital in one or all of these regions.  Commodity prices, well costs, and program performance are a few factors that individually or in combination could change the scale or relative allocation of our drilling and acquisition budgets.

We continue to evaluate acquisitions, both in our regional offices and at our corporate headquarters.  We anticipate capital spending for acquisitions of approximately $190 million in 2007.  We have a strong track record of executing economic acquisitions.  We have grown our inventory of drilling prospects in part through acquisitions and organic leasehold development.  Our strong balance sheet gives us the ability to move quickly when we find an acquisition target that we believe will be accretive to us and will help us build our inventory of quality drilling prospects.  We may also divest selected non-core assets when market conditions and prices are attractive, as evidenced by our announced divestiture program.  We continuously evaluate opportunities in the marketplace for oil and gas properties and, accordingly, we may be a buyer or a seller of properties at various times.

**A quarter and nine-month overview of selected production and financial information, including trends:**

Selected Operations Data (In thousands, except sales price, volume, and per MCFE amounts):

| | For the Three Months Ended September 30, 2007 | For the Three Months Ended September 30, 2006 | % of Change Between Periods | For the Nine Months Ended September 30, 2007 | For the Nine Months Ended September 30, 2006 | % of Change Between Periods |
|---|---|---|---|---|---|---|
| Net production volumes | | | | | | |
| Oil (MBbls) | 1,796 | 1,496 | 20% | 5,203 | 4,454 | 17% |
| Natural gas (MMcf) | 16,675 | 14,182 | 18% | 47,743 | 40,994 | 16% |
| MCFE (6:1) | 27,453 | 23,160 | 19% | 78,962 | 67,717 | 17% |
| Average daily production | | | | | | |
| Oil (Bbls per day) | 19,526 | 16,265 | 20% | 19,060 | 16,314 | 17% |
| Natural gas (Mcf per day) | 181,249 | 154,154 | 18% | 174,881 | 150,162 | 16% |
| MCFE per day (6:1) | 298,405 | 251,742 | 19% | 289,240 | 248,046 | 17% |
| Oil & gas production revenues[(1)] | | | | | | |
| Oil production | $ 121,365 | $ 91,693 | 32% | $ 313,118 | $ 260,135 | 20% |
| Gas production | 117,305 | 101,294 | 16% | 361,399 | 304,854 | 19% |
| Total | $ 238,670 | $ 192,987 | 24% | $ 674,517 | $ 564,989 | 19% |
| Oil & gas production expense | | | | | | |
| Lease operating expenses | $ 36,861 | $ 30,109 | 22% | $ 102,615 | $ 84,733 | 21% |
| Transportation costs | 3,169 | 2,371 | 34% | 11,775 | 7,966 | 48% |
| Production taxes | 14,940 | 12,518 | 19% | 43,228 | 36,791 | 17% |
| Total | $ 54,970 | $ 44,998 | 22% | $ 157,618 | $ 129,490 | 22% |
| Average realized sales price, before hedging | | | | | | |
| Oil (per Bbl) | $ 71.68 | $ 65.02 | 10% | $ 61.97 | $ 61.83 | -% |
| Natural gas (per Mcf) | $ 5.98 | $ 6.41 | (7)% | $ 6.63 | $ 6.70 | (1)% |
| Average realized sales price, net of hedging | | | | | | |
| Oil (per Bbl) | $ 67.56 | $ 61.28 | 10% | $ 60.18 | $ 58.41 | 3% |
| Natural gas (per Mcf) | $ 7.03 | $ 7.14 | (2)% | $ 7.57 | $ 7.44 | 2% |
| Per MCFE Data: | | | | | | |
| Average realized sales price, before hedging | $ 8.32 | $ 8.12 | 2% | $ 8.08 | $ 8.12 | -% |
| | $ 8.69 | $ 8.33 | 4% | $ 8.54 | $ 8.34 | 2% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Average realized sales price, net of hedging | | | | | | | | | |
| Lease operating expense | | (1.34) | | (1.30) | 3% | | (1.30) | | (1.25) | 4% |
| Transportation | | (0.12) | | (0.10) | 20% | | (0.15) | | (0.12) | 25% |
| Production taxes | | (0.54) | | (0.54) | -% | | (0.55) | | (0.54) | 2% |
| General and administrative | | (0.48) | | (0.42) | 14% | | (0.48) | | (0.46) | 4% |
| Operating margin | $ | 6.21 | $ | 5.97 | 4% | $ | 6.06 | $ | 5.97 | 2% |
| | | | | | | | | | | |
| Depletion, depreciation, amortization, and asset retirement obligation liability accretion | $ | 2.15 | $ | 1.72 | 25% | $ | 2.06 | $ | 1.63 | 26% |

(1) Includes the effects of our hedging activities

*Financial Information (In Thousands, Except Per Share Amounts):*

| | September 30, 2007 | December 31, 2006 | % of Change Between Periods |
|---|---|---|---|
| Working capital (deficit) | $ (52,828) | $ 22,870 | (331)% |
| Long-term debt | $ 442,500 | $ 433,980 | 2% |
| Stockholders' equity | $ 933,194 | $ 743,374 | 26% |

| | For the Three Months Ended September 30, 2007 | For the Three Months Ended September 30, 2006 | % of Change Between Periods | For the Nine Months Ended September 30, 2007 | For the Nine Months Ended September 30, 2006 | % of Change Between Periods |
|---|---|---|---|---|---|---|
| Basic net income per common share | $ 0.91 | $ 1.01 | (10)% | $ 2.56 | $ 2.59 | (1)% |
| Diluted net income per common share | $ 0.89 | $ 0.88 | 1% | $ 2.43 | $ 2.25 | 8% |
| Basic weighted-average shares outstanding | 63,424 | 55,398 | 14% | 61,364 | 56,564 | 8% |
| Diluted weighted-average shares outstanding | 64,727 | 64,926 | -% | 64,917 | 66,332 | (2)% |

We present this table as a summary of information relating to key indicators of financial condition and operating performance that we believe are important.

We present per MCFE information because we use this information to evaluate our performance relative to our internal targets as well as our peers, and to identify and measure trends that we believe require analysis. Our quarter-to-quarter comparison of financial results presented later provides additional details and analysis of changes between the quarters in selected line items. We expect oil and gas production expenses to increase slightly throughout 2007 as a result of increased production from higher cost oil projects in the Permian region. Depreciation, depletion, and amortization per MCFE will continue to significantly increase due to higher costs associated with finding and acquiring oil and gas reserves. We expect general and administrative expense to increase in the fourth quarter of 2007 as compared to the third quarter as a result of adding additional employees and the overall upward pressure on compensation in the exploration and production industry. Additionally, variability in this expense will be affected by commodity prices that impact Net Profits Plan payments and the impact of changes to estimates of bonus compensation.

