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, 2005

Commission file number 001-31539

ST. MARY LAND & EXPLORATION COMPANY

(Exact name of registrant as specified in its charter)

Delaware	41-0518430
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1776 Lincoln Street, Suite 700, Denver, Colorado 80203
(Address of principal executive offices) (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 [X] No [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined by Rule 12b-2 of the Exchange Act).
Yes [X] No [ ]

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

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 24, 2005, the registrant had 56,564,222 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)

	September 30,	December 31,
ASSETS	2005	2004
Current assets:		
Cash and cash equivalents	$ 26,597	$ 6,418
Short-term investments	1,475	1,412
Accounts receivable	139,478	104,964
Prepaid expenses and other	8,403	5,863
Deferred income taxes	24,424	-
Accrued derivative asset	490	8,270
Total current assets	200,867	126,927
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	1,374,732	1,124,810
Less - accumulated depletion, depreciation and amortization	(468,858)	(399,013)
Unproved oil and gas properties, net of impairment allowance of $9,395 in 2005 and $9,867 in 2004	43,221	41,969
Wells in progress	50,736	35,515
Other property and equipment, net of accumulated depreciation of $7,616 in 2005 and $6,459 in 2004	5,446	5,244
	1,005,277	808,525
Noncurrent assets:		
Goodwill	9,797	-
Accrued derivative asset	96	115
Other noncurrent assets	5,309	9,893
Total noncurrent assets	15,202	10,008
Total Assets	**$ 1,221,346**	**$ 945,460**
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued expenses	$ 158,031	$ 110,117
Accrued derivative liability	66,331	2,502
Deferred income taxes	325	2,273
Total current liabilities	224,687	114,892
Noncurrent liabilities:		
Long-term credit facility	52,000	37,000
Convertible notes	99,862	99,791
Asset retirement obligation	53,547	40,911
Net Profits Interest Plan liability	101,814	30,561
Deferred income taxes	151,129	129,830
Accrued derivative liability	16,064	2,970
Other noncurrent liabilities	5,309	5,050
Total noncurrent liabilities	479,725	346,113
Commitments and contingencies		
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 200,000,000 shares; issued: 58,177,539 shares in 2005 and 57,458,246 shares in 2004; outstanding, net of treasury shares: 56,533,655 shares in 2005 and 56,958,246 shares in 2004	582	574
Additional paid-in capital	146,185	127,374
Treasury stock, at cost: 1,643,884 shares in 2005 and 500,000 in 2004	(33,336)	(5,295)
Deferred stock-based compensation	(6,593)	(5,039)
Retained earnings	459,576	364,567
Accumulated other comprehensive income (loss)	(49,480)	2,274
Total stockholders' equity	516,934	484,455
Total Liabilities and Stockholders' Equity	**$ 1,221,346**	**$ 945,460**

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,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
Operating revenues:				
Oil and gas production revenue	$ 203,144	$ 116,514	$ 501,935	$ 324,301
Oil and gas hedge loss	(8,441)	(13,323)	(8,967)	(33,056)
Marketed gas revenue	7,650	3,798	16,597	11,095
Gain on sale of proved properties	246	738	220	2,514
Other revenue	705	351	1,911	1,857
Total operating revenues	203,304	108,078	511,696	306,711
Operating expenses:				
Oil and gas production expense	38,071	24,163	100,418	69,279
Depletion, depreciation, amortization and abandonment liability accretion	36,952	21,470	100,933	62,769
Exploration	10,692	8,871	27,474	20,071
Impairment of proved properties	-	-	-	494
Abandonment and impairment of unproved properties	817	744	4,506	2,632
General and administrative	9,772	5,472	23,239	16,459
Change in Net Profits Interest Plan liability	54,857	7,527	71,253	14,012
Marketed gas operating expense	7,255	3,493	15,607	10,214
Derivative loss (gain)	(60)	(915)	1,310	(46)
Other expense	365	750	1,962	1,860
Total operating expenses	158,721	71,575	346,702	197,744
Income from operations	44,583	36,503	164,994	108,967
Nonoperating income (expense):				
Interest income	83	93	263	479
Interest expense	(2,344)	(1,471)	(6,562)	(4,524)
Income before income taxes	42,322	35,125	158,695	104,922
Income tax expense	(14,988)	(12,560)	(57,997)	(39,072)
Net Income	$ **27,334**	$ **22,565**	$ **100,698**	$ **65,850**
Basic weighted-average common shares outstanding	56,640	57,090	56,941	57,963
Diluted weighted-average common shares outstanding	66,738	66,197	66,847	66,914
Basic net income per common share	**$ 0.48**	**$ 0.40**	**$ 1.77**	**$ 1.14**
Diluted net income per common share	**$ 0.42**	**$ 0.36**	**$ 1.55**	**$ 1.03**

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, 2003	**58,490,246**	**$ 584**	**$146,070**	**(2,005,400)**	**$(16,057)**	**$ -**	**$274,937**	**$ (14,881)**	**$ 390,653**
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	92,479	-	92,479
Change in derivative instrument fair value	-	-	-	-	-	-	-	(14,795)	(14,795)
Reclassification to earnings	-	-	-	-	-	-	-	31,849	31,849
Minimum pension liability adjustment	-	-	-	-	-	-	-	101	101
Total comprehensive income									109,634
Cash dividends declared, $ 0.05 per share	-	-	-	-	-	-	(2,849)	-	(2,849)
Repurchase of common stock from Flying J	-	-	(19,406)	-	-	-	-	-	(19,406)
Treasury stock purchases	-	-	-	(978,600)	(16,336)	-	-	-	(16,336)
Retirement of treasury stock	(2,458,800)	(24)	(26,725)	2,458,800	26,749	-	-	-	-
Issuance of common stock under Employee Stock Purchase Plan	27,748	-	375	-	-	-	-	-	375
Sale of common stock, including income tax benefit of stock option exercises	1,399,052	14	17,832	-	-	-	-	-	17,846
Deferred compensation related to issued restricted stock unit awards, net of forfeitures	-	-	8,122	-	-	(8,122)	-	-	-
Accrued stock-based compensation	-	-	1,106	-	-	-	-	-	1,106
Directors' stock compensation	-	-	-	25,200	349	-	-	-	349
Amortization of deferred stock-based compensation	-	-	-	-	-	3,083	-	-	3,083
Balances, December 31, 2004	**57,458,246**	**$ 574**	**$127,374**	**(500,000)**	**$ (5,295)**	**$ (5,039)**	**$ 364,567**	**$ 2,274**	**$ 484,455**
Comprehensive income, net of tax:									
Net income	-	-	-	-	-	-	100,698	-	100,698
Change in derivative instrument fair value	-	-	-	-	-	-	-	(57,444)	(57,444)
Reclassification to earnings	-	-	-	-	-	-	-	5,690	5,690
Total comprehensive income									48,944
Cash dividends declared, $ 0.10 per share	-	-	-	-	-	-	(5,689)	-	(5,689)
Treasury stock purchases	-	-	-	(1,157,810)	(28,347)	-	-	-	(28,347)
Issuance of common stock under Employee Stock Purchase Plan	14,401	-	255	-	-	-	-	-	255
Sale of common stock, including income tax benefit of stock option exercises	704,892	8	11,937	-	-	-	-	-	11,945
Deferred compensation related to issued restricted stock unit awards, net of forfeitures	-	-	3,579	-	-	(3,579)	-	-	-
Accrued stock-based compensation	-	-	3,040	-	-	-	-	-	3,040
Directors' stock compensation	-	-	-	13,926	306	(306)	-	-	-
Amortization of deferred stock-based compensation	-	-	-	-	-	2,331	-	-	2,331
Balances, September 30, 2005	**58,177,539**	**$ 582**	**$146,185**	**(1,643,884)**	**$(33,336)**	**$ (6,593)**	**$ 459,576**	**$ (49,480)**	**$ 516,934**

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,	
Reconciliation of net income to net cash provided by operating activities:	2005	2004
Net income	$ 100,698	$ 65,850
Adjustments to reconcile net income to net cash provided by operating activities:		
Gain on sale of proved properties	(220)	(2,514)
Depletion, depreciation, amortization and abandonment liability accretion	100,933	62,769
Exploratory dry hole expense	2,514	2,530
Impairment of proved properties	-	494
Abandonment and impairment of unproved properties	4,506	2,632
Unrealized derivative (gain) loss	1,310	(46)
Change in Net Profits Interest Plan liability	71,253	14,012
Deferred and accrued stock-based compensation	5,371	2,965
Income tax benefit from the exercise of stock options	3,991	3,002
Deferred income taxes	12,741	27,205
Other	(38)	(3,498)
Changes in current assets and liabilities:		
Accounts receivable	(31,437)	(26,313)
Prepaid expenses and other	(2,540)	(2,953)
Accounts payable and accrued expenses	33,064	10,997
Net cash provided by operating activities	**302,146**	**157,132**
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	1,211	2,725
Capital expenditures	(204,835)	(127,344)
Acquisition of oil and gas properties, net of cash received	(73,440)	(6,588)
Deposits to short-term investments available-for-sale	(1,502)	(1,470)
Receipts from short-term investments available-for-sale	1,427	12,500
Receipts from restricted cash	-	10,412
Other	3,867	712
Net cash used in investing activities	**(273,272)**	**(109,053)**
Cash flows from financing activities:		
Proceeds from credit facility	234,307	97,497
Repayment of credit facility	(220,000)	(108,500)
Proceeds from sale of common stock for exercise of stock options	8,208	9,957
Repurchase of common stock	(28,347)	(35,743)
Dividends paid	(2,863)	(1,429)
Net cash used in financing activities	**(8,695)**	**(38,218)**
Net change in cash and cash equivalents	20,179	9,861
Cash and cash equivalents at beginning of period	6,418	14,827
Cash and cash equivalents at end of period	**$ 26,597**	**$ 24,688**

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,	
	2005	2004
	(In thousands)	
Cash paid for interest, including amounts capitalized	$ 7,998	$ 8,070
Cash paid for income taxes	$ 36,153	$ 8,800

Dividends of approximately $2.8 million have been declared, but not paid as of September 30, 2005.

As of September 30, 2005 and 2004, $44.5 million and $43.0 million, respectively, are included as additions to oil and gas properties and as increases to 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 2005, May 2004 and January 2004, the Company issued 13,926, 16,800 and 8,400 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 the issuances of $102,500 and $341,000 for the nine-month periods ended September 30, 2005, and 2004, respectively.

In March 2005 and June 2004 the Company issued 194,508 and 465,722 restricted stock units, respectively, pursuant to the Company's restricted stock plan. The total value of the issuances were $4.9 million and $8.3 million, respectively.

In August 2004 the Company exchanged oil and gas properties valued at $1.4 million together with $769,000 of cash for oil and gas properties valued at $2.2 million.

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

September 30, 2005

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 entirely in the continental United States.

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. However, 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 for the year ended December 31, 2004. 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.

Certain amounts in the 2004 unaudited condensed consolidated financial statements have been reclassified to conform to the 2005 unaudited condensed consolidated financial statement presentation. Oil and gas hedge loss has been presented as a separate line item in the accompanying financial statements for all periods presented. As a result, prior period oil and gas production revenues have been reclassified to conform to current presentation. Additionally, common stock and additional paid-in capital amounts have been reclassified for all periods presented to reflect a stock dividend distributed in March 2005.

