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, 2002

Commission file number 000-20872

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)

1776 Lincoln Street, Suite 1100, Denver, Colorado 80203
(Former address, changed since last report)

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

As of November 8, 2002, the issuer had 27,931,780 shares of common stock, $.01 par value, outstanding.

ST. MARY LAND & EXPLORATION COMPANY

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

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

ASSETS

	September 30, 2002	December 31, 2001
Current assets:		
Cash and cash equivalents	$ 49,070	$ 4,116
Short term investments available-for-sale	10,474	-
Accounts receivable	34,598	46,484
Prepaid expenses and other	3,780	2,337
Accrued derivative asset	5,973	8,194
Refundable income taxes	1,894	11,090
Total current assets	105,789	72,221
Property and equipment (successful efforts method), at cost:		
Proved oil and gas properties	593,361	523,823
Less accumulated depletion, depreciation and amortization	(249,860)	(216,288)
Unproved oil and gas properties, net of impairment allowance of $9,025 in 2002 and $8,908 in 2001	42,412	48,143
Other property and equipment, net of accumulated depreciation of $3,285 in 2002 and $3,120 in 2001	3,519	3,252
Total property and equipment	389,432	358,930
Other noncurrent assets	9,135	5,838
Total Assets	$ 504,356	$ 436,989

LIABILITIES AND STOCKHOLDERS' EQUITY

	September 30, 2002	December 31, 2001
Current liabilities:		
Accounts payable and accrued expenses	$ 41,602	$ 34,858
Deferred tax liability	979	3,363
Total current liabilities	42,581	38,221
Long-term liabilities:		
Long-term credit facility	-	64,000
Convertible notes	99,578	-
Deferred income taxes	57,197	47,685
Other noncurrent liabilities	1,914	255
Total long-term liabilities	158,689	111,940
Commitments and contingencies		
Minority interest	712	711
Stockholders' equity:		
Common stock, $0.01 par value: authorized - 100,000,000 shares: Issued and outstanding - 28,907,736 shares in 2002 and 28,779,808 shares in 2001	289	288
Additional paid-in capital	139,351	137,384
Treasury stock - at cost: 1,009,900 shares in 2002 and 2001	(16,210)	(16,210)
Retained earnings	176,929	157,739
Accumulated other comprehensive income	2,015	6,916

Total stockholders' equity	302,374	286,117
Total Liabilities and Stockholders' Equity	$ 504,356	$ 436,989

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,	
	2002	2001	2002	2001
Operating revenues:				
Oil and gas production	$ 45,121	$ 41,859	$ 132,411	$ 165,195
Loss on sale of proved properties	(503)	(71)	(90)	(21)
Marketed gas revenue	3,366	-	6,810	-
Other oil and gas revenue	185	374	932	939
Gain on sale of KMOC stock	-	-	836	-
Other revenues	166	494	237	666
Total operating revenues	48,335	42,656	141,136	166,779
Operating expenses:				
Oil and gas production	12,392	14,756	37,953	40,249
Depletion, depreciation and amortization	12,836	13,704	39,169	37,876
Exploration	4,219	4,347	15,432	14,858
Impairment of proved properties	-	576	-	820
Abandonment and impairment of unproved properties	587	659	1,906	1,733
General and administrative	4,388	2,804	10,544	10,361
Unrealized derivative loss (gain)	(2,619)	-	(4,594)	-
Marketed gas expense	3,545	-	6,631	-
Minority interest and other	286	283	906	662
Total operating expenses	35,634	37,129	107,947	106,559
Income from operations	12,701	5,527	33,189	60,220
Nonoperating income (expense):				
Interest income	288	73	568	408
Interest expense	(1,110)	(5)	(2,580)	(40)
Income before income taxes	11,879	5,595	31,177	60,588
Income tax expense	4,205	734	10,596	21,100
Net income	$ 7,674	$ 4,861	$ 20,581	$ 39,488
Basic net income per common share	$ 0.28	$ 0.17	$ 0.74	$ 1.41
Diluted net income per common share	$ 0.27	$ 0.17	$ 0.72	$ 1.38
Basic weighted average common shares outstanding	27,873	27,790	27,828	28,052
Diluted weighted average common shares outstanding	28,448	28,252	28,388	28,620

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,	
	2002	2001
Reconciliation of net income to net cash provided by operating activities:		
Net income	$ 20,581	$ 39,488