We have in-the-money stock options and unvested RSUs that are considered potentially dilutive securities. At times these dilutive securities can affect our earnings per share. Consequently, both basic and diluted earnings per share are presented in the table above. We are accounting for the potentially dilutive shares related to our 3.50% Convertible Notes under the treasury stock method. As a result, there is no impact on the diluted share calculation at the current time since our stock price is not above the conversion price for the issuance. A detailed explanation is presented in Note 4 – Earnings Per Share in Part I, Item 1 of this report. Basic and diluted weighted-average common shares outstanding used in our earnings per share calculations for the three-month periods ended September 30, 2007, and 2006, reflect an increase in outstanding shares related to stock option exercises. We issued 471,320 and 1,371,313 shares of common stock during the nine-month periods ended September 30, 2007, and 2006, respectively, as a result of stock

option exercises. The remaining information in the table relates to information we have provided in our operations update press releases and is intended to supplement the discussion above.

**Overview of Liquidity and Capital Resources**

We believe that we have sufficient liquidity and capital resources to execute our business plan for the foreseeable future.

*Sources of Cash*

Our current expectation is that total 2007 capital investment under the drilling and acquisition program will exceed our cash flow generated from operations. We have been aided greatly this year by higher commodity prices so our estimated cash flow from operations is approximately $140 million higher than we originally budgeted. This amount has been used to reduce the amount of borrowings required under our revolving credit facility, even as we increased our overall capital investment program. Accordingly, we expect to access cash funding through the use of our revolving credit facility. We expect to use proceeds from the property divestiture package to reduce outstanding borrowings under the revolving credit facility.

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-strategic properties, and cash raised through the capital markets. All of these sources can be impacted by the general condition of our industry and by significant fluctuations in oil and natural gas prices, operating costs, and volumes produced. We have no control over market prices for oil and natural gas, although we are able to influence the amount of our net revenues related to oil and gas sales through the use of derivative contracts. A decrease in market prices for commodities would reduce expected cash flow from operating activities and could reduce the borrowing base of our credit facility as well as the value of non-strategic properties we may consider selling. Historically, decreases in market prices for commodities have limited our industry's access to the capital markets. The debt and equity capital markets are currently favorable to energy companies that operate in the exploration and production industry. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in our industry.

*Our Current Credit Facility*

We have a five-year, $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank, and eight other participating banks. This credit facility has a borrowing base currently set at $1.25 billion, and we have elected a commitment amount of $500 million. We believe this commitment level is adequate for our near-term liquidity requirements. The credit agreement has a maturity date of April 7, 2010. We must comply with certain financial and non-financial covenants, and we are currently in compliance with all of those covenants. We had $210 million of available borrowing capacity under this facility as of the date of this filing. Interest and commitment fees are accrued based on the borrowing base utilization percentage. Euro-dollar loans accrue interest at LIBOR plus the applicable margin from the utilization table, and Alternate Base Rate loans accrue interest at Prime plus the applicable margin from the utilization table. This table is located in Note 7 – Long-term Debt in Part I, Item 1 of this report. Any outstanding letter-of-credit reduce the amount available under the commitment amount on a dollar-for-dollar basis. Borrowings under the facility are secured by mortgages on the majority of our oil and gas properties and by a pledge of the common stock of our material subsidiary companies.

Commitment fees are accrued on the unused portion of the aggregate commitment amount and are included in interest expense in the consolidated statements of operations. We had an outstanding loan balance of $155.0 million as of September 30, 2007, comprised entirely of Euro-dollar based borrowings.

Our weighted-average interest rate paid for the three- and nine- month periods ended September 30, 2007, was 5.1 percent and 5.9 percent, respectively and included fees paid on the unused portion of the credit facility's aggregate commitment amount and amortization of deferred financing costs associated with the 3.50% Convertible Notes.

*Uses of Cash*

We use cash for the acquisition, exploration, and development of oil and gas properties and for the payment of debt obligations, trade payables, general and administrative costs, income taxes, common stock repurchases, and stockholder dividends. In the first nine months of 2007 we spent $500.1 million for capital development and $32.7 million on acquisitions. These cash outflows were funded using cash inflows from operations and available borrowing capacity under our revolving credit facility.

During the third quarter of 2007, we purchased 790,816 shares of our common stock in the open market at a weighted-average price of $32.76, including commissions, for a total of $25.9 million. We have Board authorization to repurchase up to an additional 5.2 million shares of our common stock under our stock repurchase program. Shares may be repurchased from time to time in open market transactions or privately negotiated transactions subject to market conditions and other factors including certain provisions of our existing bank credit facility agreement, compliance with securities laws, and the terms and provisions of our stock repurchase program.

On May 14, 2007, we paid $3.1 million in dividends to stockholders of record as of the close of business May 4, 2007. Our intention is to continue to make these dividend payments for the foreseeable future subject to our future earnings, our financial condition, possible credit facility covenants, and other currently unexpected factors which could arise.

The following table presents amounts and percentage changes in cash flows between the nine-month periods ending September 30, 2007, and 2006. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part I, Item 1 of this report.

| | For the Nine Months Ended September 30, 2007 | 2006 | Change | Percent Change |
|---|---|---|---|---|
| | (In thousands) | | | |
| Net cash provided by operating activities | $ 473,982 | $ 317,549 | $ 156,433 | 49% |
| Net cash used in investing activities | $ (540,357) | $ (302,648) | $ (237,709) | 79% |
| Net cash provided by (used in) financing activities | $ 82,151 | $ (28,810) | $ 110,961 | 385% |

*Analysis of cash flow changes between the nine-month periods ended September 30, 2007, and September 30, 2006*

*Operating activities*. Cash received from oil and gas sales, net of the effects of hedging, increased $56.1 million to $670.7 million for the nine-month period ended September 30, 2007, from $614.6 million for the nine-month period ended September 30, 2006. This increase was the result of a 17 percent increase in production volumes and a two percent increase in our net realized price after hedging, resulting in a 19 percent increase in production revenue. The benefits derived from the production and pricing were somewhat offset by an increase in oil and gas production expense.

*Investing activities*. Cash proceeds from an insurance settlement related to Hurricane Rita totaled $7.1 million for the nine-month period ended September 30, 2007. Total cash outflow for 2007 capital

expenditures for leasehold and drilling activities increased $206.1 million or 70 percent, and cash outflow related to the acquisition of oil and gas properties increased $22.7 million, or 229 percent, compared to the same period in 2006. Cash received from short-term investments classified as available-for-sale, increased $1.5 million for the nine-month period ended September 30, 2007, as compared to the same period in 2006, whereas deposits paid to short-term investments available-for-sale increased $1.2 million for the nine-month period ended September 30, 2007, as compared to the same period in 2006. Cash paid for deposits related to the acquisition of oil and gas assets increased $15.3 million for the nine-month period ended September 30, 2007, as compared to the same period in 2006.