Stock Dividend

In March 2005 the Company's Board of Directors approved a two-for-one stock split in the form of a stock dividend whereby one additional common share of stock was distributed for each common share outstanding. The stock dividend was distributed on March 31, 2005, to shareholders of record as of the close of business on March 21, 2005. All share and per share amounts for all prior periods presented herein have been restated to reflect this stock split.

Goodwill

Goodwill is measured as the excess of the acquisition costs over the sum of the amounts assigned to the identifiable assets acquired less liabilities assumed. Goodwill was recorded as a result of the acquisition of Agate Petroleum, Inc. in January 2005. Goodwill is reviewed for impairment annually or more frequently if impairment indicators arise.

Suspended Well Costs

As of July 1, 2005, the Company adopted Financial Accounting Standards Board ("FASB") Staff Position FAS 19-1 "Accounting for Suspended Well Costs". Upon adoption of the FASB Staff

Position ("FSP"), the Company evaluated all existing capitalized exploratory well costs under the provisions of the FSP and identified no suspended well costs that should be impaired. As of September 30, 2005, there are no exploratory well costs that have been capitalized for a period greater than one year after the completion of drilling.

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 for the year ended December 31, 2004, 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.

Note 3 – Acquisitions

Agate Acquisition

On January 5, 2005, the Company acquired Agate Petroleum, Inc. ("Agate") in exchange for $40.1 million in cash. The preliminary purchase price has been allocated based on the estimated fair values of the acquired assets and liabilities. The purchase price allocation will not be finalized until all amounts related to receivables and payables are determined with certainty. The Company expects that this allocation will be completed prior to the end of 2005 and will not result in any material adjustments to the preliminary purchase price. The Company acquired $4.6 million in cash from Agate, and the allocation of the purchase price resulted in recording $41.9 million to proved and unproved oil and gas properties, $1.2 million to net current liabilities, $9.8 million to goodwill, a deferred income tax liability of $13.6 million and a $1.4 million asset retirement obligation. The acquisition was accounted for using the purchase method of accounting and was funded with cash on hand and borrowings under the Company's credit facility. Operating results from the acquired properties have been included in the consolidated statements of operations from the date of closing.

The goodwill and deferred income tax liability resulted because present value considerations cannot be applied to the amounts recorded for deferred income taxes from acquiring oil and gas assets in a transaction in which the tax basis of the assets acquired is lower than the book basis fair value. The strategic benefits to the Company that support the recognition of goodwill in this acquisition include the mix of complementary high-quality assets in two of our existing core areas, lower-risk exploitation opportunities, and increased cash flow from operations available for investing activities.

Southern Rockies Acquisition

On August 1, 2005, the Company acquired oil and gas properties primarily in the Wind River and Powder River Basins of Wyoming for $36.9 million in cash. The preliminary purchase price has been allocated based on the fair values of the acquired assets and liabilities as estimated at closing. The allocation of the purchase price resulted in recording $43.7 million to proved and unproved oil and gas properties, a $7.0 million asset retirement obligation, and a net $232,000 to other assets. The purchase price allocation will not be finalized until all post-closing adjustments are determined with certainty. The acquisition was accounted for using the purchase method of accounting and was funded with cash on hand and borrowings under the Company's credit facility. Operating results from the acquired properties have been included in the consolidated statements of operations from the date of closing.

The $7.0 million asset retirement obligation includes approximately $4.7 million related to shut in and temporarily abandoned wells included in the acquisition.

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 common shares outstanding during each period. Vested restricted stock units are included in the calculation of the weighted-average common shares outstanding. The earnings per share calculations reflect the impact of the Company's repurchase of shares of its common stock in 2004 and 2005 (see Note 11-Repurchase of Common Stock).

Diluted net income per common share of stock is calculated by dividing adjusted net income by the weighted-average of common shares outstanding, including the effect of potentially dilutive securities. Adjusted net income is used for the if-converted method and is derived by adding interest expense paid on the Company's 5.75% Senior Convertible Notes due 2022 (the "Convertible Notes") back to net income and then adjusting for nondiscretionary items that are based on income and that would have changed had the Convertible Notes been converted at the beginning of the period. Potentially dilutive securities of the Company consist of in-the-money outstanding options to purchase the Company's common stock, shares into which the Convertible Notes may be converted and unvested restricted stock units.

The shares underlying the grants of restricted stock units are excluded from basic and diluted earnings per share until the measurement date for grants made under the Restricted Stock Plan. Upon measurement, all unvested shares attributable to the restricted stock unit grant are included in the diluted earnings per share calculation. Vested shares are included in both basic and diluted earnings per share.

The dilutive effect of stock options and unvested restricted stock units is considered in the detailed calculation below. There were no anti-dilutive securities related to stock options for the three-month and nine-month periods ended September 30, 2005, or for the three-month period ended September 30, 2004. There were 1,067,532 anti-dilutive securities related to stock options for the nine-month period ended September 30, 2004. There were no anti-dilutive securities related to restricted stock units for any periods presented.

Shares associated with the conversion feature of the Convertible Notes are accounted for using the if-converted method as described above and are considered in the detailed calculation below. A total of 7,692,307 potentially dilutive shares related to the Convertible Notes were included in the calculation of diluted net income per common share for the three-month and nine-month periods ended September 30, 2005, and 2004. The Convertible Notes were issued in March 2002 and can be called in March 2007.

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands, except per share amounts)			
Net income	$ 27,334	$ 22,565	$100,698	$ 65,850
Adjustments to net income for dilution:				
Add: interest expense not incurred if Convertible Notes converted	1,597	1,597	4,740	4,757
Less: other adjustments	(16)	(16)	(47)	(48)
Less: income tax effect of adjustment items	(564)	(565)	(1,715)	(1,754)
Net income adjusted for the effect of dilution	$ 28,351	$ 23,581	$103,676	$ 68,805
Basic weighted-average common shares outstanding	56,640	57,090	56,941	57,963
Add: dilutive effects of stock options and unvested restricted stock units	2,406	1,415	2,214	1,259
Add: dilutive effect of Convertible Notes using if-converted method	7,692	7,692	7,692	7,692
Diluted weighted-average common shares outstanding	66,738	66,197	66,847	66,914
Basic earnings per common share	$ 0.48	$ 0.40	$ 1.77	$ 1.14
Diluted earnings per common share	$ 0.42	$ 0.36	$ 1.55	$ 1.03

Note 5 – Compensation Plans

Restricted Stock Plan

In May 2004 the Restricted Stock Plan was approved by the Company’s stockholders. This established a long-term incentive program whereby grants of restricted stock or restricted stock units (“RSUs”) may be 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 deferral period. The total number of shares of the Company’s common stock reserved for issuance under the Restricted Stock Plan is 11,200,000. This number is reduced to the extent that stock options are granted under the Company’s stock option plans.

St. Mary issued 194,508 RSUs on March 15, 2005, related to 2004 performance. The total expense associated with this issuance was $4.9 million as measured on the issuance date. The total unvested portion of the measured expense was initially recorded as deferred stock-based compensation and is being charged to compensation expense based on the vesting schedule. The granted RSUs vest 25 percent immediately upon issuance and 25 percent on each of the next three anniversary dates of the issuance. The vested shares underlying the RSU grants will be issued on the third anniversary of the issuance, at which time the shares carry no further restrictions. As of September 30, 2005, there were a total of 641,845 RSUs outstanding, of which 276,746 were vested. Total compensation expense related to the RSUs for the three-month and nine-month periods ended September 30, 2005, was $3.0 million and $5.3 million, respectively. These amounts include $2.2 million and $3.0 million of compensation expense for the three-month and nine-month periods ended September 30, 2005, respectively, related to the 2005 plan year for the estimated value of grants expected to be issued in 2006.

Net Profits Interest Plan

Under the Company's Net Profits Interest Plan, oil and gas wells that are completed or acquired during a year are designated within a specific pool. Key employees 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 bonus payments after the Company has received net cash flows returning 100 percent of all costs associated with that pool. Thereafter, 10 percent of future net cash flows generated by the pool are allocated among the participants and 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 Interest Plan at the 10 percent level. The Net Profits Interest Plan has been in place since 1991. Pool years prior to and including 2005 are fully vested. Pool years beginning in 2006 will carry a vesting period of three years and a maximum benefit to participants from a particular year's pool of 300 percent of each participating individual's salary paid to such individual during the year to which the pool relates.

Expense for distributions made or accrued under the Net Profits Interest Plan related to current period operations for the three-month periods ended September 30, 2005, and 2004, were $6.1 million and $2.1 million, respectively, and expense for distributions made or accrued for the nine-month periods ended September 30, 2005, and 2004, were $13.7 million and $5.6 million, respectively. These amounts relate to the current period realized results from oil and gas operations for the properties associated with the respective pools that have achieved repayment of their costs and expenses.

In a separate calculation, the Company records the estimated liability for future payments under the Net Profits Interest Plan based on the discounted value of estimated future payments associated with each individual pool. The calculation of this liability is a management estimate utilizing a discount rate of predominately 15 percent, and is intended to represent the best estimate of the present value of expected future payments under the Net Profits Interest Plan. The Company's estimate of its liability is highly dependent on the price assumptions used in the calculation. The price assumptions are currently formulated by applying a price that is derived from a rolling average of actual prices realized from the prior 24 months together with adjusted NYMEX strip prices for the ensuing 12 months. This calculation is supplemented with actual hedge prices for the percentage of forecast production hedged. The forecast expense associated with this significant management estimate has increased substantially as a result of the significant increase of oil and gas prices in 2005 together with the impact of pricing that is assured to the Company as a result of executing its expanded hedging strategy. The Company continually evaluates the assumptions used in this calculation in order to include the current market environment for oil and gas prices, discount rates and overall market conditions. Sensitivity information related to this liability is presented in the Management's Discussion and Analysis of Financial Condition and Results of Operations under the caption *Hedging Activities and our Net Profits Interest Plan.* Actual cash payments to be made in future periods are dependent on realized actual production, prices, and costs associated with the individual pools of the Net Profits Interest Plan. Consequently, actual cash payments will be inherently different from the amounts estimated.

The following table presents the changes in the estimated future liability attributable to the Net Profits Interest Plan:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)		(In thousands)	
Liability balance for Net Profits Interest Plan as of the beginning of the period	$ 46,957	$ 12,648	$ 30,561	$ 6,163
Increase in liability	60,988	9,669	84,952	19,610
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(6,131)	(2,142)	(13,699)	(5,598)
Liability balance for Net Profits Interest Plan as of the end of the period	$101,814	$ 20,175	$101,814	$ 20,175

The Company records changes in the present value of estimated future payments under the Net Profits Interest Plan as a separate item in the consolidated statements of operations. The change in the estimated liability is recorded as an increase or decrease to expense in the current period. The amount recorded as an increase or decrease to expense associated with the change in the estimated liability is not allocated to general and administrative costs or exploration costs because it is an estimate at the current time of the adjustment to the liability that 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,	
	2005	2004	2005	2004
	(In thousands)		(In thousands)	
General and administrative expense	$ 26,758	$ 4,565	$ 34,889	$ 8,193
Exploration expense	28,099	2,962	36,364	5,819
Total	$ 54,857	$ 7,527	$ 71,253	$ 14,012

Stock Option Plans

Statement of Financial Accounting Standards ("SFAS") No. 123, "Accounting for Stock-Based Compensation," establishes a fair value method of accounting for stock-based compensation through either recognition or disclosure. The Company accounts for stock-based compensation using the intrinsic value recognition and measurement principles prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB No. 25"), and has elected to adopt SFAS No. 123 through compliance with the disclosure requirements set forth in the Statement. Because the exercise price of the Company's stock options equals the market price of the underlying common stock on the date of grant, no compensation expense is recognized under APB No. 25. The following table illustrates the pro forma effect on net income and earnings per share if the Company had applied the fair value recognition provisions of SFAS No. 123 to stock-based employee compensation for the periods presented.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands, except per share amounts)			
Net income -				
As reported	$ 27,334	$ 22,565	$ 100,698	$ 65,850
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	1,925	556	3,344	1,861
Less: Stock-based employee compensation expense determined under fair value based method for all awards, net of related income tax effects	(2,546)	(1,421)	(5,123)	(4,471)
Pro forma net income	$ 26,713	$ 21,700	$ 98,919	$ 63,240
Basic earnings per share -				
As reported	$ 0.48	$ 0.40	$ 1.77	$ 1.14
Pro forma	$ 0.47	$ 0.38	$ 1.74	$ 1.09
Diluted earnings per share -				
As reported	$ 0.42	$ 0.36	$ 1.55	$ 1.03
Pro forma	$ 0.41	$ 0.34	$ 1.52	$ 0.99

For purposes of these pro forma disclosures, the estimated fair values of the options are amortized to expense over the options' vesting periods. The effects of applying SFAS No. 123 in the pro forma disclosure are not necessarily indicative of actual future amounts.