Adjustments to reconcile net income to net cash provided by operating activities:		
Loss on sale of proved properties	90	21
Gain on sale of KMOC stock	(836)	-
Depletion, depreciation and amortization	39,169	37,876
Impairment of proved properties	-	820
Abandonment and impairment of unproved properties	1,906	1,733
Unrealized derivative gain	(4,594)	-
Deferred income taxes	10,287	18,700
Exploratory dry hole expense	7,293	5,914
Minority interest and other	(1,208)	(199)
	72,688	104,353
Changes in current assets and liabilities:		
Accounts receivable	12,962	9,647
Prepaid expenses and other	(1,442)	(741)
Refundable income taxes	9,215	(7,029)
Accounts payable and accrued expenses	13,000	5,476
Current deferred income taxes	(271)	163
Net cash provided by operating activities	106,152	111,869
Cash flows from investing activities:		
Proceeds from sale of oil and gas properties	166	1,469
Capital expenditures	(65,106)	(99,844)
Acquisition of oil and gas properties	(21,574)	(1,620)
Proceeds from distribution and sale of KMOC stock	3,114	7,371
Deposits to short term investments available-for-sale	(11,484)	-
Receipts from short term investments available-for-sale	1,000	-
Other	26	(118)
Net cash used in investing activities	(93,858)	(92,742)
Cash flows from financing activities:		
Proceeds from credit facility	16,000	75,200
Repayment of credit facility	(80,000)	(82,850)
Proceeds from issuance of convertible notes	96,661	-
Proceeds from sale of common stock	1,390	2,381
Repurchase of common stock	-	(12,871)
Dividends paid	(1,391)	(1,408)
Net cash provided by (used in) financing activities	32,660	(19,548)
Net change in cash and cash equivalents	44,954	(421)
Cash and cash equivalents at beginning of period	4,116	6,619
Cash and cash equivalents at end of period	$ 49,070	$ 6,198

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,	
	2002	2001
	(In thousands)	
Cash paid for interest	$ 2,795	$ 284
Cash paid (received) for income taxes	(8,635)	10,386
Cash paid for exploration expenses	18,616	10,499

In June 2002 the Company issued 800 shares of common stock to a director and recorded compensation expense of $14,763.

In January 2002 the Company issued 7,200 shares of common stock to its directors and recorded compensation expense of $129,683.

In January 2001 the Company issued 8,400 shares of common stock to its directors and recorded compensation expense of $237,852.

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
(In thousands, except share amounts)

	Common Stock		Additional Paid-in Capital	Retained Earnings	Treasury Stock		Accumulated Other Comprehensive Income	Total Stockholders' Equity
	Shares	Amount			Shares	Amount		
Balances, December 31, 2000	28,553,826	$ 286	$ 132,973	$ 120,075	(395,600)	$ (3,339)	$ 141	$ 250,136
Comprehensive income:								
Net Income	-	-	-	40,459	-	-	-	40,459
Unrealized net loss on marketable equity securities available for sale	-	-	-	-	-	-	(132)	(132)
Adoption of SFAS No. 133							(28,587)	(28,587)
Change in derivative instrument fair value	-	-	-	-	-	-	35,494	35,494
Total comprehensive income								47,234
Cash dividends, $ 0.10 per share	-	-	-	(2,795)	-	-	-	(2,795)
Treasury stock purchases	-	-	-	-	(614,300)	(12,871)	-	(12,871)
Issuance for Employee Stock Purchase Plan	29,772	-	575	-	-	-	-	575
Sale of common stock, including income tax benefit of stock option exercises	187,810	2	3,598	-	-	-	-	3,600
Directors' stock compensation	8,400	-	238	-	-	-	-	238
Balances, December 31, 2001	28,779,808	$ 288	$ 137,384	$ 157,739	(1,009,900)	$ (16,210)	$ 6,916	$ 286,117
Comprehensive income:								
Net Income	-	-	-	20,581	-	-	-	20,581
Unrealized net loss on marketable equity securities available for sale	-	-	-	-	-	-	(452)	(452)
Change in derivative instrument fair value	-	-	-	-	-	-	(4,449)	(4,449)
Total comprehensive income								15,680
Cash dividends, $ 0.05 per share	-	-	-	(1,391)	-	-	-	(1,391)
Issuance for Employee Stock Purchase Plan	9,294	-	167	-	-	-	-	167
ESPP disqualified distribution	-	-	21	-	-	-	-	21
Sale of common stock, including income tax benefit of stock option exercises	110,634	1	1,634	-	-	-	-	1,635
Directors' stock compensation	8,000	-	145	-	-	-	-	145
Balances, September 30, 2002	28,907,736	$ 289	$ 139,351	$ 176,929	(1,009,900)	$ (16,210)	$ 2,015	$ 302,374

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

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

September 30, 2002

Note 1 - Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of St. Mary Land & Exploration Company and Subsidiaries ("St. Mary" or the "Company") 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, 2001. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. Operating results for the periods presented are not necessarily indicative of the results that may be expected for the full year.

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, 2001. 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 2 - Income Taxes

Federal income tax expense for the three and nine months ended September 30, 2002, and 2001 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 Section 29 credits, percentage depletion, interest expense on convertible debt with contingent interest provisions, and the effect of state income taxes. For the nine months ended September 30, 2002, the Company's current portion of income tax expense was $502,000.