*Financing activities*. Net repayments against our credit facility increased $245.0 million for the nine-month period ended September 30, 2007, compared with the same period in 2006. Payments against our short-term note payable increased $4.5 million for the nine-month period ended September 30, 2007, compared with the same period in 2006. We received $280.7 million, net of $6.8 million of deferred financing costs, from the issuance of convertible debt for the nine-month period ended September 30, 2007. Our income tax benefit attributable to the exercise of stock options decreased $7.5 million to $7.7 million for the nine months ended September 30, 2007. We received $9.7 million less from the sale of common stock related to stock option exercises and issuance under the employee stock purchase plan in the nine-month period ended September 30, 2007, compared to the same period in 2006. We spent $97.2 million less to repurchase shares of our common stock in the nine-month period ended September 30, 2007, compared to the same period in 2006.

*Capital Expenditure Forecast*

We use our capital resources primarily for the exploration and development of oil and gas properties and for acquisitions. Our capital expenditures forecast for drilling remains at approximately $727 million. This amount excludes non-cash asset retirement obligation capitalized assets. Anticipated 2007 exploration and development expenditures for each of our regions are presented in the following table. We estimate a slight amount of increased capital investment in our Gulf Coast region, which will be offset by decreases in the Rockies and ArkLaTex regional investments. The precise amount to be invested in the 2007 drilling program in each region cannot be predicted but should be representative of the amounts presented below.

| | Exploration and Development Expenditures (In millions) |
|---|---|
| Mid-Continent region | $ 206 |
| Rocky Mountain region | 144 |
| ArkLaTex region | 123 |
| Permian Basin region | 126 |
| Gulf Coast region | 70 |
| Hanging Woman Basin CBM | 58 |
| | $ 727 |

We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements, regional cost inflation, and other factors. It is important to note that strong commodity prices have decreased the amount by which we forecast outspending our positive cash flows. The above allocations are subject to change based on these factors and the timing of drilling operations.

The following table sets forth certain information regarding the costs incurred by us in our oil and gas property acquisition, exploration, and development activities, whether capitalized or expensed.

| | For the Nine Months Ended September 30, | |
|---|---|---|
| | 2007 | 2006 |
| | (In thousands) | |
| Development costs | $ 411,076 | $ 248,168 |
| Exploration costs | 98,650 | 100,068 |
| Acquisitions: | | |
| Proved | 32,876 | 21,660 |
| Unproved | (225) | - |
| Leasehold | 35,686 | 19,597 |
| Total, including asset retirement obligation | $ 578,063 | $ 389,493 |

Costs incurred for capital and exploration activities during the first nine months of 2007 increased $188.6 million, or 48 percent, compared to the same period in 2006. Excluding acquisitions, our development and exploration spending has increased $161.5 million compared to the same nine-month period in the prior year. The significant percentage increase in leasehold costs reflect a focus on gaining access to leasehold in developing oil and gas plays.

We believe internally generated cash flows together with the cash available under our credit facility will be sufficient to fund our planned operational, drilling, and acquisition expenditures for the foreseeable future. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available economic acquisition and drilling opportunities, our cash flows from operating and financing activities, and our ability to assimilate acquisitions we make. Also, the impact of oil and gas prices on investment opportunities, the availability of capital and borrowing facilities, and the success of our development and exploratory activities may lead to changes in funding requirements for future development.

*Financing alternatives*

The debt and equity capital markets remain attractive to energy companies that operate in the exploration and production segment. This is a result of strong commodity prices and the general strength reflected in the balance sheets of the companies in our industry.

In April 2007 we completed the private placement of $287.5 million of 3.50% Convertible Notes as discussed in Note 7 - Long-term Debt of Part I, Item 1 of this report.

*Commodity Price Risk and Interest Rate Risk*

We are exposed to market risk, including the effects of changes in oil and gas commodity prices and changes in interest rates as discussed below. Since we produce and sell crude oil, natural gas and natural gas liquids, our financial results are affected when prices for these commodities fluctuate. In order to reduce the impact of fluctuations in commodity prices, we enter into hedging transactions. Changes in interest rates can affect the amount of interest we earn on our cash, cash equivalents, and short-term investments and the amount of interest we pay on borrowings under our revolving credit facility. Changes in interest rates do not affect the amount of interest we pay on our fixed rate convertible notes, but do affect the fair value of that debt. We anticipate that all hedge and derivative contract transactions will occur as expected.

There has been no material change to the natural gas and crude oil price sensitivity analysis previously disclosed. Please see the corresponding section under Part II, Item 7 of our Annual Report on Form 10-K/A for the year ended December 31, 2006.

*Summary of Oil and Gas Production Hedges in Place*

Our oil and natural gas derivative contracts include swap and collar arrangements. All contracts are entered into for other than trading purposes.

Our net realized oil and gas prices are impacted by hedges we have placed on future estimated production. We have historically entered into hedges of existing production around the time we make acquisitions of producing oil and gas properties. Our intent has been to lock in a significant portion of an equivalent amount of existing production to the prices we used to evaluate the risked economics of our acquisitions. We also hedge a portion of our future production on a discretionary basis.

In a typical commodity swap agreement, if the agreed-upon published, third-party index price is lower than the swap fixed price, we receive the difference between the index price per unit of production and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, we pay the difference. For collar agreements, if the price of the agreed upon third-party index is lower than the contracted floor price, we receive the difference below such contract price for each unit of production hedged. Conversely, we pay the difference between the agreed upon contracted ceiling price and the index price only if the index price is above the contracted ceiling price.

As of the date of this filing, our hedged positions of anticipated future production through 2011 totaled approximately 13 million Bbls of crude oil, 79 million MMBtu of natural gas, and 1 million Bbls of natural gas liquids. We seek to minimize basis risk and index the majority of our oil contracts to NYMEX prices and our gas contracts to various regional index prices associated with pipelines in proximity to our areas of gas production.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of September 30, 2007.