The fair value of options and employee stock purchases has been measured at the date of grant using the Black-Scholes option-pricing model. The fair value of these awards granted in the three-month and nine-month period ended September 30, 2005, and 2004, was estimated using the weighted-average assumptions in the following table. No options were granted during the nine-month period ended September 30, 2005.

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
Risk free interest rate				
Stock options	*	*	*	3.6%
Employee Stock Purchase Plan	**	**	2.1%	3.6%
Dividend yield				
Stock options	*	*	*	0.3%
Employee Stock Purchase Plan	**	**	0.5%	0.3%
Volatility factor of the expected market price of the Company's stock				
Stock options	*	*	*	38.5%
Employee Stock Purchase Plan	**	**	40.5%	22.8%
Expected life of the options (in years)				
Stock options	*	*	*	7.6
Employee Stock Purchase Plan	**	**	0.5	0.5

* No options were granted under the Stock Option Plan in the first three quarters of fiscal year 2005 or in the second or third quarter of fiscal year 2004.

** No shares were issued under the ESPP in the third quarter of fiscal years 2005 and 2004.

The Black-Scholes option valuation model was developed for use in estimating the fair value of traded options that have no vesting restrictions and are fully transferable. In addition, option valuation models require the input of highly subjective assumptions including the expected stock price volatility. The Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, it is management's opinion that the valuations afforded by the existing models are different from the value that the options would realize if traded in the market.

In December 2004 the FASB issued SFAS No. 123 (Revised 2004), "Shared-Based Payment" ("SFAS No. 123R"). This statement provides for the accounting for transactions in which an entity exchanges equity instruments or incurs liabilities in exchange for goods or services. The effective date of this Statement was delayed by the Securities and Exchange Commission, and the Company will be required to adopt SFAS No. 123R on January 1, 2006. Under the modified-prospective method, the Company estimates that it will record a total of $2.8 million of compensation expense in periods following the implementation date related to the unvested portion of its stock options issued prior to the effective date. There will be no cumulative effect of change in accounting principle as a result of the adoption of SFAS No. 123R. Recorded compensation expense and pro-forma compensation expense related to stock-based compensation that is subject to accelerated vesting upon retirement are currently recognized over the vesting periods of the awards and are accelerated only upon retirement. Upon adoption of SFAS No. 123R, compensation expense related to accelerated vesting for awards issued on or after January 1, 2006, will be recognized over the period from the issuance of the award through the date on which the employee becomes eligible to retire. If the Company had applied this new cost recognition method since the inception of its share-based payment plans, there would have been no material effect on the Company's financial statements or pro forma disclosures for any periods presented herein.

Note 6 - Income Taxes

Income tax expense for the three-month and nine-month periods ended September 30, 2005, and 2004, differs from the amounts 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 allowed in the American Jobs Creation Act of 2004 and other permanent differences.

For the three-month and nine-month periods ended September 30, 2005, the Company’s current portion of income tax expense was $23.6 million and $48.5 million, respectively, compared to $2.1 million and $15.5 million, respectively, for the three-month and nine-month periods ended September 30, 2004. The Company’s effective tax rates for the three-month and nine-month periods ended September 30, 2005, were 35.4 percent and 36.5 percent, respectively, compared to 35.8 percent and 37.2 percent, respectively, for the three-month and nine-month periods ended September 30, 2004. The decrease in tax rate reflects a change in the composition of the estimated highest marginal state tax rate as a result of acquisition and drilling activity. It also reflects the Company’s estimate of the effect of the domestic production activities deduction and the possible impact of state tax permanent differences.

Note 7 - Long-term Debt

Revolving Credit Facility

The Company executed an Amended and Restated Credit Agreement on April 7, 2005, to replace its previous credit facility. The new 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 certain 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 is currently $500 million, 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 $200 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 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%	0.250%	0.250%	0.500%
Commitment fee rate	0.250%	0.300%	0.375%	0.375%

At September 30, 2005, the Company’s borrowing base utilization percentage, as defined under the credit agreement, was 26 percent. The Company had $47 million in Euro-dollar loans and $5 million in ABR loans outstanding under its revolving credit facility as of September 30, 2005.

5.75% Senior Convertible Notes Due 2022

As of September 30, 2005, the Company also had $100 million in outstanding borrowings under the Convertible Notes. The Convertible Notes provide for the payment of contingent interest of up to an additional 0.5 percent during six-month interest periods based on the note trading price before the beginning of the particular six-month period. Under that provision, interest was accrued at a total rate of 6.25 percent for the three-month and nine-month periods ended September 30, 2005, and 2004. Based on the trading price of the Convertible Notes over the determination period, the Company will be subject to the contingent interest payments for the period from September 15, 2005, to March 14, 2006.

Weighted-average Interest Rate Paid

The weighted-average interest rates paid for the third quarters of 2005 and 2004 were 7.2 percent and 6.2 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 and the effects of interest rate swaps. The weighted-average interest rates paid for the nine-month periods ended September 30, 2005, and 2004, were 7.1 percent and 6.6 percent, respectively. The Company capitalized interest costs of $516,000 and $1.4 million for the three-month and nine-month periods ended September 30, 2005, respectively, and capitalized interest costs of $322,000 and $921,000 for the three-month and nine-month periods ended September 30, 2004, respectively.

Note 8 – Derivative Financial Instruments

The Company recognized a net loss of $10.5 million from its derivative contracts for the nine months ended September 30, 2005, compared to a net loss of $32.2 million for the same period in 2004. Comparative amounts for the three-month periods ended September 30, 2005, and 2004, were net losses of $8.7 million and $12.1 million, respectively.

The following table summarizes all derivative instrument gain (loss) activity for the periods presented (in thousands):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)		(In thousands)	
Derivative contract settlements included in oil and gas hedge loss	$ (8,441)	$ (13,323)	$ (8,967)	$ (33,056)
Ineffective portion of hedges qualifying for hedge accounting included in derivative gain (loss)	(306)	33	(1,328)	47
Non-qualified derivative contracts included in derivative gain (loss)	365	882	17	(1)
Interest rate derivative contract settlements	(275)	311	(247)	795
Total	$ (8,657)	$ (12,097)	$ (10,525)	$ (32,215)

Oil and Gas Commodity Hedges

To mitigate a portion of the exposure to adverse market changes, the Company has entered into various derivative contracts. The Company has in place derivative contracts, which included swap and collar arrangements at September 30, 2005, for the sale of oil and natural gas. Please refer to the tables under *Summary of Oil and Gas Production Hedges in Place* in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations for details regarding the Company's hedged volumes and associated prices. Including oil and natural gas collar arrangements entered into subsequent to September 30, 2005, the Company has hedge contracts through 2011 for a total of approximately 10.6 million Bbls and 70.5 million MMBTU of anticipated production. 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 Company attempts to qualify its oil and natural gas derivative instruments as cash flow hedges for accounting purposes. At September 30, 2005, all oil and natural gas derivative instruments qualified as cash flow hedges for accounting purposes. The estimated fair value of oil and natural gas derivative contracts designated and qualifying as cash flow hedges under SFAS No. 133 was a net liability of $80.6 million at September 30, 2005. If prices remain unchanged from quarter-end levels, the Company would reclassify this amount to oil and gas hedge loss included in operating revenue as the hedged production quantity is produced.

Gains or losses from the settlement of oil and gas derivative contracts are reported in the total operating revenues section on 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 derivative gain (loss) in the consolidated statement of operations.

Derivative gain (loss) for the nine months ended September 30, 2005, and 2004, includes a net loss of $1.3 million and a net gain of $47,000, respectively, from ineffectiveness related to oil and natural gas derivative contracts. Comparative amounts for the three-month periods ended September 30, 2005, and 2004, were a net loss of $306,000 and a net gain of $33,000, respectively.

As of September 30, 2005, the amount of unrealized loss net of deferred income taxes to be reclassified from accumulated other comprehensive income to oil and gas production operating revenues in the next twelve months was $41.3 million.

Interest Rate Derivative Contracts

In October 2003 the Company entered into fixed-to-floating interest rate swaps for a total notional amount of $50 million through March 20, 2007. Under the swaps, St. Mary will be paid a fixed interest rate of 5.75 percent and will pay a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date. The payment dates of the swaps match exactly with the interest payment dates of the Convertible Notes.

The Company entered into a floating-to-fixed interest rate swap on April 13, 2005, for a total notional amount of $50 million through March 20, 2007, that effectively offsets the fixed-to-floating interest rate swaps described above. Under the swap, St. Mary will be paid a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date and will pay a fixed interest rate of 6.85 percent. The payment dates of the swap match exactly with the interest payment dates of the Convertible Notes and the fixed-to-floating interest rate swaps. The impact of this instrument, when combined with the other interest rate swaps, is that the Company has fixed its net liability related to the interest rate swaps and will pay a 1.1 percent interest factor on $50 million of notional debt through March 2007.

During the nine-month period ended September 30, 2005, the Company made payments of $247,000, and during the nine-month period ended September 30, 2004, the Company received payments of $795,000 under the swap arrangements. These payments are included in the Company's interest expense.

The fair value of the interest rate derivatives was a liability of $776,000 as of September 30, 2005. The Company recorded net derivative losses in the consolidated statements of operations of $344,000 for the nine-month period ended September 30, 2005, and $58,000 for the nine-month period ended September 30, 2004, from mark-to-market adjustments for these derivatives. Comparative amounts for the three-month periods ended September 30, 2005, and 2004, were a net gain of $132,000 and net gain of $731,000, respectively. The six-month LIBOR rate on September 30, 2005, was 4.23 percent.

These swaps do not qualify for fair value hedge treatment under SFAS No. 133 and related pronouncements.

Convertible Note Derivative Instrument

The contingent interest provision of the Convertible Notes is considered an embedded equity-related derivative that is not clearly and closely related to the fair value of an equity interest and therefore must be separately accounted for as a derivative instrument. The value of the derivative at issuance of the Convertible Notes in March 2002 was $474,000. This amount was recorded as a decrease to the Convertible Notes payable in the consolidated balance sheets. Interest expense for each of the nine-month periods ended September 30, 2005, and 2004, includes $71,000 of amortization of this derivative. Interest expense for each of the three-month periods ended September 30, 2005, and 2004, includes $24,000 of amortization. Derivative gain (loss) in the consolidated statements of operations for the nine-month periods ended September 30, 2005, and 2004, includes net gains of $361,000 and $57,000, respectively, from mark-to-market adjustments for this derivative. Comparative amounts for the three-month periods ended September 30, 2005, and 2004, includes net gains of $233,000 and $151,000, respectively. The fair value of this derivative was a liability of $459,000 at September 30, 2005.