Note 3 - Long-term Debt

In March 2002 the Company issued in a private placement a total of $100,000,000 of 5.75% senior convertible notes due 2022 (the "Notes") with a 0.5% contingent interest provision (see Note 4). The contingent interest provision did not apply to St. Mary's first interest payment on September 15, 2002, but it will apply to the payment due on March 15, 2003. Interest payments will be made on March 15 and September 15 in subsequent years. The Company received net proceeds of $96,661,000 after deducting the initial purchasers' discount and offering expenses paid by the Company. The Notes are general unsecured obligations and rank on parity in right of payment with all existing and future unsecured senior indebtedness and other general unsecured obligations. They are senior in right of payment to all future subordinated indebtedness. The Notes are convertible into the Company's common stock at a conversion price of $26.00 per share, subject to adjustment. The Company can redeem the Notes with cash in whole or in part at a repurchase price of 100% of the principal amount plus accrued and unpaid interest (including contingent interest) beginning on March 20, 2007. The note holders have the option of requiring the Company to repurchase the Notes for cash at 100% of the principal amount plus accrued and unpaid interest (including contingent interest) upon (1) a change in control of St. Mary or (2) on March 20, 2007, March 15, 2012, and March 15, 2017. If the note holders require repurchase on March 20, 2007, the Company may pay the repurchase price with cash, shares of its common stock valued at a discount to the market price at the time of repurchase or any combination of cash and its discounted common stock. St. Mary is not restricted

from paying dividends, incurring debt, or issuing or repurchasing its securities under the indenture for the Notes. There are no financial covenants in the indenture. The Company used a portion of the net proceeds from the Notes to repay its credit facility balance and will use the remaining net proceeds to fund a portion of its 2002 capital budget. On March 25, 2002, the Company entered into a five-year fixed-rate to floating-rate interest rate swap on $50,000,000 of Notes. The floating rate for each applicable six-month period will be determined as LIBOR plus 0.36%. For the current six-month calculation period this rate is 2.19%. See "Note 4 - Financial Instruments" for a discussion of the derivative accounting for the interest rate swap.

The stated total borrowing base under the Company's current long-term revolving credit agreement was decreased $10,000,000 to $160,000,000 in April 2002. The accepted borrowing base is currently $40,000,000. Pursuant to a March 4, 2002, amendment to the credit agreement, during the revolving period of the loan, loan balances will accrue interest at the Company's option of either (1) the higher of the federal funds rate plus 0.5% or the prime rate, plus an additional 0.25% when the Company's debt to capitalization ratio is greater than 50%, or (2) the LIBOR rate plus (a) 1% when the Company's debt to total capitalization ratio is less than 30%, (b) 1.25% when the Company's debt to capitalization ratio is greater than or equal to 30% but less than 40%, (c) 1.375% when the Company's debt to capitalization ratio is greater than or equal to 40% but less than 50%, or (d) 1.625% when the Company's debt to capitalization ratio is greater than 50%. At September 30, 2002, the Company's debt to capitalization ratio as defined under the credit agreement was 25.0%.

The Company had no outstanding borrowings under its revolving credit agreement and $100,000,000 in outstanding borrowings under the Notes as of September 30, 2002. The weighted average interest rate paid for the third quarter of 2002 was 4.38% including commitment fees paid on the unused portion of the revolving credit facility accepted borrowing base. Borrowings under the facility are secured by a pledge of collateral in favor of the banks and guarantees by subsidiaries. Such collateral consists primarily of security interests in the oil and gas properties of St. Mary and its subsidiaries.

Note 4 - Financial Instruments

The Company seeks to protect its rate of return on acquisitions of producing properties by hedging cash flow when the economic criteria from its evaluation and pricing model indicate it would be appropriate. Management's strategy is to hedge cash flows from investments requiring a gas price in excess of $3.25 per Mcf and an oil price in excess of $22.50 per Bbl in order to meet minimum rate-of-return criteria. The Company anticipates this strategy will result in the hedging of future cash flow from acquisitions. St. Mary generally limits its aggregate hedge position to no more than 35% of its total production but will hedge larger percentages of total production in certain circumstances. The Company seeks to minimize basis risk and indexes the majority of oil hedges to NYMEX prices and the majority of gas hedges to various regional index prices associated with pipelines in proximity to its areas of gas production.

On February 4, 2002, the Company entered into an agreement to monetize its unrealized hedge gain receivable due from Enron for $1,118,000. This amount was included in other comprehensive income at December 31, 2001, and was recorded as a hedge gain in the first quarter of 2002. Hedge gains and losses are reported in oil and gas production revenues in the consolidated statements of operations. Amortization of $1,242,000 of other comprehensive income related to commodity positions with Enron is also recorded as a hedge gain in oil and gas production revenue in the consolidated statements of operations for the nine months ended September 30, 2002. Additional amortization will be recorded in hedge gains in future months. Unrealized derivative loss in the consolidated statements of operations includes $4,000 of net loss from oil and gas hedge ineffectiveness.

The Notes contain a provision for payment of contingent interest if certain conditions are met. Under Statement of Financial Accounting Standards ("SFAS") No. 133 this provision 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 separated from the Notes and accounted for as a derivative instrument. The value of the derivative at issuance in March 2002 was $474,000.

This amount was recorded as an adjustment to the Notes in the consolidated balance sheets in the first quarter of 2002. Of this amount, $51,000 has been amortized through interest expense for the nine months ended September 30, 2002. Unrealized derivative loss in the consolidated statements of operations includes $239,000 of net loss from mark-to-market adjustments for this derivative for the nine months ended September 30, 2002.