**Oil Contracts**

Oil Swaps

| Contract Period | Volumes (Bbl) | Weighted-Average Contract Price (Per Bbl) | Fair Value at September 30, 2007 (Liability) (In thousands) |
|---|---|---|---|
| Fourth quarter 2007 | | | |
| WCS | 30,000 | $ 47.82 | $ (347) |
| NYMEX WTI | 474,620 | $ 64.68 | (7,309) |
| 2008 | | | |
| WCS | 150,000 | $ 52.85 | (504) |
| NYMEX WTI | 1,795,000 | $ 69.17 | (12,694) |
| 2009 | | | |
| NYMEX WTI | 1,363,000 | $ 67.74 | (7,351) |
| 2010 | | | |
| NYMEX WTI | 1,239,000 | $ 66.47 | (6,252) |
| 2011 | | | |
| NYMEX WTI | 1,032,000 | $ 65.36 | (5,379) |
| All oil swap contracts | | | $ (39,836) |

Oil Collars

| Contract Period | NYMEX WTI Volumes (Bbl) | Weighted-Average Floor Price (Per Bbl) | Weighted-Average Ceiling Price (Per Bbl) | Fair Value at September 30, 2007 (Liability) (In thousands) |
|---|---|---|---|---|
| Fourth quarter 2007 | 689,000 | $ 51.58 | $ 72.81 | $ (5,529) |
| 2008 | 1,668,000 | $ 50.00 | $ 69.82 | (15,369) |
| 2009 | 1,526,000 | $ 50.00 | $ 67.31 | (14,129) |
| 2010 | 1,367,500 | $ 50.00 | $ 64.91 | (13,013) |
| 2011 | 1,236,000 | $ 50.00 | $ 63.70 | (11,734) |
| All oil collars | | | | $ (59,774) |

**Gas Contracts**

Natural Gas Swaps

| Contract Period | Volumes (MMBtu) | Weighted-Average Contract Price (Per MMBtu) | Fair Value at September 30, 2007 Asset/(Liability) (In thousands) |
|---|---|---|---|
| Fourth quarter 2007 - | | | |
| IF CIG | 780,000 | $ 7.56 | $ 3,449 |
| IF PEPL | 1,410,000 | $ 8.13 | 3,001 |
| IF NGPL | 1,220,000 | $ 8.07 | 2,493 |
| IF ANR OK | 850,000 | $ 7.74 | 1,478 |
| IF EL PASO | 210,000 | $ 7.17 | 240 |
| IF HSC | 970,000 | $ 7.60 | 924 |
| 2008 - | | | |
| IF CIG | 3,120,000 | $ 7.48 | 3,362 |
| IF PEPL | 5,780,000 | $ 8.07 | 7,526 |
| IF NGPL | 920,000 | $ 6.99 | 186 |
| IF ANR OK | 920,000 | $ 7.15 | 298 |
| IF EL PASO | 1,060,000 | $ 7.22 | 207 |
| IF HSC | 4,900,000 | $ 8.18 | 2,524 |
| 2009 - | | | |
| IF CIG | 1,710,000 | $ 7.79 | 1,241 |
| IF PEPL | 3,360,000 | $ 8.06 | 2,624 |
| IF NGPL | 440,000 | $ 7.11 | (100) |
| IF ANR OK | 440,000 | $ 7.38 | 3 |
| IF EL PASO | 1,200,000 | $ 7.11 | (407) |
| IF HSC | 6,320,000 | $ 8.35 | 2,255 |
| 2010 - | | | |
| IF NGPL | 60,000 | $ 7.60 | (27) |
| IF ANR OK | 60,000 | $ 7.98 | (11) |
| IF EL PASO | 1,090,000 | $ 6.79 | (574) |
| IF HSC | 3,460,000 | $ 8.25 | 1,034 |
| 2011 -- | | | |
| IF EL PASO | 880,000 | $ 6.34 | (629) |
| All gas swap contracts | | | $ 31,097 |

Natural Gas Collars

| Contract Period | Volumes (MMBtu) | Weighted-Average Floor Price (Per MMBtu) | Weighted-Average Ceiling Price (Per MMBtu) | Fair Value at September 30, 2007 Asset/(Liability) (In thousands) |
|---|---|---|---|---|
| Fourth quarter 2007 - | | | | |
| IF CIG | 730,000 | $ 6.41 | $ 7.87 | $ 2,444 |
| IF PEPL | 1,820,000 | $ 7.00 | $ 9.28 | 2,141 |
| IF HSC | 270,000 | $ 7.66 | $ 9.10 | 312 |
| NYMEX Henry Hub | 180,000 | $ 8.00 | $ 9.45 | 202 |
| 2008 - | | | | |
| IF CIG | 2,880,000 | $ 5.60 | $ 8.72 | 415 |
| IF PEPL | 6,600,000 | $ 6.28 | $ 9.42 | 2,252 |
| IF HSC | 960,000 | $ 6.57 | $ 9.70 | 16 |
| NYMEX Henry Hub | 480,000 | $ 7.00 | $ 10.57 | 69 |
| 2009 - | | | | |
| IF CIG | 2,400,000 | $ 4.75 | $ 8.82 | (833) |
| IF PEPL | 5,510,000 | $ 5.30 | $ 9.25 | (1,685) |
| IF HSC | 840,000 | $ 5.57 | $ 9.49 | (424) |
| NYMEX Henry Hub | 360,000 | $ 6.00 | $ 10.35 | (137) |
| 2010 - | | | | |
| IF CIG | 2,040,000 | $ 4.85 | $ 7.08 | (1,513) |
| IF PEPL | 4,945,000 | $ 5.31 | $ 7.61 | (3,064) |
| IF HSC | 600,000 | $ 5.57 | $ 7.88 | (510) |
| NYMEX Henry Hub | 240,000 | $ 6.00 | $ 8.38 | (178) |
| 2011- | | | | |
| IF CIG | 1,800,000 | $ 5.00 | $ 6.32 | (1,265) |
| IF PEPL | 4,225,000 | $ 5.31 | $ 6.51 | (3,802) |
| IF HSC | 480,000 | $ 5.57 | $ 6.77 | (533) |
| NYMEX Henry Hub | 120,000 | $ 6.00 | $ 7.25 | (115) |
| All gas collars | | | | $ (6,208) |

**Natural Gas Liquid Contracts**

Natural Gas Liquid Swaps

| Contract Period | Mont. Belvieu Volumes (Bbls) | Weighted-Average Contract Price (Per Bbl) | Fair Value at September 30, 2007 (Liability) (In thousands) |
|---|---|---|---|
| Fourth quarter 2007 | 132,888 | $ 39.49 | $ (1,826) |
| 2008 | 732,748 | $ 39.18 | (5,684) |
| 2009 | 627,179 | $ 38.61 | (2,692) |
| All natural gas liquid swaps | | | $ (10,202) |

Please see Note 8 – Derivative Financial Instruments in Part I, Item 1 of this report for additional information regarding our oil and gas hedges.