Note 9 – Pension Benefits

The Company's employees participate in 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 "Nonqualified Pension Plan").

Components of Net Periodic Benefit Cost

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

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2005	2004	2005	2004
	(In thousands)		(In thousands)	
Service cost	$ 346	$ 285	$ 1,039	$ 854
Interest cost	134	122	401	367
Expected return on plan assets	(94)	(74)	(283)	(221)
Amortization of prior service cost	-	(4)	-	(12)
Amortization of net actuarial loss	60	55	181	163
Net periodic benefit cost	$ 446	$ 384	$ 1,338	$ 1,151

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 10 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

St. Mary contributed $1.1 million to the Qualified Pension Plan during the second quarter of 2005. No further contributions are planned for the remainder of 2005.

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 accretion expense in connection with the discounted liability over the remaining estimated economic lives of the respective oil and gas properties.

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,	
	2005	2004	2005	2004
	(In thousands)		(In thousands)	
Beginning asset retirement obligation	$ 44,383	$ 26,868	$ 40,911	$ 25,485
Liabilities incurred	8,813	612	11,212	1,280
Liabilities settled	(499)	(137)	(858)	(364)
Accretion expense	850	492	2,282	1,434
Ending asset retirement obligation	$ 53,547	$ 27,835	$ 53,547	$ 27,835

Note 11 – Repurchase of Common Stock

Stock Repurchase Program

In August 2004 the Company's Board of Directors approved an increase in the number of shares that may be repurchased under the original authorization approved in August 1998 to 6,000,000 as of the effective date of the resolution. 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 credit facility agreement and compliance with securities laws. Stock repurchases may be funded with existing cash balances, internal cash flow and borrowings under the credit facility.

During the first nine months of 2005, the Company repurchased a total of 1,157,810 shares of its common stock under the program at a weighted-average price of $24.48 per share including the effect of commissions. No shares were repurchased under the program during the third quarter of 2005.

As of September 30, 2005, the Company had authorization to repurchase 3,863,590 shares that remain from this authorization. Subsequent to September 30, 2005, the Company repurchased 17,472 shares of its common stock under the program at a weighted-average price of $31.72 per share, including the effect of commissions.

Repurchase of Common Stock from Flying J

On February 9, 2004, the Company repurchased 6,671,636 restricted shares of its common stock from Flying J Oil & Gas Inc. and Big West Oil & Gas Inc. (collectively “Flying J”) for a total of $91.0 million. St. Mary originally issued these shares to Flying J on January 29, 2003, in connection with St. Mary's acquisition of certain oil and gas properties. In addition to issuing the shares in the acquisition, St. Mary loaned Flying J $71.6 million. Flying J used the proceeds of the stock repurchase to repay their outstanding loan balance of $71.6 million. Accrued interest, which had not been recorded by the Company for financial reporting purposes due to the non-recourse nature of the loan, was forgiven. The net $19.4 million cash outlay for the repurchase was funded from the Company's existing cash balances and borrowings under its bank credit facility.

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

This discussion contains forward-looking statements. Please refer to the Cautionary Statement 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 our revenues and generate our cash flows from operations primarily from sales at the wellhead of produced natural gas and crude oil. Our oil and gas reserves and operations are concentrated in the Anadarko, Arkoma, Permian, and various Rocky Mountain basins together with the ArkLaTex region and the onshore Gulf Coast and the offshore Gulf of Mexico. We maintain a balanced portfolio of proved reserves, development drilling opportunities and resource plays.

Stock Dividend

In March 2005 the Board of Directors approved a two-for-one stock split in the form of a stock dividend whereby one additional common share of stock was distributed for each common share outstanding. The stock dividend was distributed on March 31, 2005, to shareholders of record as of the close of business on March 21, 2005. All share and per share amounts for all prior periods presented within this report have been restated to reflect this stock split.

Effects of Hurricanes Katrina and Rita

During 2005, approximately 17 percent of our production has come from areas affected by Hurricanes Katrina and Rita, including our Gulf Coast region and our properties in southern Texas. The overall impact from the recent hurricanes in the Gulf of Mexico did not have a material adverse effect on our financial position or results of operations. However, we did sustain some damage, and production was shut in during the third quarter. Production from certain properties continues to be shut-in as of the date of this report.

Our production platform at Vermilion Block 273 was lost. Our net production from Vermillion Block 273 was approximately 829 MCFED, and we had an estimated 492 MMCF of proved reserves prior to the hurricanes. We are still evaluating the economics of replacing this platform. We have inspected all operated properties. The hurricane related damage to our operated wells, an additional platform and other facilities has for the most part been addressed, and we have restored production and drilling operations, as applicable, to these affected properties. We maintain insurance that we expect to utilize with regard to the lost platform and to make necessary repairs to existing and drilling wells.

Damage to St. Mary's properties and to third-party pipelines and processing facilities caused by the hurricanes required that we shut in approximately 400 MMCFE of production during the third quarter of 2005. Approximately seven MMCFED of production remained shut in as of October 28, 2005, and we anticipate a total of approximately 700 MMCFE to be shut in during the fourth quarter of 2005. Restoration of the remaining shut in production is largely dependent on repairs to transportation and processing facilities which are owned and operated by other operators and facility owners.

Potential revenue impacts caused by shut-in production from the hurricanes were offset by a sudden and significant increase in oil and gas prices caused by hurricane-related supply disruptions for both crude oil and natural gas. We benefited from higher prices we received for production in other areas of the country during the month of September. The operations analysis elsewhere in this discussion reflects higher prices for the quarter ended September 30, 2005, resulting in part from impacts of the hurricanes.

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. As 2005 progresses we continue to benefit from high oil and gas prices that are major contributing factors to the record financial results we are reporting. Higher natural gas prices are believed to be the result of tightening supply coupled with increasing demand in the United States. Finite storage capacity, changes in production, import capacity, oil price volatility, hurricanes, and other weather-related effects on domestic demand have impacted natural gas price volatility. Higher oil prices reflect decreases in worldwide excess production capacity, constrained refinery capacity, continuing increases in demand from the global economy, the impact of weather on both supply and demand, and continued instability in the Middle East.

Hedging Activities and our Net Profits Interest Plan

Subsequent to September 30, 2005, we hedged a significant portion of anticipated future production from our currently producing properties using zero cost collars. These contracts supplement our previous swap and collar contracts. Considering all oil and gas production hedge contracts in place as of October 28, 2005, we have hedged approximately 10.6 million Bbls and 70.5 million MMBTU of our anticipated production through the year 2011. We believe we have established an economic base for our future operations and will still participate in higher prices in the event they should occur because of the spread between the floor and ceiling prices of these collars. 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.

The execution of our revised hedging strategy, together with significant movement in oil and gas prices in the third quarter of 2005, resulted in a significant increase in the estimated future liability associated with our Net Profits Interest Plan. The non-cash expense associated with this estimated liability increased substantially in the quarter ended September 30, 2005. We recorded expense of $54.9 million for this quarter compared to $12.2 million for the previous quarter ended June 30, 2005 and $7.5 million for the prior year quarter ended September 30, 2004.

The calculation of this liability represents management's best estimate of future amounts payable from the Net Profits Interest Plan. We calculate separate monthly estimates of the payments to be made for the life of each individual pool under the Net Profits Interest Plan. In most cases these calculations will span more than 20 years. We use predominantly a 15 percent discount rate to calculate the present value of these future payments, and the resulting amount is recorded as our liability. Prices impact the calculated cash flows during periods after payout and they can dramatically affect the timing of the estimated date of payout of the individual pools. Our price assumptions are currently determined from a rolling average of actual prices received for the preceding 24 months combined with adjusted NYMEX strip prices for the next 12 months. This average is supplemented by hedge prices for the percentage of forecast production hedged. The calculation of the estimated liability for the Net Profits Interest Plan is sensitive to our price estimates and discount rate assumptions. For example, if we changed the prices in our calculation by 10 percent, the liability recorded at September 30, 2005, would differ by approximately $19.0 million, and a one percent change in the discount rate would result in a change of approximately $4.5 million. We continually evaluate the assumptions used in our calculations to ensure we consider possible effects from the current market environment for oil and gas prices, discount rates and overall market conditions.

As a result of higher prices received over the last 12 months, the actual cash payments we will make for production from the quarter ended September 30, 2005, will also be higher than cash payments made on production from the quarter ended September 30, 2004. Actual cash payments to be made in future quarters are dependent on realized actual production, prices and costs associated with the individual pools within the Net Profits Interest Plan. 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.

Third Quarter 2005 Highlights

NYMEX prices for the third quarter of 2005 averaged $8.25 per MMBtu of gas and $63.19 per barrel of oil, an increase of 21 percent for gas and an increase of 19 percent for oil compared to the second quarter of 2005. These prices were 41 percent higher for gas and 44 percent higher for oil compared to the comparable period a year ago.

We acquired oil and gas properties on August 1, 2005, for $36.9 million in cash, after customary closing adjustments. The effective date of the acquisition was May 1, 2005. We acquired an estimated 22.5 BCFE of proved reserves, 72 percent of which were developed. The properties acquired are located primarily in the Wind River and Powder River Basins of Wyoming. This acquisition was funded using cash on hand and funds available under our existing credit facility.

The results for the quarter ended September 30, 2005, reflect record quarterly production and record oil and gas revenues, which have resulted in record net cash provided by operating activities. The production results reflect our fifth consecutive quarter of production growth. As a result of shut-in production resulting from Hurricanes Katrina and Rita, we anticipate a slight decrease in production in the fourth quarter of 2005 compared to the third quarter of 2005.

Our net income for the quarter ended September 30, 2005, was $27.3 million or $0.42 per diluted share compared to 2004 results of $22.6 million or $0.36 per diluted share. Non-cash expense related to the change in the Net Profits Interest Plan liability increased by $47.3 million to $54.9 million. Net cash provided by operating activities was $116.6 million, up 103 percent from $57.3 million provided in the third quarter of 2004. Production increased 22 percent to 23.1 BCFE, and our average realized price increased 55 percent to $8.43 per MCFE and reflects a $4.9 million decrease in oil and gas hedge loss between the two periods. Unit costs increased for the period as lease operating and transportation expense increased $0.19 to $1.07 per MCFE, production taxes increased $0.19 to $0.58 per MCFE, and DD&A increased $0.47 to $1.60 per MCFE. We discuss these financial results and trends in more detail below.

The table below provides information regarding selected production and financial information for the quarter ended September 30, 2005, and the immediately preceding three quarters ended June 30, 2005, March 31, 2005, and December 31, 2004.