The fixed-rate to floating-rate interest rate swap on $50,000,000 of Notes did not qualify for fair value hedge treatment under SFAS No. 133. Unrealized derivative gain in the consolidated statements of operations includes $4,838,000 of net gain from mark-to-market adjustments for this derivative instrument for the nine months ended September 30, 2002.

The Company anticipates that all oil and gas hedge transactions will occur as expected. Based on current prices we anticipate that $2,399,000 of the after tax gain amount included in accumulated other comprehensive income will be included in earnings during the next 12 months.

Note 5 - Short-term Investments Available-for-Sale

The following short-term interest-bearing investment-grade securities available for sale will mature within one year:

Major security type	Amortized Cost Basis	Gross Unrealized Holding Gains	Aggregate Fair Value
Debt securities issued by government agencies	$ 991,396	$ 382	$ 991,778
Corporate debt securities	9,478,123	3,695	9,481,818
Total securities	$ 10,469,519	$ 4,077	$ 10,473,596

Note 6 - Newly Issued Accounting Standards

In June 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issue Task Force ("EITF") Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in Restructuring)." This statement requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF No. 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. The Company does not have any pending or planned exit or disposal activities and does not expect a material effect on its financial position or results of operations from the adoption of this statement.

In April 2002 the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS No. 145 requires that gains and losses from extinguishment of debt be evaluated under the provisions of Accounting Principles Board Opinion No. 30 and be classified as ordinary items unless they are unusual or infrequent or meet the specific criteria for treatment as an extraordinary item. This statement is effective January 1, 2003. The Company does not anticipate that the adoption of this statement will have a material effect on its financial position or results of operations.

On January 1, 2002, the Company adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." There was no impact on the Company's financial position or results of operations as a result of the adoption of this statement.

In June 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires companies to recognize the fair value of an asset retirement liability in the financial statements by capitalizing that cost as part of the cost of the related long-lived asset. The asset retirement liability should then be allocated to expense by using a systematic and rational method. The statement is effective January 1, 2003. The Company has not yet determined the impact of adoption of this statement.

On January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets." There was no impact on the Company's financial position or results of operations as a result of the adoption of this statement.

Note 7 - Subsequent Events

On October 1, 2002, the Company entered into a Purchase and Sale Agreement with Burlington Resources Oil & Gas Company LP to acquire an estimated 61 BCFE of proved reserves for $76.4 million in cash. The properties are in the Williston Basin of Montana and North Dakota. The effective date of the acquisition will be July 1, 2002, and the transaction is expected to close in December 2002.

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

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 management forecasts, expects, believes or anticipates will or may occur in the future are forward-looking statements. 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 in 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, production rates and reserve replacement, 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, completion of pending acquisition transactions, competition, litigation, environmental matters, the potential impact of government regulations, and other matters discussed under the "Risk Factors" section of our 2001 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.

Overview

When comparing the nine months ended September 30, 2002, to activity in 2001 the focus will be on natural gas prices. Prices decreased compared to last year but were higher this quarter than they were in the first six months of 2002. We anticipate that the current historically strong prices for both natural gas and oil will continue through the end of the year and into 2003. Lease operating expense remained lower than in 2001 for both the quarter and the nine-month period. General and administrative expense on a per MCFE basis rose during the quarter but remained flat for the nine-months. In October 2002 we signed a purchase and sale agreement with Burlington Resources Oil & Gas Company LP to acquire an estimated 61 BCFE of proved reserves for $76.4 million in cash. This purchase is expected to close in December 2002.

Critical Accounting Policies and Estimates

We refer you to the corresponding section of our Annual Report on Form 10-K for the year ended December 31, 2001.

Results of Operations

The following table sets forth selected operating data for the periods indicated:

	Three Months Ended September 30, 2002	Three Months Ended September 30, 2001	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
	(In thousands, except per volume data)			
Oil and gas production revenues:				
Gas production	$ 27,103	$ 27,044	$ 80,837	$120,394
Oil production	18,018	14,815	51,574	44,801
Total	$ 45,121	$ 41,859	$132,411	$165,195
Net production:				
Gas (Mcf)	9,111	9,754	28,283	29,404
Oil (Bbls)	679	609	2,057	1,812
MCFE	13,186	3,405	40,625	40,274
Average sales price (1):				
Gas (per Mcf)	$ 2.97	$ 2.77	$ 2.86	$ 4.09
Oil (per Bbl)	$ 26.54	$ 24.35	$ 25.07	$ 24.73
Oil and gas production costs:				
Lease operating expense	$ 9,021	$ 11,441	$ 27,647	$ 28,805
Transportation costs	790	601	2,367	9,705
Production taxes	2,581	2,714	7,939	
Total	$ 12,392	$ 14,756	$ 37,953	$ 40,249
Additional per MCFE data:				
Sales price	$ 3.42	$ 3.12	$ 3.26	$ 4.10
Lease operating expense	0.68	0.85	0.68	0.72
Transportation costs	0.06	0.04	0.06	0.04
Production taxes	0.20	0.20	0.19	0.24
Operating margin	$ 2.48	$ 2.03	$ 2.33	$ 3.10
Depletion, depreciation and amortization	$ 0.97	$ 1.02	$ 0.96	$ 0.94
Impairment of proved properties	$ -	$ 0.04	$ -	$ 0.02
General and administrative	$ 0.33	$ 0.21	$ 0.26	$ 0.26

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(1) Includes the effects of St. Mary's hedging activities.