*Contractual Obligations*

On April 4, 2007, we issued $287.5 million aggregate principal amount of 3.50% Convertible Notes. For purposes of contractual obligations, we assume that the holders of our 3.50% Convertible Notes will not exercise the conversion feature and we will therefore have to repay the $287.5 million in cash. We expect to call the 3.50% Convertible Notes for redemption in 2012. We are also obligated to make annual interest payments equal to $10.1 million.

*Off-Balance Sheet Arrangements*

We carry no off-balance sheet financing other than operating leases, nor do we have any unconsolidated subsidiaries.

**Critical Accounting Policies and Estimates**

We refer you to the corresponding section in Part II, Item 7 of our Annual Report on Form 10-K/A for the year ended December 31, 2006, and to the footnote disclosures included in Part I, Item 1 of this report.

***Additional Comparative Data in Tabular Form:***

| Oil and gas production revenues | Change Between the Three Months Ended September 30, 2007, and 2006 | | Change Between the Nine Months Ended September 30, 2007, and 2006 | |
|---|---|---|---|---|
| Increase in oil and gas production revenues, net of hedging (in thousands) | $ | 45,683 | $ | 109,528 |
| *Components of Revenue Increases (Decreases):* | | | | |
| Oil | | | | |
| Realized price change per Bbl | $ | 6.28 | $ | 1.77 |
| Realized price percentage change | | 10% | | 3% |
| Production change (MBbl) | | 300 | | 749 |
| Production percentage change | | 20% | | 17% |
| Natural Gas | | | | |
| Realized price change per Mcf | $ | (0.11) | $ | 0.13 |
| Realized price percentage change | | (2)% | | 2% |
| Production change (MMcf) | | 2,493 | | 6,749 |
| Production percentage change | | 18% | | 16% |

*Our Product Mix as a Percentage of Total Oil and Gas Revenue and Production:*

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| Revenue | 2007 | 2006 | 2007 | 2006 |
| Oil | 51% | 48% | 46% | 46% |
| Natural gas | 49% | 52% | 54% | 54% |
| Production | | | | |
| Oil | 39% | 39% | 40% | 39% |
| Natural gas | 61% | 61% | 60% | 61% |

*Information Regarding the Components of Exploration Expense:*

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Summary of Exploration Expense | (In millions) | | (In millions) | |
| Geological and geophysical expenses | $ 4.4 | $ 1.8 | $ 9.4 | $ 6.1 |
| Exploratory dry hole expense | 1.5 | 0.4 | 12.7 | 4.0 |
| Overhead and other expenses | 9.4 | 7.6 | 27.6 | 25.8 |
| Total | $ 15.3 | $ 9.8 | $ 49.7 | $ 35.9 |

*Information Regarding the Effects of Oil and Gas Hedging Activity:*

| | For the Three Months Ended September 30, | | For the Nine Months Ended September 30, | |
|---|---|---|---|---|
| Oil Hedging | 2007 | 2006 | 2007 | 2006 |
| Percentage of oil production hedged | 64% | 64% | 65% | 67% |
| Oil volumes hedged (MBbl) | 1,154 | 962 | 3,371 | 2,987 |
| Decrease in oil revenue | $(7.4 million) | $(5.6 million) | $(9.3 million) | $(15.3 million) |
| Average realized oil price per Bbl before hedging | $ 71.68 | $ 65.02 | $ 61.97 | $ 61.83 |
| Average realized oil price per Bbl after hedging | $ 67.56 | $ 61.28 | $ 60.18 | $ 58.41 |
| Natural Gas Hedging | | | | |
| Percentage of gas production hedged | 47% | 47% | 47% | 42% |
| Natural gas MMBtu hedged | 8.2 million | 7.1 million | 23.6 million | 18.3 million |
| Increase in gas revenue | $17.6 million | $10.4 million | $45.5 million | $30.1 million |
| Average realized gas price per Mcf before hedging | $ 5.98 | $ 6.41 | $ 6.63 | $ 6.70 |
| Average realized gas price per Mcf after hedging | $ 7.03 | $ 7.14 | $ 7.57 | $ 7.44 |

***Comparison of Financial Results and Trends between the Quarters ended September 30, 2007, and 2006***

*Oil and gas production revenue*. Average net daily production increased 19 percent to a new quarterly record at 298.4 MMCFE per day for the third quarter of 2007, compared with 251.7 MMCFE per day for the same quarter in 2006. The following table presents specific components that contributed to the increase in revenue between the two quarters:

| | Average Net Daily Production Added (MMCFE) | Oil and Gas Revenue Added (In millions) | Production Costs Added (In millions) |
|---|---|---|---|
| Sweetie Peck acquisition and drilling, Permian Basin region | 15.6 | $ 16.5 | $ 2.6 |
| Williston Basin Middle Bakken Play | 1.9 | 1.9 | 0.7 |
| Elm Grove Field | 5.6 | 2.9 | 0.4 |
| James Lime formation | 3.3 | 1.4 | 0.3 |
| Anadarko Basin fields | 7.3 | 4.5 | 0.9 |
| Woodford shale formation – horizontal wells | 6.7 | 3.0 | 0.2 |
| Other wells completed in 2006 and 2007 | 29.9 | 18.7 | 2.6 |
| Other acquisitions | 4.0 | 2.8 | 1.0 |
| Total | 74.3 | $ 51.7 | $ 8.7 |

The revenue increases in this table also reflect the difference in oil and gas prices received between the comparable periods. The production increases are offset by natural declines in production from older properties to result in the net increase in production between the quarters presented. Additional production costs reflect increases resulting from inflation and competition for resources.

*Marketed gas system revenue and expense.* Marketed gas system revenue increased $3.5 million to $7.4 million for the quarter ended September 30, 2007, compared with $3.9 million for the comparable period of 2006. The increase is due to the addition of a new marketed gas system in western Oklahoma that increased the number of wells for which we currently market gas, as well as increased production in the Woodford shale formation located in Coal County, Oklahoma. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $4.2 million to $7.3 million for the quarter ended September 30, 2007, compared with $3.1 million for the comparable period of 2006. The net margin has stayed consistent with historical performance.

*Oil and gas production expense.* Total production costs increased $10.0 million, or 22 percent, to $55.0 million for the third quarter of 2007 from $45.0 million in the comparable period of 2006. Total oil and gas production costs per MCFE increased $0.06 to $2.00 for the third quarter of 2007, compared with $1.94 for the same quarter in 2006. This increase is comprised of the following:

- A $0.01 increase in overall transportation cost due to an increase in the Rocky Mountain region resulting from a change in the sale measurement point, as well as newly drilled wells with higher transportation costs; partially offset by decreases in the other regions;
- A $0.16 increase in recurring lease operating expense related to continued cost pressure in oil and gas service sector labor resources and an absolute increase from higher cost oil properties acquired in the fourth quarter of 2006 as part of the Sweetie Peck acquisition;
- A $0.12 overall decrease in lease operating expense relating to workover expenses from our Rocky Mountain region; and
- A $0.01 increase in production taxes.