	For the Three Months Ended			
	September 30, 2005	June 30, 2005	March 31, 2005	December 31, 2004
	(In millions)			
Production (MCFE)	23.1	21.8	20.6	19.9
Oil and gas production revenues	$ 203.1	$ 160.4	$ 138.4	$ 139.3
Lease operating and transportation expense	$ 24.7	$ 21.0	$ 22.2	$ 17.8
Production taxes	$ 13.4	$ 9.2	$ 10.0	$ 8.4
General and administrative expense	$ 9.8	$ 7.5	$ 6.0	$ 5.5
Net income	$ 27.3	$ 38.3	$ 35.1	$ 26.6
Percentage change from previous quarter:				
Production (MCFE)	6%	6%	4%	
Oil and gas production revenues	27%	16%	(1)%	
Lease operating and transportation expense	18%	(5)%	25%	
Production taxes	46%	(8)%	19%	
General and administrative expense	31%	25%	9%	
Net income	(29)%	9%	32%	

First Nine Months 2005 Highlights

NYMEX prices for the first nine months of 2005 averaged $7.12 per MMBtu of gas and $55.40 per barrel of oil, an increase of 22 percent for gas and an increase of 42 percent for oil compared to the same period of 2004. As of September 30, 2005, the NYMEX strip prices for the remainder of the year were $13.78 per MMBtu and $66.40 per barrel compared to September 30, 2004, NYMEX strip prices of $6.89 per MMBtu and $45.24 per barrel.

In January 2005 we closed the acquisition of Agate Petroleum Inc. for $40.1 million in cash. Based on the preliminary purchase price allocation, we acquired $4.6 million in cash, and recorded approximately $41.9 million to oil and gas properties, $9.8 million to goodwill, $1.2 million to net current liabilities, $13.6 million of deferred income tax liability and a $1.4 million asset retirement obligation.

During the second quarter of 2005 we purchased 1,157,810 shares of our common stock at an average cost of $24.48 per share, including the effect of commissions. We have 3,863,590 shares available for repurchase out of the 6,000,000 shares authorized under the repurchase program as of September 30, 2005.

On April 7, 2005, we closed a new five-year, $500 million credit facility agreement with Wachovia Bank, Wells Fargo Bank and eight other participating banks. The current borrowing base is $500 million, and we have elected a commitment of $200 million. Additional details regarding this facility are included below under the caption, Overview of Liquidity and Capital Resources.

Net income for the nine months ended September 30, 2005, was a record $100.7 million or $1.55 per diluted share compared to the 2004 results of $65.9 million or $1.03 per diluted share. Non-cash expense related to the change in the Net Profits Interest Plan liability increased $57.2 million to $71.3 million. Net cash provided by operating activities was a record $302.1 million, up 92 percent from 157.1 million provided in 2004. Production increased 18 percent to another record of 65.5 BCFE. Our average realized price for the period ending September 30, 2005, increased 43 percent to $7.53 per MCFE from $5.25 per MCFE reported at September 30, 2004, and reflects a $24.1 million decrease in oil and gas hedge loss between the two periods. We are also experiencing record high production unit costs. Total production unit costs increased $0.27 to $1.53 per MCFE. DD&A unit costs increased $0.41 to $1.54 per MCFE. General and administrative expense increased $0.05 to $0.35 per MCFE. These financial results and trends are discussed in more detail below.

Outlook for the Remainder of 2005

Over the remainder of 2005 we will continue to execute our business plan, including the following:

- Our capital expenditures forecast for drilling is $322 million this year. A table of expected budget amounts by core area is detailed under the caption *Capital Expenditure Forecast*. In addition we have spent approximately $87 million on acquisitions this year. We do not have any specific acquisition targets identified that are likely to close before the end of the year. We continue to maintain a disciplined approach to acquisitions as we actively evaluate acquisition opportunities.

- Our Hanging Woman Basin coalbed methane project is in full development. In the first nine months of 2005 we have completed 64 wells. As of October 28, 2005, we are completing an additional 30 wells, are drilling three more wells, and have 71 locations that have been permitted. We plan to complete at least 147 wells for the year. Production for the project continues to be ahead of forecast amounts and was 2,950 MCFED from 121 producing wells as of October 28, 2005.

- By the end of the year we expect to have participated in the drilling of 47 wells in the Williston Basin Middle Bakken Play during 2005. We currently have two operated drilling rigs and one operated re-entry rig in the play.

- We tentatively plan to drill a total of 11 horizontal wells in the Centrahoma field during 2005. We have successfully completed vertical producing wells to the Cromwell formation in 11 sections in this field, and we hold 36,000 gross and 20,000 net contiguous acres in the area. Approximately half of that acreage is held by existing production. In 2005 we have drilled horizontal wells into two producing zones and are drilling into a third. The Mowdy #1 well was completed in March with an initial rate of 3,000 MCFE per day and is expected to recover reserves in excess of two BCFE. We are currently completing two additional horizontal wells in the Cromwell formation. In the third quarter we completed our first horizontal well in the Woodford shale formation. The Ann Bey 2-7 produced at an initial rate of 1,400 MCFE per day before stabilizing at approximately 640 MCFE per day. We are currently drilling our first horizontal test well in the Wapanuka limestone formation. Our future development plans could ultimately result in drilling approximately four horizontal wells per section in each of the three producing formations in the field.

- We anticipate that production for 2005 will be between 87 BCFE and 88 BCFE, which exceeds 2004 reported production of 75.4 BCFE. This increase is a result of acquisitions and success in our drilling programs.

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

Selected Operations Data (In thousands, except price and per MCFE amount)

	For the Three Months Ended September 30, 2005	For the Three Months Ended September 30, 2004	% of Change Between Periods	For the Nine Months Ended September 30, 2005	For the Nine Months Ended September 30, 2004	% of Change Between Periods
Net production volumes						
Natural gas (Mcf)	13,894	11,531	20%	39,125	34,214	14%
Oil (Bbl)	1,534	1,245	23%	4,396	3,547	24%
MCFE (6:1)	23,100	19,000	22%	65,502	55,494	18%
Average daily production						
Natural gas (MMcf per day)	151	125	20%	143	125	15%
Oil (MBbl per day)	17	14	23%	16	13	24%
MMCFE per day (6:1)	251	207	22%	240	203	18%
Oil & gas production (1) revenues(1)						
Gas production revenue	$ 108,847	$ 61,031	78%	$ 272,958	$ 181,172	51%
Oil production revenue	85,856	42,160	104%	220,010	110,073	100%
Total	$ 194,703	$ 103,191	89%	$ 492,968	$ 291,245	69%
Oil & gas production expense						
Lease operating expenses	$ 22,915	$ 14,663	56%	$ 62,313	$ 45,291	38%
Transportation costs	1,758	2,022	(13)%	5,451	5,388	1%
Production taxes	13,398	7,478	79%	32,654	18,600	76%
Total	$ 38,071	$ 24,163	58%	$ 100,418	$ 69,279	45%
Average realized sales price(1)						
Natural gas (per Mcf)	$ 7.83	$ 5.29	48%	$ 6.98	$ 5.30	32%
Oil (per Bbl)	$ 55.95	$ 33.87	65%	$ 50.05	$ 31.04	61%
Per MCFE Data:						
Average net realized price(1)	$ 8.43	$ 5.43	55%	$ 7.53	$ 5.25	43%
Lease operating expense	(0.99)	(0.77)	29%	(0.95)	(0.82)	16%
Transportation costs	(0.08)	(0.11)	(27)%	(0.08)	(0.10)	(20)%
Production taxes	(0.58)	(0.39)	49%	(0.50)	(0.34)	47%
General and administrative	(0.42)	(0.29)	45%	(0.35)	(0.30)	17%
Operating profit	$ 6.36	$ 3.87	64%	$ 5.65	$ 3.69	53%
Depletion, depreciation and amortization	$ 1.60	$ 1.13	42%	$ 1.54	$ 1.13	36%

(1) Includes the effects of our hedging activities

Financial Information (In thousands, except per share amounts):

	September 30, 2005	December 31, 2004	% of Change Between Periods
Working capital (deficit)	$ (23,820)	$ 12,035	(298)%
Long-term debt	$ 151,862	$ 136,791	11%
Stockholders' equity	$ 516,934	$ 484,455	7%

	For the Three Months Ended September 30,		% of Change Between Periods	For the Nine Months Ended September 30,		% of Change Between Periods
	2005	2004		2005	2004	
Basic net income per common share	$ 0.48	$ 0.40	20%	$ 1.77	$ 1.14	55%
Diluted net income per common share	$ 0.42	$ 0.36	17%	$ 1.55	$ 1.03	50%
Basic weighted-average shares outstanding	56,640	57,090	(1)%	56,941	57,963	(2)%
Diluted weighted-average shares outstanding	66,738	66,197	1%	66,847	66,914	0%

The preceding table is presented as a summary of information relating to those key indicators of financial condition and operating performance that we believe to be most important. We present per MCFE information since we use this information to evaluate our performance relative to our peers and to measure trends that we believe require analysis. Our period-to-period comparison of financial results presented later provides additional details for the per MCFE differences between reported periods.

We expect oil and gas production expenses for the remainder of 2005 will be higher in the fourth quarter. Production taxes will be higher on a per MCFE basis in the remainder of 2005 as a result of the increase in oil and gas pricing that we are experiencing. Lease operating expense will be impacted by competition for scarce resources in the oil and gas service sector. Depreciation, depletion and amortization will increase due to the higher costs associated with finding and acquiring crude oil and natural gas. We expect general and administrative expense per MCFE will continue to increase through 2005 primarily as a result of our incentive compensation plans and increased charitable contributions.

The remaining information in the table relates to information we have provided in 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 plans for the foreseeable future.

Sources of Cash

Our primary sources of liquidity are the cash provided by operating activities and debt financing. We believe that we can access capital markets if needed, although we have no current plans to do so.

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 of $500 million, and we have elected a commitment amount of $200 million, which results in lower commitment fees payable to the bank syndicate. 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. 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 of Part I, Item 1 of this report. Borrowings under the new facility are secured by the majority of our oil and gas properties and 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. Our loan balance of $52 million on September 30, 2005, was comprised of $47 million of Euro-dollar based borrowing and $5 million of ABR borrowing. As of October 28, 2005, our total outstanding borrowings under the credit facility had been reduced to $15 million of Euro-dollar based borrowings, and we had one letter of credit outstanding for $1.2 million.

We increased our net borrowings by $15 million to $52 million in the first nine months of 2005 primarily to fund our acquisitions of Agate Petroleum and oil and gas properties in Wyoming, to expand our drilling program, and to repurchase shares of our common stock. Our weighted-average interest rate paid in the first nine months of 2005 was 7.1 percent and included fees paid on the unused portion of the credit facility aggregate commitment amount, amortization of deferred financing costs, amortization of the contingent interest embedded derivative associated with the convertible notes, and the effects of interest rate swaps.

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, income taxes, common stock repurchases and stockholder dividends. In the first nine months of 2005 we spent $278.3 million on capital development and $28.3 million to acquire shares of our common stock using cash flows from operations and borrowings under our credit facility. We also made cash payments for income taxes of $36.2 million. We estimate that approximately 80 to 85 percent of our total income tax liability for 2005 will result in cash taxes that are payable on a current basis.

As of September 30, 2005, we have Board authorization to repurchase up to an additional 3,863,590 shares of our common stock under our stock repurchase program. These 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 and compliance with securities laws. Subsequent to September 30, 2005, the Company repurchased 17,472 shares of common stock under the program at a weighted average price of $31.72 per share, including the effect of commissions.