Three-Month Comparison

Oil and Gas Production Revenues. Our quarterly oil and gas production revenues increased $3.3 million or 8% to $45.1 million for the three months ended September 30, 2002 compared with $41.9 million for the same period in 2001. The following table presents the components of increases or (decreases) between 2002 and 2001:

	Production % Change	Price $ Change	Price % Change
o Natural Gas	(7 %)	$0.20/Mcf	7 %
o Oil	11 %	$2.19/Bbl	9 %

Average net daily production decreased slightly to 143.3 MMCFE for 2002 compared with 145.7 MMCFE in 2001. Our acquisition of properties from Choctaw in November 2001 added $3.6 million of revenue and average net daily production of 11.8 MMCFE to the three months ended September 30, 2002. Other acquisitions and wells completed during 2002 added average net daily production of 17.0 MMCFE. These increases helped to offset declines in average net daily production from older properties that include an average 8.5 MMCFE/day decline at Judge Digby.

We hedged approximately 55% or 376 MBbls of our oil production for the three months ended September 30, 2002, and realized a $167,000 decrease in oil revenue attributable to hedging compared with a $460,000 decrease in 2001. Without these contracts we would have received an average price of $26.78 per Bbl in the third quarter of 2002 compared to $25.11 per Bbl in 2001. We also hedged 47% of our 2002 third quarter gas production or 4.8 million MMBtu and realized a $560,000 decrease in gas revenue from hedging compared with a $187,000 increase in 2001. Without these contracts we would have received an average price of $3.04 per Mcf for the three months ended September 30, 2002 compared to $2.75 per Mcf for the same period in 2001.

Marketed Gas Revenue and Expense. As a result of our acquisition of gas gathering system lines in Coal County, Oklahoma in February 2002 we began taking title to and marketing natural gas for third parties. For the three months ended September 30, 2002, we received $3.4 million from the sale of this natural gas. Operating costs associated with these revenues totaled $3.5 million and resulted in a negative gross margin to us of $179,000. Due to pipeline imbalances, cost inflation and fluctuations in natural gas prices we may not always have a positive gross margin from gas marketing activities.

Oil and Gas Production Costs. Total production costs decreased $2.4 million or 16% to $12.4 million for the three months ended September 30, 2002 from $14.8 million in 2001. In the third quarter of 2002 our Gulf Coast region experienced a $2.2 million decrease in LOE reflecting decreased workover expense. Other core areas combined reflect an additional $1.1 million decrease in LOE that also reflects decreased workover expense. These decreases were offset by activity from our acquisition of properties from Choctaw that added $1.2 million of LOE in the third quarter of 2002 that was not reflected in 2001.

Total oil and gas production costs per MCFE decreased 15% to $0.94 for the three months ended September 30, 2002, compared with $1.10 for 2001. The decrease is comprised of the following:

- A $0.25 per MCFE decrease due to company-wide decreases in workover expense between the comparative quarters.
- A $0.08 per MCFE increase caused by increased activity in the higher-cost Williston Basin.
- A $0.02 increase in transportation costs.

Depreciation, Depletion, Amortization and Impairment. DD&A decreased $868,000 or 6% to $12.8 million for the three months ended September 30, 2002, from $13.7 million in 2001. DD&A per MCFE decreased by 5% to $0.97 for the third quarter of 2002 compared with $1.02 in 2001. DD&A per MCFE is affected by changes in estimated reserve quantities. At the end of each quarter we adjust our most recent engineered reserve estimate for anticipated production, new well additions and changes in oil and gas prices from the date of that estimate to the end of the quarter. Adjustments to economic quantities of reserves resulting from lower pricing at September 30, 2001, caused a large per MCFE increase in the third quarter of 2001 while higher pricing at September 30, 2002, caused a per MCFE decrease for the third quarter of 2002.

Exploration. Exploration expense decreased $128,000 or 3% to $4.2 million for the three months ended September 30, 2002, compared with $4.3 million in 2001. Percentages of total exploration expense are as follows:

	2002	2001
o Geological and geophysical expenses	20%	27%
o Exploratory dry holes	28%	31%
o Overhead and other expenses	52%	42%

General and Administrative. General and administrative expenses increased $1.6 million or 56% to $4.4 million for the three months ended September 30, 2002, compared with $2.8 million in 2001. Increases in compensation expense associated with increased personnel, our incentive plans and general cost inflation were partially offset by a $334,000 increase in COPAS overhead reimbursement from operations.