*Depletion, depreciation, amortization, and asset retirement obligation liability accretion*. DD&A increased $19.2 million, or 48 percent, to $59.1 million for the three-month period ended September 30, 2007, compared with $39.8 million for the same period in 2006. DD&A expense per MCFE increased 25 percent to $2.15 for the three-month period ended September 30, 2007, compared to $1.72 for the same period in 2006. This increase reflects the higher costs to acquire and develop oil and gas assets experienced by the industry in recent years. In addition to the increasing rate, our production has increased by 19 percent over the comparable periods, contributing to the absolute increase.

*Exploration Expense*. Exploration expense increased $5.5 million, or 56 percent, to $15.3 million for the third quarter of 2007, compared with $9.8 million for the comparable period of 2006. The increase is due in part to $2.6 million in geological and geophysical expense related to seismic work performed in the Anadarko Basin. Exploration overhead expense also increased $1.8 million due to the overall upward pressure on compensation in the exploration and production industry, as well as an increase in payments made under the Net Profits Plan.

*General and administrative.* General and administrative expenses increased $3.4 million or 35 percent to $13.1 million for the quarter ended September 30, 2007, compared with $9.7 million for the comparable period of 2006. G&A increased $0.06 to $0.48 per MCFE for the third quarter of 2007 compared to $0.42 per MCFE for the same three-month period in 2006.

An increase in employee count has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $2.8 million between the third quarter of 2007 and the third quarter of 2006. A $300,000 increase in Net Profits Plan payments is the result of the timing of payout on newer pools. The 2004 pool reached payout status at the end of the first quarter of 2007. As of the end of the third quarter of 2007, 17 of 20 pools are in payout status. No additional pools are expected to reach payout before the end of 2007.

RSU bonus expense for the quarter ended September 30, 2007, increased $482,000 to $2.1 million from $1.6 million in the comparable period in 2006. Cash bonus expense for the quarter ended September 30, 2007, increased $1.0 million to $1.7 million from $700,000 in the comparable period in 2006. The increases are caused by an increase in employee count and base compensation. Compensation expense related to stock options for the quarter ended September 30, 2007, decreased $596,000 to $27,000 from $623,000 in the comparable period in 2006 because virtually all the stock options are now vested. No stock options have been granted since 2004.

The above amounts combined with a net $1.5 million increase in other G&A expense, including professional fees and charitable contributions expense, were offset by a $600,000 increase in the amount of

general and administrative expense that was allocated to exploration expense due to the increase in the size of our geological and exploration staff, as well as a $1.3 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count that resulted from our drilling and acquisition programs.

*Change in Net Profits Plan Liability*. For the third quarter of 2007, this non-cash expense changed by $6.9 million, resulting in an increase in the liability of $3.1 million in 2007 as compared to a reduction of the liability of $3.7 million for the same quarter in 2006. The change is due to an increase in future estimated payments caused primarily by an increase in projected oil prices. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

*Income taxes*. Income tax expense totaled $34.0 million for the third quarter of 2007 and $29.3 million for the third quarter of 2006 resulting in effective tax rates of 37.1 percent and 34.4 percent, respectively. Our effective income tax rate changes from period to period as a result of changes in the mix of the highest marginal state tax rates where we do business due to acquisition and drilling activity, changes in the effect of the domestic production activities deduction, and other miscellaneous permanent differences. Our cash tax expenses decreased for the third quarter of 2007 compared to the same period of 2006 as a result of a higher level of capital spending during the third quarter of 2007 that resulted in lower estimated current taxable income. This trend is expected to continue throughout the remainder of 2007 due to our current capital program and the commodity price outlook.

***Comparison of Financial Results and Trends between the nine months ended September 30, 2007, and 2006***

*Oil and gas production revenue*. Average net daily production increased 17 percent to 289.2 MMCFE per day for the nine months ended September 30, 2007, compared with 248.0 MMCFE per day for the nine months ended September 30, 2006. The following table presents specific components that contributed to the increase in revenue between the two periods:

| | Average Net Daily Production Added (MMCFE) | Oil and Gas Revenue Added (In millions) | Production Costs Added (In millions) |
|---|---|---|---|
| Sweetie Peck acquisition, Permian Basin region | 16.3 | $ 46.1 | $ 7.7 |
| Williston Basin Middle Bakken play | 3.0 | 8.6 | 1.5 |
| Elm Grove Field | 5.6 | 10.7 | 1.3 |
| James Lime formation | 4.1 | 7.9 | 1.0 |
| Anadarko Basin fields | 8.7 | 17.2 | 2.8 |
| Woodford shale formation – horizontal wells | 5.1 | 7.7 | 0.7 |
| Other wells completed in 2006 and 2007 | 38.6 | 65.2 | 9.8 |
| Other acquisitions | 4.4 | 9.6 | 2.6 |
| Total | 85.8 | $ 173.0 | $ 27.4 |

The revenue increases in this table also reflect the difference in oil and gas prices received between the comparable periods. The production increases are offset by natural declines in production

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from older properties resulting in the net increase in production between the quarters presented. Additional production costs reflect increases resulting from inflation and competition for resources.

*Marketed gas system revenue and expense.* Marketed gas system revenue increased $18.1 million to $31.2 million for the nine-month period ended September 30, 2007, compared with $13.1 million for the comparable period of 2006. The increase is due to the addition of a new marketed gas system in western Oklahoma that increased the number of wells for which we currently market gas, as well as increased production in the Woodford shale formation located in Coal County, Oklahoma. Concurrent with the increase in marketed gas system revenue, marketed gas system expense increased $18.3 million to $29.5 million for the nine-month period ended September 30, 2007, compared with $11.1 million for the comparable period of 2006.

*Other revenues.* Other revenues increased $9.4 million to $9.1 million for the nine-month period ended September 30, 2007, compared with an expense of $299,000 for the comparable period of 2006. The increase is due to a $6.3 million gain associated with a global insurance settlement attributed to Hurricane Rita. The gain calculation reflects approximately $10 million of future costs associated with plugging and abandonment of one offshore platform. Additionally, we have a remaining accrual of approximately $708,000 associated with expected hurricane related damage repair costs from our outside-operated properties. We continue to closely monitor the activities associated with these properties. Any significant variation between actual and estimated plugging and abandonment and outside-operated damage repair costs will impact the final determination of the insurance settlement gain. We assume that all work will be completed and expect adjustments to the gain will be finalized during the fourth quarter of 2007.