In connection with our two-for-one stock split in March 2005, we announced that the semi-annual dividend rate would remain at $0.05 per share. This effectively doubles our annual cash dividend payments from 2004. On September 27, 2005, we declared our semi-annual dividend of $0.05 per share payable on November 14, 2005, to shareholders of record as of the close of business November 4, 2005. We have sufficient liquidity to make this payment. 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, in thousands, and percentage changes in cash flows between the nine-month periods ending September 30, 2005, and 2004. 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,			
	2005	2004	Change	Percent Change
	(In thousands)			
Net cash provided by operating activities	$ 302,146	$ 157,132	$ 145,014	92%
Net cash used in investing activities	$ (273,272)	$ (109,053)	$ (164,219)	151%
Net cash used in financing activities	$ (8,695)	$ (38,218)	$ 29,523	(77)%

Analysis of cash flow changes between the nine months ended September 30, 2005 and September30, 2004

Operating activities. Cash received from oil and gas sales, net of the effects of hedging, increased $181.3 million to $455.7 million for the nine-month period ended September 30, 2005, from $274.4 million for the nine-month period ended September 30, 2004. This increase was the result of an 18 percent increase in production and a 43 percent increase in our net realized prices between the two periods. Changes in current assets and liabilities combined with cash expenditures for oil and gas production expenses, exploration expenses and administrative expenses increased by $8.9 million between the two comparable periods, and net cash payments made for income taxes increased $27.4 million. The future operating cash flow impact of the increased percentage of hedged production using zero-cost collars will have the effect of reducing the sensitivity to movements in oil and gas prices to the extent prices fall outside of the collar range.

Investing activities. Total 2005 capital expenditures, including acquisitions of oil and gas properties, increased $144.3 million or 108 percent to $278.3 million compared to $133.9 million in 2004. This increase reflects increased drilling expenditures and net cash paid for the acquisitions of Agate Petroleum and oil and gas properties in Wyoming in 2005. The nine-month period ending September 30, 2004, reflects $21.4 million net cash received from short-term investments and from the expiration of the restriction period for funds held for tax-deferred exchange of oil and gas properties.

Financing activities. Net borrowings against our credit facility were $14.3 million for the nine months ended September 30, 2005, versus net repayments of $11.0 million for the same period of 2004. We paid $28.3 million to acquire shares of our common stock under our stock repurchase program in 2005, compared to $19.4 million paid in 2004 to repurchase shares of our common stock and to settle the loan receivable from Flying J and $16.3 million paid in 2004 to acquire shares under our stock repurchase program . We received $1.7 million less for the sale of our common stock for the exercise of stock options in 2005 compared to 2004. Cash paid for dividends was $2.9 million, which is double the $1.4 million paid in 2004 for the comparable period to date, and is a result of doubling our annual dividend rate.

St. Mary had $26.6 million in cash and cash equivalents and had negative working capital of $23.8 million as of September 30, 2005, compared to $6.4 million in cash and cash equivalents and working capital of $12.0 million as of December 31, 2004. The negative working capital does not have an adverse effect to the Company with regard to any of its financial covenants.

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 is $322 million this year, excluding non-cash asset retirement obligation capitalized assets. In addition acquisitions of approximately $87 million have closed this year. This amount includes asset retirement obligation capitalized assets of $9 million. Anticipated ongoing 2005 exploration and development expenditures and budgeted gross wells for each of our core areas are presented in the following table. The timing of drilling and completion of wells is variable and will differ from these estimates.

	Exploration and Development Expenditures	Gross Well Count
	(In millions)	
Mid-Continent region	$ 106	78
Rocky Mountain region	101	149
ArkLaTex region	46	65
Gulf Coast region	34	9
Coalbed Methane	28	165
Permian Basin region	7	21
	$ 322	487

We regularly review our capital expenditure budget to reflect changes in current and projected cash flows, acquisition opportunities, drilling opportunities, debt requirements and other factors. The above allocations are subject to change based on these factors.

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, 2005	2004
	(In thousands)	
Development costs	$ 179,222	$ 118,508
Exploration costs	51,180	29,037
Acquisitions:		
Proved	83,783	8,013
Unproved	2,849	13
Leasing activity	10,696	6,951
Total, including asset retirement obligation	$ 327,730	$ 162,522

Our costs incurred for capital and exploration activities for the nine months ended September 30, 2005, increased $165.2 million or 102 percent compared to the same period in 2004. This increase reflects our 2005 acquisitions of Agate Petroleum and oil and gas properties in Wyoming and also includes budgeted increases in our drilling program.

We continue to develop the coalbed methane reserves in our Hanging Woman Basin project. We completed 64 wells during the first nine months of 2005 and have an additional 30 wells drilled and awaiting completion. Permitting is on schedule to complete approximately 147 wells for the year if the weather permits. We have 154,000 net lease acres in the basin and are concentrating our initial development on 80,000 net acres located in Wyoming. Outstanding legal challenges filed by environmental public interest groups affect our 47,000 net acres of federal land in Montana relating to this project. These challenges may delay our development of the Montana portion of our project as the federal district court has remanded to the BLM the environmental impact statement prepared for the development of coalbed methane projects in southern Montana so that the BLM may further study the effect of phased development. The term of our federal leases will be extended for the time it takes to resolve these legal challenges. Neither St. Mary nor any of its affiliates is a named party in any of these legal challenges.

We believe that internally generated cash flows, together with 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 could lead to changes in funding requirements for future development.

Financing alternatives

The debt and equity financing 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 this segment. As our cash balance and availability under our existing credit facility are significant, we are not currently considering accessing the capital markets in 2005. If additional development or attractive acquisition opportunities arise that exceed our currently available resources, we may consider other forms of financing, including the public offering or private placement of equity or debt securities.

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 and under the caption "*Summary of Interest Rate Hedges in Place.*" Since we produce and sell natural gas and crude oil, 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.

Note 8 of Part I, Item 1 of this report contains important information about our interest rate derivative contracts, and additional information is below under the caption *Summary of Interest Rate Hedges in Place.* 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 for the year ended December 31, 2004.

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. Please refer to Note 8 – Derivative Financial

Instruments in Part I, Item 1 of this report for additional information regarding accounting for our derivative transactions.

Our net realized oil and gas prices are impacted by hedges we have placed on future forecasted 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 acquisition. We also hedge a portion of our forecasted production on a discretionary basis. As previously noted, in October 2005 we entered into a significant volume of zero-cost collar hedging transactions that increased our hedged positions to approximately 10.6 million Bbls and 70.5 million MMBTU of anticipated future production through 2011.

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, we receive the difference between an agreed upon index and the floor price if the index price is below the floor price. 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.

The following tables describe the volumes, average contract prices, and fair value of contracts we have in place as of September 30, 2005. The table also includes hedge contracts entered into after September 30, 2005, however, no fair value information is provided. 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.

Oil Contracts

Oil Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2005 Asset/(Liability)
	(Bbl)	(per Bbl)	(in thousands)
Fourth quarter 2005			
NYMEX WTI	391,770	$ 51.17	$ (5,925)
IF Bow River	3,000	$ 38.40	(25)
First quarter 2006			
NYMEX WTI	385,366	$ 53.23	(5,222)
IF Bow River	24,000	$ 39.16	(191)
Second quarter 2006			
NYMEX WTI	327,976	$ 54.53	(4,001)
IF Bow River	30,000	$ 40.68	(238)
Third quarter 2006			
NYMEX WTI	281,372	$ 54.79	(3,232)
IF Bow River	33,000	$ 40.46	(266)
Fourth quarter 2006			
NYMEX WTI	155,686	$ 50.57	(2,315)
IF Bow River	30,000	$ 37.54	(272)
2007			
NYMEX WTI	314,786	$ 39.78	(7,233)
IF Bow River	76,000	$ 38.85	(734)
2008			
NYMEX WTI	35,000	$ 56.63	(199)
All oil swap contracts			$ (29,853)

Oil Collars*

Contract Period	NYMEX WTI Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2005 Asset/(Liability)*
	(Bbl)	(per Bbl)	(per Bbl)	(in thousands)
Fourth quarter 2005	172,000	$ 51.29	$ 71.94	$ -
First quarter 2006	245,000	$ 51.76	$ 74.13	-
Second quarter 2006	234,000	$ 51.74	$ 74.19	-
Third quarter 2006	222,000	$ 51.72	$ 74.26	-
Fourth quarter 2006	320,000	$ 52.12	$ 73.96	-
2007	1,560,000	$ 50.55	$ 72.86	-
2008	1,668,000	$ 50.00	$ 69.82	-
2009	1,526,000	$ 50.00	$ 67.31	-
2010	1,367,500	$ 50.00	$ 64.91	-
2011	1,236,000	$ 50.00	$ 63.70	-
All oil collars				$ -

* We entered into oil collar transactions subsequent to September 30, 2005. There is no Asset / (Liability) recorded for these instruments as of September 30, 2005.

Gas Contracts

Gas Swaps

Contract Period	Volumes	Weighted-Average Contract Price	Fair Value at September 30, 2005 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(in thousands)
Fourth quarter 2005			
IF ANR OK	1,970,000	$ 7.07	$ (9,024)
IF PEPL	330,000	$ 6.12	(1,938)
IF CIG	360,000	$ 6.78	(1,456)
IF CenterPoint	390,000	$ 6.36	(2,474)
First quarter 2006			
IF ANR OK	1,800,000	$ 8.71	(8,032)
IF PEPL	330,000	$ 6.41	(2,259)
IF CIG	340,000	$ 7.51	(1,689)
IF CenterPoint	390,000	$ 6.56	(2,672)
Second quarter 2006			
IF ANR OK	1,650,000	$ 7.73	(3,433)
IF PEPL	330,000	$ 5.31	(1,421)
IF CIG	330,000	$ 6.30	(880)
IF CenterPoint	380,000	$ 5.67	(1,692)
Third quarter 2006			
IF ANR OK	1,450,000	$ 8.22	(2,153)
IF PEPL	330,000	$ 5.29	(1,419)
IF CIG	300,000	$ 6.35	(745)
IF CenterPoint	360,000	$ 5.67	(1,533)
Fourth quarter 2006			
IF ANR OK	750,000	$ 8.58	(960)
IF PEPL	110,000	$ 5.31	(465)
IF CIG	300,000	$ 6.70	(780)
IF CenterPoint	160,000	$ 5.71	(674)
2007			
IF CIG	630,000	$ 6.42	(1,264)
All gas swap contracts			$ (46,963)

Gas Collars

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2005 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
Fourth quarter 2005				
IF ANR OK	540,000	$ 6.21	$ 7.99	$ (1,976)
IF PEPL	570,000	$ 9.13	$ 19.75	- *
IF HSC	490,000	$ 9.15	$ 20.14	- *
NYMEX Henry Hub	330,000	$ 10.00	$ 24.00	- *
First quarter 2006				
IF ANR OK	150,000	$ 8.00	$ 9.15	(631)
IF PEPL	820,000	$ 9.12	$ 19.78	- *
IF HSC	570,000	$ 8.97	$ 20.99	- *
NYMEX Henry Hub	440,000	$ 10.00	$ 24.00	- *
Second quarter 2006				
IF ANR OK	350,000	$ 6.89	$ 9.13	(457)
IF PEPL	760,000	$ 7.27	$ 13.55	- *
IF CIG	70,000	$ 7.00	$ 11.52	- *
IF HSC	480,000	$ 7.71	$ 13.80	- *
NYMEX Henry Hub	400,000	$ 8.00	$ 14.50	- *
Third quarter 2006				
IF ANR OK	450,000	$ 6.92	$ 9.28	(579)
IF PEPL	720,000	$ 7.27	$ 13.54	- *
IF CIG	210,000	$ 7.00	$ 11.52	- *
IF HSC	430,000	$ 7.71	$ 13.80	- *
NYMEX Henry Hub	330,000	$ 8.00	$ 14.50	- *
Fourth quarter 2006				
IF ANR OK	100,000	$ 7.00	$ 9.82	(115)
IF PEPL	655,000	$ 7.90	$ 14.07	- *
IF CIG	390,000	$ 7.23	$ 12.51	- *
IF HSC	400,000	$ 8.10	$ 14.20	- *
NYMEX Henry Hub	270,000	$ 8.63	$ 15.54	- *
2007				
IF PEPL	7,960,000	$ 7.35	$ 10.74	- *
IF CIG	3,120,000	$ 6.66	$ 9.36	- *
IF HSC	1,240,000	$ 7.84	$ 10.60	- *
NYMEX Henry Hub	790,000	$ 8.28	$ 11.32	- *