Interest Expense. Interest expense increased to $1.1 million for the quarter ended September 30, 2002. This amount reflects accrued interest on our senior convertible notes and will increase significantly on a comparative basis with last year as we accrue and pay the interest due on the notes. The amount we accrue and pay is affected by the fixed-rate to floating-rate interest rate swap we entered into in March 2002. Without this swap interest expense for the quarter ended September 30, 2002, would have been $1.6 million.

Income Taxes. Income tax expense totaled $4.2 million for the three months ended September 30, 2002, and $734,000 in 2001, resulting in effective tax rates of 35.4% and 13.1%, respectively. The difference in rates between the two periods reflects the cumulative effect on temporary differences in the quarter ended September 30, 2001 for changes to estimates of percentage depletion and our state income tax rate based on tax filings completed in that quarter.

Net Income. Net income for the three months ended September 30, 2002, increased $2.8 million or 58% to $7.7 million compared with $4.9 million in 2001. An 8% increase in oil and gas revenue combined with an unrealized derivative gain of $2.6 million, decreased oil and gas production costs and increased general and administrative expense resulted in an increase to net income before income tax of $6.7 million for the third quarter of 2002 compared with the third quarter of 2001. Income tax expense for the third quarter of 2002 is higher by $3.5 million due to a $2.2 million effect of applying the current rate to the increase in net income and due to a $1.3 million effect from the difference in income tax rates between the quarters.

Nine-Month Comparison

Oil and Gas Production Revenues. We experienced a decrease in oil and gas production revenues of $32.8 million, or 20% to $132.4 million for the nine months ended September 30, 2002, compared with $165.2 million for the same period in 2001. The following table presents the components of increases (decreases) between 2002 and 2001:

	Production % Change	Price $ Change	Price % Change
o Natural Gas	(4%)	($1.24)/Mcf	(30%)
o Oil	14%	$0.34/Bbl	1%

Average net daily production increased slightly to 148.8 MMCFE for the first nine months of 2002 compared with 147.5 MMCFE in 2001. Our acquisition of properties from Choctaw in November 2001 added $10.5 million of revenue and average net daily production of 12.0 MMCFE to the first nine months of 2002. Other acquisitions and wells completed during 2002 added average net daily production of 13.3 MMCFE. These increases offset declines in average net daily production from older properties that include an average 4.2 MMCFE/day decline at Judge Digby.

We hedged approximately 45% or 917 MBbls of our oil production for the nine months ended September 30, 2002, and realized a $2.4 million increase in oil revenue attributable to hedging compared with a $2.3 million decrease in oil revenue in 2001. Without these contracts we would have received an average price of $23.89 per Bbl for the nine months ended September 30, 2002, compared to $26.02 per Bbl in 2001. We also hedged 44% of our gas production or 13.8 million MMBtu and realized a $344,000 increase in gas revenue for the nine months ended September 30, 2002, compared with a $20.3 million decrease in gas revenue in 2001. Without these contracts we would have received an average price of $2.85 per Mcf for the nine months ended September 30, 2002, compared to $4.78 per Mcf for the same period in 2001.

Marketed Gas Revenue and Expense. For the nine months ended September 30, 2002, we received $6.8 million from the sale of this natural gas. Costs associated with these revenues totaled $6.6 million and resulted in gross margin to us of $179,000.

Oil and Gas Production Costs. Total production costs decreased $2.3 million or 6% to $38.0 million for the nine months ended September 30, 2002, from $40.2 million in 2001. In the second quarter of 2002 our Gulf Coast region experienced a $2.7 million decrease in LOE that was comprised of a decrease in workover expense and an adjustment due to the issuance of a revised Authorization For Expenditure by the Operator at Judge Digby. This AFE indicated that workover LOE we previously expensed under the original AFE should be recorded as property, plant and equipment. In the third quarter of 2002 we experienced a $3.3 million decrease in LOE due to more decreases in workover expense. This decrease was offset by a $1.4 million general inflation increase we expected and activity from our acquisition of properties from Choctaw that added $4.2 million of LOE in 2002 that was not reflected in 2001. The $1.8 million decrease in production taxes reflects the decrease in revenue discussed above.

Total oil and gas production costs per MCFE decreased 7% to $0.93 for the nine months ended September 30, 2002, compared with $1.00 for 2001. This decrease is comprised of the following:

- A $0.05 per MCFE decrease in production taxes due to lower per MCFE prices.
- A $0.19 per MCFE decrease in LOE attributable to decreases in workover expense in the Gulf Coast and Permian regions in excess of general cost inflation increases.
- A $0.01 per MCFE increase in LOE attributable to general cost inflation increases in excess of decreases in workover expense in the Mid-Continent and ArkLaTex regions.
- A $0.14 per MCFE increase in LOE attributable to increased activity in the higher cost Williston Basin.

Although we continue to monitor these costs, we believe that the trend of decreases in LOE on an absolute basis and on a per MCFE basis will not continue into the future. New workover activity is always a possibility in our Gulf Coast region and it is likely that future acquisitions of producing properties in the Williston Basin will lead to additional workover activities as we attempt to enhance the performance and lengthen the lives of those properties.