*Oil and gas production expense.* Total production costs increased $28.1 million, or 22 percent, to $157.6 million for the nine months ended September 30, 2007, from $129.5 million for the nine months ended September 30, 2006. Total oil and gas production costs per MCFE increased $0.09 to $2.00 for the nine months ended September 30, 2007, compared with $1.91 for the nine months ended September 30, 2006. This increase is comprised of the following:

- A $0.03 increase in overall transportation cost due to an increase in the Rocky Mountain region resulting from a change in the sale measurement point, as well as newly drilled wells with higher transportation costs;
- A $0.14 increase in recurring lease operating expense related to continued increases in competition for oil and gas service sector resources;
- A $0.09 overall decrease in lease operating expense relating to workover expense in the Rockies and;
- A $0.01 increase in production taxes.

*Depletion, depreciation, amortization, and asset retirement obligation liability accretion.* DD&A increased $52.6 million or 48 percent to $162.7 million for the nine-month period ended September 30, 2007, compared with $110.1 million for the same period in 2006. DD&A expense per MCFE increased 26 percent to $2.06 for the nine-month period ended September 30, 2007, compared to $1.63 for the same period in 2006. The remainder of the increase was associated with larger production volumes in the most recent quarter. This increase reflects the overall increase in costs to acquire and develop oil and gas properties that the industry has experienced in recent years.

*Exploration expense.* Exploration expense increased $13.8 million, or 38 percent, to $49.7 million for the nine-month period ended September 30, 2007, compared with $35.9 million for the comparable period of 2006. This increase is due in part to an $8.7 million increase in exploratory dry hole expense mainly related to two wells located in the Gulf Coast region and one in the Rockies region and a $3.3 million increase in geological and geophysical expense related to seismic work performed in the

Anadarko Basin contributed to the increase. Exploration overhead expense also increased $1.8 million due to the overall upward pressure on compensation in the exploration and production industry, as well as an increase in payments made under the Net Profits Plan.

*General and administrative.* General and administrative expenses increased $7.0 million, or 23 percent, to $37.9 million for the nine months ended September 30, 2007, compared with $30.9 million for the nine months ended September 30, 2006. G&A remained relatively flat at $0.48 per MCFE for the nine months ended September 30, 2007, compared to $0.46 per MCFE for the nine months ended September 30, 2006.

A 21 percent increase in employee headcount, reflecting our increased activity, has resulted in an increase in base employee compensation, including taxes and benefits, of approximately $6.1 million for the nine months ended September 30, 2007 compared with the same period of 2006. Costs associated with providing office space and support for the increasing number of employees are also increasing.

RSU bonus expense for the nine months ended September 30, 2007, increased $237,000 to $7.1 million from $6.9 million in the comparable period in 2006. Cash bonus expense for the nine months ended September 30, 2007, increased $1.4 million to $4.8 million from $3.4 million in the comparable period in 2006. The increases are caused by an increase in employee count and base compensation. Compensation expense related to stock options for the nine months ended September 30, 2007, decreased $1.2 million to $409,000 from $1.6 million in the comparable period in 2006 since more stock options vested in 2006 than 2007. Director fees expense for the nine months ended September 30, 2007, increased $408,000 to $988,000 from $580,000 in the comparable period in 2006 related to compensation expense associated with the issuance of common stock to the Board of Directors due to four out of the seven non-employee directors having served on the Board for more than five years. Any director retiring after five years of service becomes fully vested in all previous equity issues.

The above amounts combined with a net $3.2 million increase in other G&A expense, including professional fees and charitable contributions expense, were offset by a $1.7 million increase in the amount of general and administrative expense that was allocated to exploration expense due to the increase in the size of our geological and exploration staff, as well as a $2.8 million increase in COPAS overhead reimbursements. COPAS overhead reimbursements from operations increased due to an increase in our operated well count resulting from our drilling and acquisition programs.

*Change in Net Profits Plan Liability*. For the nine months ended September 30, 2007, this non-cash expense was $6.9 million compared to $17.4 million for the nine months ended September 30, 2006. The decrease is due to the effect of increased oil and gas production expense, additional capital expenditures, and a deferral of revenue due to the impact of discounting future revenues in those pools currently in payout status. This liability is a significant management estimate. Adjustments to the liability are subject to estimation and may change dramatically from period to period based on assumptions used for production rates, reserve quantities, commodity pricing, discount rates, tax rates, and production costs.

*Income taxes.* Income tax expense totaled $92.7 million for the nine months ended September 30, 2007, and $82.9 million for the nine months ended September 30, 2006, resulting in effective tax rates of 37.2 percent and 36.1 percent, respectively. Our current cash tax expense decreased for the nine months ended September 30, 2007, compared to the same nine-month period of 2006 as a result of a higher level of capital spending during 2007 that resulted in lower estimated current taxable income. The majority of income tax expense in 2007 is expected to be deferred to future years.

**Accounting Matters**

We refer you to Note 6 – Income Taxes and Note 7 – Long-term Debt included in Part I, Item 1 of this report for information regarding accounting matters related to FIN No. 48 and FSP APB 14-a..

**Environmental**

St. Mary's compliance with applicable environmental regulations has not resulted in any significant capital expenditures or materially adverse effects on our liquidity or results of operations. We believe that we are in substantial compliance with environmental regulations, and we do not currently expect that any material expenditure will be required in the foreseeable future. However, we are unable to predict the impact that future compliance with regulations may have on future capital expenditures, liquidity, and results of operations.

***Cautionary Information about Forward-Looking Statements***

*This Quarterly Report on Form 10-Q contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this Form 10-Q that address activities, events, or developments that we expect, believe, or anticipate will or may occur in the future are forward-looking statements. The words "anticipate," "assume," "believe," "budget," "estimate," "expect," "forecast," "intend," "plan," "project," "will," and similar expressions are intended to identify forward-looking statements. Forward-looking statements appear in a number of places in this Form 10-Q, and include statements about such matters as:*

- *The amount and nature of future capital expenditures and the availability of capital resources to fund capital expenditures;*
- *the drilling of wells and other exploration and development plans, as well as possible future acquisitions;*
- *reserve estimates and the estimates of both future net revenues and the present value of future net revenues that are included in their calculation;*
- *future oil and gas production estimates;*
- *our outlook on future oil and gas prices and service costs;*
- *cash flows, anticipated liquidity, and the future repayment of debt;*
- *business strategies and other plans and objectives for future operations, including plans for expansion and growth of operations and our outlook on future financial condition or results of operations; and*
- *other similar matters such as those discussed in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section of this Form 10-Q.*