Gas Collars (continued)

Contract Period	Volumes	Weighted-Average Floor Price	Weighted-Average Ceiling Price	Fair Value at September 30, 2005 Asset/(Liability)
	(MMBtu)	(per MMBtu)	(per MMBtu)	(in thousands)
2008				
IF PEPL	6,600,000	$ 6.28	$ 9.42	- *
IF CIG	2,880,000	$ 5.60	$ 8.72	- *
IF HSC	960,000	$ 6.57	$ 9.70	- *
NYMEX Henry Hub	480,000	$ 7.00	$ 10.57	- *
2009				
IF PEPL	5,510,000	$ 5.30	$ 9.25	- *
IF CIG	2,400,000	$ 4.75	$ 8.82	- *
IF HSC	840,000	$ 5.57	$ 9.49	- *
NYMEX Henry Hub	360,000	$ 6.00	$ 10.35	- *
2010				
IF PEPL	4,945,000	$ 5.31	$ 7.61	- *
IF CIG	2,040,000	$ 4.85	$ 7.08	- *
IF HSC	600,000	$ 5.57	$ 7.88	- *
NYMEX Henry Hub	240,000	$ 6.00	$ 8.38	- *
2011				
IF PEPL	4,225,000	$ 5.31	$ 6.51	- *
IF CIG	1,800,000	$ 5.00	$ 6.32	- *
IF HSC	480,000	$ 5.57	$ 6.77	- *
NYMEX Henry Hub	120,000	$ 6.00	$ 7.25	- *
All gas collars				$ (3,758)

* We entered into the indicated gas collar transactions subsequent to September 30, 2005. As such, there is no fair value for these instruments as of September 30, 2005.

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

Summary of Interest Rate Hedges in Place

We entered into fixed-rate to floating-rate interest rate swaps on $50 million of convertible notes on October 3, 2003. Due to continuing increases in interest rates, we entered into a floating-to-fixed interest rate swap on April 13, 2005, through March 20, 2007, on this same notional amount of $50 million in order to effectively offset our fixed-to-floating interest rate swaps. Under the floating-to-fixed interest rate swap, we will be paid a variable interest rate of 235 basis points above the six-month LIBOR rate as determined on the semi-annual settlement date and will pay a fixed interest rate of 6.85 percent. The impact of this instrument, when combined with the other interest rate swaps, is that we have fixed our net liability related to the interest rate swaps, and we will pay a 1.1 percent interest factor on $50 million of notional debt through March 2007. The payment dates of the swap match exactly with the interest payment dates of the convertible notes and the fixed-to-floating interest rate swaps. We anticipate that increasing interest rates will result in higher interest expense for us in 2005 compared to last year.

Market risk is estimated as the potential change in fair value resulting from an immediate hypothetical one-percentage point parallel shift in the yield curve. For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely, interest rate changes for floating-rate debt generally do not affect the fair market value but do impact future results of operations and cash flows, assuming other factors are held constant. The carrying amount of our floating-rate debt approximates its fair value. Giving consideration to all interest rate swaps in effect on September 30, 2005, we had floating-rate debt of $52 million and fixed-rate debt of $100 million as of that date. Assuming constant debt levels, the cash flow impact for the remainder of the year resulting from a one-percentage point change in interest rates would be approximately $131,000 before taxes. The results of operations impact might be less than this amount as a direct effect of the capitalization of interest to wells drilled during the year. In prior years when our debt amount was at a reduced level we capitalized a larger percentage of our interest expense. Since we cannot predict the exact amount that would be capitalized, we cannot predict the exact effect that a one-percentage point shift would have on the results of operations.

We anticipate that interest expense in 2005 will be higher than in 2004. Please see Note 8 of Part I, Item 1 of this report for additional information regarding our interest rate swaps.

Schedule of Contractual Obligations

The following table summarizes our future estimated principal payments and minimum lease payments for the periods specified (in millions):

Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 161.4	$ 6.3	$ 103.1	$ 52.0	$ -
Operating Leases	9.7	2.5	4.1	2.4	0.7
Other Long-Term Liabilities	23.8	2.5	18.8	1.3	1.2
Total	$ 194.9	$ 11.3	$ 126.0	$ 55.7	$ 1.9

This table includes our 2006 estimated pension liability payment of approximately $1.3 million but excludes the remaining unfunded portion of our estimated pension liability of $1.5 million since we cannot determine with accuracy the timing of future payments. The table does not include estimated payments associated with our Net Profits Interest Plan. We record a liability for the estimated future payments. However, predicting the precise timing and amount of the liability payments is contingent upon realized pricing, costs and production from the underlying oil and gas properties. We have excluded asset retirement obligations because we are not able to precisely predict the timing for these amounts. The Net Profits Interest Plan, pension liabilities and asset retirement obligations are discussed in Note 7, Note 8 and Note 9, respectively, of Part IV Item 15 of our Form 10-K for the year ended December 31, 2004, and also in Note 5, Note 9 and Note 10, respectively, of Part I, Item 1 of this report.

Three leases for office space will expire in year two and one office space lease will expire in year three. Estimated costs to replace these leases are not included in the table above. For purposes of the table we assume that the holders of our convertible notes will not exercise the conversion feature. If the holders do exercise their conversion feature, we will not have to repay the $100 million, and our common shares outstanding would increase by 7,692,307 shares.

Beginning with the dividend payment we made in May 2005, we have effectively doubled our annual dividend rate from prior years. We believe that we will continue to pay the semi-annual dividend of $0.05 per share for the foreseeable future.

Off-Balance Sheet Arrangements

We do not have any 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 for the year ended December 31, 2004, and to the footnote disclosures included in Part I, Item 1 of this report.

Additional Comparative Data in Tabular Form:

	Change Between the Three Months Ended September 30, 2005 and 2004	Change Between the Nine Months Ended September 30, 2005 and 2004
Oil and gas production revenues		
Increase in oil and gas production revenues, net of hedging (in thousands)	$ 91,512	$ 201,722

Components of Revenue Increases (Decreases):

Natural Gas		
Realized price change per Mcf	$ 2.54	$ 1.68
Realized price percentage change	48%	32%
Production change (MMcf)	2,362	4,911
Production percentage change	20%	14%
Oil		
Realized price change per Bbl	$ 22.08	$ 19.01
Realized price percentage change	65%	61%
Production change (MBbl)	289	849
Production percentage change	23%	24%

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	2005	2004	2005	2004
Natural gas	56%	59%	55%	62%
Oil	44%	41%	45%	38%
Production				
Natural gas	60%	61%	60%	62%
Oil	40%	39%	40%	38%

Information Regarding the Components of Exploration Expense:

Summary of Exploration Expense	For the Three Months Ended September 30, 2005	For the Three Months Ended September 30, 2004	For the Nine Months Ended September 30, 2005	For the Nine Months Ended September 30, 2004
	(In millions)		(In millions)	
Geological and geophysical expenses	$ 1.4	$ 3.2	$ 4.9	$ 5.3
Exploratory dry hole expense	0.4	1.3	2.5	2.5
Overhead and other expenses	8.9	4.4	20.1	12.3
Total	$ 10.7	$ 8.9	$ 27.5	$ 20.1

Information Regarding the Effects of Oil and Gas Hedging Activity:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Natural Gas Hedging	2005	2004	2005	2004
Percentage of gas production hedged	19%	24%	21%	25%
Natural gas MMBtu hedged	2.9 million	3.0 million	9.0 million	9.6 million
Increase (decrease) in gas revenue	$ (2.8 million)	$ (3.4 million)	$ 929,000	$(10.5 million)
Average realized gas price per Mcf before hedging	$ 8.03	$ 5.59	$ 6.95	$ 5.61
Average realized gas price per Mcf after hedging	$ 7.83	$ 5.29	$ 6.98	$ 5.30
Oil Hedging				
Percentage of oil production hedged	19%	43%%	20%	43%
Oil volumes hedged (MBbl)	292	530	860	1,512
Decrease in oil revenue	$ (5.7 million)	$ (9.9 million)	$ (9.9 million)	$(22.5 million)
Average realized oil price per Bbl before hedging	$ 59.66	$ 41.84	$ 52.30	$ 37.40
Average realized oil price per Bbl after hedging	$ 55.95	$ 33.87	$ 50.05	$ 31.04

Comparison of Financial Results and Trends between the Quarters ended September 30, 2005 and 2004

Oil and gas production revenue. Average net daily production increased 22 percent to a record 251.1 MMCFE per day for the quarter ended September 30, 2005, compared with 206.5 MMCFE per day for the quarter ended September 30, 2004. The following table presents specific components that contributed to the increase in revenue between the two quarters:

	Average Net Daily Production Added	Oil and Gas Revenue Added	Production Costs Added
	(MMCFE)	(In millions)	(In millions)
Paggi-Broussard 1 (SM 40%)	13.2	$ 10.9	$ 0.1
Williston Basin Middle Bakken Play	20.1	16.0	1.0
Other wells completed in 2004 and 2005	21.3	24.3	3.6
Goldmark acquisition	3.7	2.8	1.2
Border acquisition	8.5	6.2	0.7
Agate acquisition	5.3	4.3	1.4
Southern Rockies acquisition	4.4	3.4	0.9
Other acquisitions	0.2	0.5	0.2
Total	76.7	$ 68.4	$ 9.1

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.

Oil and gas production expense. Total production costs increased $13.9 million, or 58 percent, to $38.1 million for the third quarter of 2005 from $24.2 million in the comparable period of 2004. As noted in the table above, completed wells and acquisitions in 2004 and 2005 have added $9.1 million of incremental production costs in 2005. Additionally, we experienced an increase in value-based production taxes consistent with an increase in revenue from crude oil and natural gas due to higher oil and gas prices.

Total oil and gas production costs per MCFE increased $0.38 to $1.65 for 2005, compared with $1.27 for 2004. This increase is comprised of the following:

- A $0.04 increase in production taxes in our Mid-Continent region resulting from higher natural gas revenues and the suspension of Oklahoma severance tax incentives in 2005 due to average natural gas prices in excess of price caps;
- A $0.12 increase in production taxes due to higher revenue from crude oil in our Rocky Mountain and Permian regions;
- A $0.02 increase in production taxes in our ArkLaTex and Gulf coast regions reflecting higher natural gas prices offset by additional benefits from severance tax incentive credits received from Louisiana and Texas;
- A $0.03 decrease in transportation cost that offsets a corresponding decrease in revenue received from natural gas sales;
- A $0.07 increase in LOE reflecting a general 7 percent increase that we had forecasted in our budget process that was caused by competition for resources;
- A $0.14 increase in LOE reflecting cost increases that we had not forecasted in our budget process and that was caused by competition for resources;
- A $0.03 increase due to the start-up activity in our Hanging Woman Basin coalbed methane project; and
- A $0.01 overall decrease in LOE relating to workover charges.