Depreciation, Depletion, Amortization and Impairment. DD&A increased $1.3 million or 3% to $39.2 million for the nine months ended September 30, 2002, from $37.9 million in 2001. This increase reflects both the increase in production between the respective periods for 2002 and 2001 and acquisitions and drilling results from both years that caused DD&A per MCFE to increase by 3% to $0.96 in 2002 compared with $0.94 in 2001.

Exploration. Exploration expense increased $574,000 or 4% to $15.4 million for the nine months ended September 30, 2002, compared with $14.9 million in 2001. Percentages of total exploration expense are as follows:

	2002	2001
o Geological and geophysical expenses	14%	23%
o Exploratory dry holes	47%	39%
o Overhead and other expenses	39%	38%

General and Administrative. General and administrative expenses increased

$183,000 to $10.5 million for the nine months ended September 30, 2002, compared with $10.4 million in 2001. Increases in compensation expense associated with increased personnel, our incentive plans and general cost inflation were partially offset by a $1.2 million increase in COPAS overhead reimbursement from operations and costs allocated to exploration expense. We anticipate that general and administrative expense on a per MCFE basis will be 10% to 20% higher for the entire year of 2002 than it was for the entire year of 2001.

Interest Expense. Interest expense increased to $2.6 million for the nine months ended September 30, 2002. This amount reflects accrued interest on our senior convertible notes and will increase significantly on a comparative basis with last year as we accrue and pay the interest due on the notes in 2002. The amount we accrue and pay is affected by the fixed-rate to floating-rate interest rate swap we entered into in March 2002. Without this swap interest expense for the period ending September 30, 2002, would have been $3.3 million.

Income Taxes. Income tax expense totaled $10.6 million for the nine months ended September 30, 2002, and $21.1 million in 2001, resulting in effective tax rates of 34% and 34.8%, respectively. This decrease is a result of the tax effect of interest expense on convertible debt with contingent interest provisions combined with a lesser effect of state income taxes and an increase in the effect of Section 29 credits on a lesser net income in 2002.

Net Income. Net income for the nine months ended September 30, 2002, decreased $18.9 million to $20.6 million compared with $39.5 million in 2001. A 30% decrease in gas prices and a 4% decrease in gas production offset in part by a 14% increase in oil production resulted in a $32.8 million decrease in oil and gas production revenue between the two periods. This decrease caused a corresponding and partially offsetting decrease of $10.5 million in income tax expense. We also had $4.6 million of unrealized derivative gain that helped to offset a portion of the difference.

Liquidity and Capital Resources

Our primary sources of liquidity are the cash provided by operating activities, debt financing, sales of non-strategic properties and access to the capital markets. All of these sources can be impacted by significant fluctuation in oil and gas prices. An unexpected decrease in prices would reduce expected cash flow from operating activities, might reduce the borrowing base on our credit facility, could reduce the value of our non-strategic properties and historically has limited our industry's access to the capital markets.

We use cash for the acquisition, exploration and development of oil and gas properties and for the payment of debt obligations, trade payables and stockholder dividends. Exploration and development programs are generally financed from internally generated cash flow, debt financing and cash and cash equivalents on hand. In the event of an unexpected decrease in oil and gas prices, cash uses such as the acquisition of oil and gas properties and the payment of stockholder dividends are discretionary and can be reduced or eliminated. At any given point in time, we may be obligated to pay for commitments to explore for or develop oil and gas properties or incur trade payables. However, future obligations can be reduced or eliminated when necessary. We are currently only required to make interest payments on our debt obligations. An unexpected increase in oil and gas prices provides flexibility to modify our uses of cash flow.

We continually review our capital expenditure budget to reflect changes in current and projected cash flow, acquisition opportunities, debt requirements and other factors.

Cash Flow. Net cash provided by operating activities decreased $5.7 million or 5% to $106.2 million for the nine months ended September 30, 2002, compared with $111.9 million in 2001. The decrease reflects the effect of lower gas production revenues and the effect on deferred income tax expense of a reduced exploration and development capital expenditures budget in 2002. This decrease was offset by changes in current assets and liabilities of $25.9 million.

Net cash used in investing activities increased $1.1 million to $93.8 million for the nine months ended September 30, 2002, compared with $92.7 million in 2001. This increase is due to our net $10.5 million short-term investment in this quarter and a net $5.6 million decrease in sales proceeds between the two periods offset by a $14.8 million decrease in capital expenditures. Total capital expenditures, including acquisitions of oil and gas properties, in the first nine months of 2002 decreased 15% to $86.7 million compared with $101.5 million in the first nine months of 2001.

Net cash provided by financing activities increased $52.2 million to $32.7 million for the nine months ended September 30, 2002, compared with cash used in financing activities of $19.5 million in 2001. This increase reflects our March 2002 private placement of $100.0 million of 5.75% senior convertible notes due 2022. A portion of the net proceeds of $96.7 million was used to repay the balance due on the credit facility. We have not repurchased any common stock in the first nine months of 2002.

St. Mary had $49.1 million in cash and cash equivalents and had working capital of $40.4 million as of September 30, 2002, compared with $4.1 million in cash and cash equivalents and working capital of $34.0 million at December 31, 2001. The increase in cash and cash equivalents reflects our issuance of $100.0 million of senior convertible notes during the first quarter of 2002.