*Our forward-looking statements are based on assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions, expected future developments, and other factors that we believe are appropriate under the circumstances. These statements are subject to a number of known and unknown risks and uncertainties which may cause our actual results to differ materially from results expressed or implied by the forward-looking statements. These risks are described in the "Risk Factors" section of our 2006 Annual Report on Form 10-K/A and in our subsequent filings with the SEC, and include such factors as:*

- *The volatility and level of realized oil and natural gas prices;*
- *unexpected drilling conditions and results;*
- *unsuccessful exploration and development drilling;*
- *the availability and risks of economically attractive exploration, development, and property acquisition opportunities and any necessary financing;*
- *the risks of hedging strategies;*
- *lower prices realized on oil and gas sales resulting from our commodity price risk management activities;*
- *the uncertain nature of the expected benefits from the acquisition of oil and gas properties;*
- *the pending nature of the reported divestiture plans for certain non-core oil and gas properties as well as the ability to complete the transaction;*
- *the uncertain nature of the expected benefits from the divestiture of oil and gas properties and the amount of expected proceeds to be received from the divestiture;*
- *production rates and reserve replacement;*
- *the imprecise nature of oil and gas reserve estimates;*
- *uncertainties inherent in projecting future rates of production from drilling activities and acquisitions;*
- *drilling and operating service availability;*
- *uncertainties in cash flow;*
- *the financial strength of hedge contract counterparties;*
- *the negative impact that lower oil and natural gas prices could have on our ability to borrow;*
- *our ability to compete effectively against other independent and major oil and gas companies; and*
- *litigation, environmental matters, the potential impact of government regulations, and the use of management estimates.*

*We caution you that forward-looking statements are not guarantees of future performance and that actual results or developments may differ materially from those expressed or implied in the forward-looking* *statements. Although we may from time to time voluntarily update our prior forward-looking statements, we disclaim any commitment to do so except as required by securities laws.*

**ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The information required by this item is provided under the captions “Commodity Price Risk and Interest Rate Risk,” and “Summary of Oil and Gas Production Hedges in Place” in Item 2 above and is incorporated herein by reference.

**ITEM 4. CONTROLS AND PROCEDURES**

We maintain a system of disclosure controls and procedures that are designed to ensure that information required to be disclosed in our SEC reports is recorded, processed, summarized, and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

We carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based upon that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures are effective for the purposes discussed above as of the end of the period covered by this Quarterly Report on Form 10-Q. There was no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

**PART II. OTHER INFORMATION**

**ITEM 1. LEGAL PROCEEDINGS**

From time to time, we may be involved in litigation relating to claims arising out of our operations in the normal course of business. As of the date of this report, no legal proceedings are pending against us that we believe individually or collectively could have a material adverse effect upon our financial condition or results of operations.

**ITEM 1A. RISK FACTORS**

There have been no material changes from the risk factors as previously disclosed in our Form 10-K/A for the year ended December 31, 2006, in response to Item 1A of Part I of such Form 10-K/A.

**ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS**

(c) The following table provides information about purchases by the Company or any "affiliated purchaser" (as defined in Rule 10b-18(a)(3) under the Exchange Act) during the fiscal quarter ended September 30, 2007, of shares of the Company's common stock, which is the sole class of equity securities registered by the Company pursuant to Section 12 of the Exchange Act.

**PURCHASES OF EQUITY SECURITIES BY ISSUER AND AFFILIATED PURCHASERS**

| | (a) | (b) | (c) | (d) |
|---|---|---|---|---|
| **Period** | **Total Number of Shares Purchased** (1) | **Average Price Paid per Share** | **Total Number of Shares Purchased as Part of Publicly Announced Program** | **Maximum Number of Shares that May Yet Be Purchased Under the Program** (2) |
| 07/01/07 – 07/31/07 | - 0 - | $- 0 - | -0- | 6,000,000 |
| 08/01/07 – 08/31/07 | - 791,816 - | $- 32.76 - | -790,816- | 5,209,184 |
| 09/01/07 – 09/30/07 | - 0 - | $- 0 - | -0- | 5,209,184 |
| Total: | - 791,816 - | $- 32.76 - | -790,816- | 5,209,184 |

(1) Includes a total of 1,000 shares purchased by Anthony J. Best, St. Mary's President and Chief Executive Officer, in open market transactions that were not made pursuant to our stock repurchase program. The table does not include the 678 shares purchased by Mr. Best under the Company's employee stock purchase plan.

(2) In July 2006 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original August 1998 authorization to 6,000,000 as of the effective date of the resolution. Accordingly, as of the date of this filing, the Company has Board authorization to repurchase 5,209,184 shares of common stock on a prospective basis. The shares may be repurchased from time to time in open market transactions or privately negotiated transactions, subject to market conditions and other factors, including certain provisions of St. Mary's existing bank credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow, and borrowings under St. Mary's bank credit facility. The stock repurchase program may be suspended or discontinued at any time.

The payment of dividends and stock repurchases are subject to covenants in our bank credit facility, including the requirement that we maintain certain levels of stockholders' equity and the limitation that does not allow our annual dividend rate to exceed $0.25 per share.

**ITEM 6. EXHIBITS**

The following exhibits are filed or furnished with or incorporated by reference into this report:

| Exhibit | Description |
|---|---|
| 2.1 | Purchase and Sale Agreement dated August 2, 2007, among Rockford Energy Partners II, LLC and St. Mary Land & Exploration Company (filed as Exhibit 2.1 to the registrant's Current Report on Form 8-K on October 4, 2007, and is incorporated herein by reference) |
| 10.1 | Net Profits Interest Bonus Plan, As Amended and Restated by the Board of Directors on July 19, 2007 (filed as Exhibit 10.1 to the registrant's Current Report on Form 8-K filed on July 25, 2007, and is incorporated herein by reference) |
| 31.1* | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002 |
| 31.2* | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes – Oxley Act of 2002 |
| 32.1** | Certification pursuant to U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes – Oxley Act of 2002 |
| 99.1* | Audit Committee Pre-Approval of Non-Audit Services |

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* Filed with this Form 10-Q.
** Furnished with this Form 10-Q.

## SIGNATURES

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

ST. MARY LAND & EXPLORATION COMPANY

| | |
|---|---|
| November 1, 2007 | By:/s/ ANTHONY J. BEST<br>Anthony J. Best<br>President and Chief Executive Officer |
| November 1, 2007 | By:/s/ DAVID W. HONEYFIELD<br>David W. Honeyfield<br>Senior Vice President - Chief Financial Officer, Secretary and Treasurer |
| November 1, 2007 | By:/s/ MARK T. SOLOMON<br>Mark T. Solomon<br>Controller |