General and administrative. General and administrative expenses increased $4.3 million or 79 percent to $9.8 million for the quarter ended September 30, 2005, compared with $5.5 million for the comparable period of 2004. G&A increased $0.13 to $0.42 per MCFE for the third quarter of 2005 compared to $0.29 per MCFE for the same three-month period in 2004 as G&A grew at a faster rate than the 22 percent increase in production.

A 24 percent increase in employee count has resulted in an increase in base employee compensation of $896,000 between the third quarter of 2005 and the third quarter of 2004. Oil and gas price increases have triggered additional Net Profits Interest Plan payouts and have increased the amounts payable to plan participants. Consequently, the current period realized expense associated with the Net Profits Interest Plan has increased by $4.0 million in 2005, and cash and RSU bonus expense is $4.2 million higher than in the year prior. The increase in Net Profits Interest Plan payments is the result of the significantly higher oil and gas prices, which has the effect of increasing the absolute amount of payments as well as accelerating the time it takes for pools to reach payout. It is expected that 17 of the Company's 19 pools will be in payout status as of the end of 2005. The cash and RSU bonus percentage is higher than last year as a result of the Company's overall performance, which include an evaluation of reserve replacement, production increases and net asset value per share enhancement.

The incentive plan compensation increases combined with a net $858,000 increase in other compensation expense were mostly offset by increases in COPAS overhead reimbursements and allocation of G&A to exploration expense. COPAS overhead reimbursement from operations increased $989,000 due to an increase in operated well count resulting from our drilling and acquisition programs. The amount of G&A we allocated to exploration expense increased $4.5 million due to incentive plan payment increases and increases in our technical exploration staff.

Change in Net Profits Interest Plan Liability. For the quarter ended September 30, 2005, this non-cash expense increased $47.3 million to $54.9 million from $7.5 million for 2004. This increase reflects our estimation of the effect of a sustained higher price environment and the impact of hedge contracts entered into in 2005 on the performance of individual pools as previously described. 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. This expense will be significantly higher in 2005 than in 2004.

Income taxes. Income tax expense totaled $15.0 million for the third quarter of 2005 and $12.6 million for the third quarter of 2004 resulting in effective tax rates of 35.4 percent and 35.8 percent, respectively. The effective rate change from 2004 reflects changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity and also reflects other permanent differences including the estimated effect of the domestic production activities deduction from the American Jobs Creation Act of 2004.

Comparison of Financial Results and Trends between the nine months ended September 30, 2005 and 2004

Oil and gas production revenue. Average net daily production increased 18 percent to 239.9 MMCFE for the nine months ended September 30, 2005, compared with 202.5 MMCFE for the nine months ended September 30, 2004. The following table presents specific components that contributed to the increase in revenue between the two periods:

	Average Net Daily Production Added	Oil and Gas Revenue Added	Production Costs Added
	(MMCFE)	(Millions)	(Millions)
Paggi-Broussard 1 (SM 40%)	12.4	$ 27.0	$ 0.3
Williston Basin Middle Bakken Play	13.6	34.2	1.6
Other wells completed in 2004 and 2005	26.4	67.4	9.9
Goldmark acquisition	3.5	5.9	3.4
Border acquisition	6.5	11.7	1.5
Agate acquisition	5.2	10.7	3.8
Southern Rockies acquisition	1.5	3.4	0.9
Other acquisitions	0.7	1.6	0.5
Total	69.8	$ 161.9	$ 21.9

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.

Oil and gas production expense. Total production costs increased $31.1 million or 45 percent during the nine-month period to $100.4 million in 2005 from $69.3 million in 2004. As noted in the table above, completed wells and acquisitions in 2004 and 2005 have added $21.9 million of incremental production costs in 2005. Additionally, we experienced an increase in value-based production taxes in 2005 consistent with an increase in revenue from crude oil and natural gas due to higher prices, and we benefited from accrued Oklahoma severance tax incentives in 2004 that were suspended in 2005.

Total oil and gas production costs per MCFE increased $0.27 to $1.53 for 2005, compared with $1.26 for 2004. This increase is comprised of the following:

- A $0.07 increase in production taxes in our Mid-Continent region resulting from higher natural gas revenues and the suspension of Oklahoma severance tax incentives in 2005 due to average natural gas prices in excess of price caps;
- A $0.09 increase in production taxes due to higher revenue from crude oil in our Rocky Mountain and Permian regions;
- A $0.07 increase in LOE reflecting a general 7 percent increase that we had forecasted in our budget process and that was caused by competition for resources;
- A $0.07 increase in LOE reflecting a general increase that we had not forecasted in our budget process and that was caused by competition for resources;
- A $0.03 increase due to the start-up activity in our Hanging Woman Basin coalbed methane project; and
- A $0.05 overall decrease in LOE relating to workover charges.

General and administrative. General and administrative expenses increased $6.8 million or 41 percent to $23.2 million for the nine months ended September 30, 2005, compared with $16.5 million for the nine months ended September 30, 2004. G&A increased $0.05 to $0.35 per MCFE for the nine-month period of 2005 compared to $0.30 per MCFE for the nine-month period of 2004 as the percentage increase in G&A was greater than the 18 percent increase in production.

The increase in employee count has resulted in an increase in general and administrative expenses of $3.5 million between the first nine months of 2005 and the first nine months of 2004. Accounting fee increases of $238,000 and charitable contribution expense increases of $533,000 were completely offset by a decrease in other professional fees of $756,000, which reflects initial Sarbanes-Oxley compliance and other consulting projects in 2004 that were not repeated in 2005. The current period realized expense associated with the Net Profits Interest Plan has increased by $8.1 million to $13.7 million in 2005 as compared to $5.6 million in 2004, and cash and RSU bonus expense has increased $5.5 million to $10.0 million. These increases were mostly offset by COPAS overhead reimbursements and allocation of G&A to exploration expense. COPAS overhead reimbursement from operations increased $2.4 million due to an increase in operated well count resulting from our drilling and acquisition programs. The amount of G&A we allocated to exploration expense increased $7.8 million due to incentive plan payment increases and increases in our technical exploration staff.

Change in Net Profits Interest Plan liability. This expense increased $57.2 million to $71.3 million for the nine months ended September 30, 2005, compared to $14.0 million for the nine months ended September 30, 2004. The increase reflects sustained higher oil and gas prices and the impact of hedge contracts entered into in 2005. See the detailed discussion in the overview to MD&A and in the three month comparison.

Interest expense. Interest expense increased by $2.0 million to $6.6 million for 2005 compared to $4.5 million for 2004. The increase reflects an increase in our average outstanding borrowings and higher interest rates on the floating rate portion of our long-term debt. Additionally, we received benefits from fixed-to-floating interest rate swaps in effect during 2004 that were effectively offset by floating-rate-to-fixed-rate interest rate swaps we entered into in April 2005.

Income taxes. Income tax expense totaled $58.0 million for the first three quarters of 2005 and $39.1 million for the comparable period in 2004, resulting in effective tax rates of 36.5 percent and 37.2 percent, respectively. The effective rate change from 2004 reflects changes in the mix of the highest marginal state tax rates as a result of acquisition and drilling activity and also reflects other permanent differences including the estimated effect of the domestic production activities deduction from the American Jobs Creation Act of 2004.

The current portion of the income tax expense in 2005 is $48.5 million compared to $15.5 million in 2004. These amounts are 84 percent and 40 percent of the total tax for the respective periods. Although we increased our 2005 budget for drilling expenditures over 2004 amounts, our projections are for even larger increases in revenue due to anticipated production and pricing. In addition, the change in Net Profits Interest Plan liability is not currently deductible for income tax purposes and has a significantly higher impact on the percentage of the current portion of income tax expense in 2005 than in 2004. As a result of these factors, we believe that current taxable income and the resulting current portion of income tax as a percentage of total income tax will be significantly higher in 2005 than it was in 2004.

Accounting Matters

We refer you to Note 2 and Note 5 of Part I, Item 1 of this report for information regarding accounting matters.

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 Statement About Forward - Looking Statements

This Quarterly Report on Form 10-Q includes certain statements that may be deemed to be "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 St. Mary's management expects, believes or anticipates will or may occur in the future are forward-looking statements. The words "will," "believe," "anticipate," "intend," "estimate," "expect," "project," and similar expressions are intended to identify forward - looking statements, although not all forward - looking statements contain such identifying words. Examples of forward-looking statements may include discussion of such matters as:

- *the amount and nature of future capital, development and exploration expenditures,*
- *the drilling of wells,*
- *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,*
- *repayment of debt,*
- *business strategies,*
- *expansion and growth of operations,*
- *recent legal developments, and*
- *other similar matters.*

These statements are based on certain 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 we believe are appropriate under the circumstances. Such statements are subject to a number of assumptions, risks and uncertainties, including such factors as the volatility and level of oil and natural gas prices, unexpected drilling conditions and results, production rates and reserve replacement, the imprecise nature of oil and gas reserve estimates, drilling and operating service availability and risks, uncertainties in cash flow, the financial strength of hedge contract *counterparties, the availability of attractive exploration, development and property acquisition opportunities, financing requirements, expected acquisition benefits, competition, litigation, environmental matters, the potential impact of government regulations, and other matters discussed in the "Risk Factors" section of our 2004 Annual Report on Form 10-K. Readers are cautioned 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," "Summary of Oil and Gas Production Hedges in Place," and "Summary of Interest Rate 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 significant 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 6. EXHIBITS

The following exhibits are furnished as part of this report:

Exhibit	Description
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

* Filed 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 4, 2005	By:	/s/ MARK A. HELLERSTEIN Mark A. Hellerstein President and Chief Executive Officer
November 4, 2005	By:	/s/ DAVID W. HONEYFIELD David W. Honeyfield Vice President - Chief Financial Officer, Secretary and Treasurer
November 4, 2005	By:	/s/ GARRY A. WILKENING Garry A. Wilkening Vice President - Administration and Controller

CEO CERTIFICATION FOR
THIRD QUARTER 2005 FORM 10-Q

I, Mark A. Hellerstein, certify that:

1. I have reviewed this quarterly report on Form 10-Q of St. Mary Land & Exploration Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the

audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2005

/S/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chief Executive Officer

CFO CERTIFICATIONS FOR
THIRD QUARTER 2005 FORM 10-Q

I, David W. Honeyfield, certify that:

1. I have reviewed this quarterly report on Form 10-Q of St. Mary Land & Exploration Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the

audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2005

/S/ DAVID W. HONEYFIELD
David W. Honeyfield
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION
PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of St. Mary Land & Exploration Company (the "Company") for the quarterly period ended September 30, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), Mark A. Hellerstein, as Chief Executive Officer of the Company, and David W. Honeyfield, as Chief Financial Officer of the Company, each hereby certifies, pursuant to and solely for the purpose of 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of his knowledge and belief, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/S/ MARK A. HELLERSTEIN
Mark A. Hellerstein
Chief Executive Officer
November 2, 2005

/S/ DAVID W. HONEYFIELD
David W. Honeyfield
Chief Financial Officer
November 2, 2005

EXHIBIT 99.1

Audit Committee Pre-Approval of Non-Audit Services

On July 21, 2005, the Audit Committee of the Board of Directors of St. Mary Land & Exploration Company approved in advance certain non-audit services to be performed by Deloitte & Touche LLP, St. Mary’s independent auditor. These non-audit services were corporate income tax compliance services in the third quarter of 2005.