Senior Convertible Notes. In March 2002 we issued in a private placement a total of $100.0 million of 5.75% senior convertible notes due 2022 with a 0.5% contingent interest provision. The contingent interest provision did not apply to our first interest payment on September 15, 2002, but it will apply to the payment due on March 15, 2003. Interest payments on the notes will be made on March 15 and September 15 in subsequent years. We received net proceeds of $96.7 million after deducting the initial purchasers' discount and estimated offering expenses payable by us. The notes are general unsecured obligations and rank on parity in right of payment with all our existing and future unsecured senior indebtedness and other general unsecured obligations, and are senior in right of payment to all our future subordinated indebtedness. The notes are convertible into our common stock at a conversion price of $26.00 per share, subject to adjustment. We can redeem the notes with cash in whole or in part at a repurchase price of 100% of the principal amount plus accrued and unpaid interest including contingent interest beginning on March 20, 2007. The note holders have the option of requiring us to repurchase the notes for cash at 100% of the principal amount plus accrued and unpaid interest including contingent interest upon (1) a change in control of St. Mary or (2) on March 20, 2007, March 15, 2012, and March 15, 2017. If the note holders require repurchase on March 20, 2007, we may pay the repurchase price with cash, shares of our common stock valued at a discount to the market price at the time of repurchase or any combination of cash and our discounted common stock. We are not restricted from paying dividends, incurring debt, or issuing or repurchasing our securities under the indenture for the notes. There are no financial covenants in the indenture. We used a portion of the net proceeds from the notes to repay our credit facility balance and will use the remaining net proceeds to fund a portion of our 2002 capital budget. On March 25, 2002, we entered into a five-year fixed-rate to floating-rate interest rate swap on $50.0 million of the notes. The floating rate for each applicable six-month period will be determined as LIBOR plus 0.36%. For the current calculation period this rate is 2.19%.

Credit Facility. The maximum loan amount under our long-term revolving credit facility is $200.0 million. The amount actually available depends upon a borrowing base that the lenders periodically redetermine based on the value of our oil and gas properties and other assets. Since we pay commitment fees based on the unused portion of the borrowing base, we have generally limited the borrowing base that we have accepted to correspond to our actual funding requirements. On April 10, 2002, the stated total possible borrowing base was reduced by $10.0 million to $160.0 million, and the accepted borrowing base was reduced by $60.0 million to $40.0 million. The facility has a maturity date of December 31, 2006, and includes a revolving period that matures on June 30, 2003, at which time all outstanding borrowings convert to a term loan payable in quarterly installments through the facility maturity date. We must comply with certain covenants including maintenance of stockholders' equity at a specified level, restrictions on additional indebtedness, sales of oil and gas properties, activities outside our ordinary course of business and certain merger transactions. Borrowings under the facility are secured by a pledge of collateral in favor of the banks and guarantees by subsidiaries. Such collateral consists primarily of security interests in the oil and gas properties of St. Mary and its subsidiaries.

As of September 30, 2002, we had no balance outstanding under this credit agreement compared to $64.0 million at December 31, 2001. Pursuant to a March 4, 2002, amendment to the credit agreement, during the revolving period of the loan, loan balances will accrue interest at our option of either (1) the higher of the federal funds rate plus 0.5% or the prime rate, plus an additional 0.25% when our debt to capitalization ratio is greater than 50%, or (2) the LIBOR rate plus (a) 1% when our debt to total capitalization ratio is less than 30%, (b) 1.25 % when our debt to capitalization ratio is greater than or equal to 30% but less than 40%, (c) 1.375% when our debt to capitalization ratio is greater than or equal to 40% but less than 50%, or (d) 1.625% when our debt to capitalization ratio is greater than 50%. Our debt to capitalization ratio as defined under the credit agreement was 25% as of September 30, 2002.

Schedule of Contractual Obligations. The following table summarizes our future estimated principal payments for the periods specified (in millions):

Contractual Obligations	Long-Term Debt	Operating Leases	Total Cash Obligation
Less than 1 year	$ -	$1.1	$ 1.1
1-3 years	-	1.7	1.7
4-5 years	-	1.4	1.4
After 5 years	100.0	3.0	103.0
Total	$100.0	$7.2	$107.2

In the period from 1-3 years, we have two leases of office space for our regional offices that will expire. A third lease for office space will expire in year 4. 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 senior convertible notes will not exercise the conversion feature.

Common Stock. In August 1998 St. Mary's board of directors authorized a stock repurchase program whereby we may purchase from time-to-time, in open market transactions or negotiated sales, up to two million of our common shares.

Through September 30, 2002, we have repurchased a cumulative total of 1,009,900 shares of St. Mary's common stock under the program for $16.2 million at a weighted average price of $15.86 per share, net of put option sale premiums received. We anticipate that additional purchases of shares may occur as market conditions warrant. Any future purchases will be funded with internal cash flow and borrowings under St. Mary's credit facility.

Capital and Exploration Expenditures Incurred. St. Mary's expenditures for exploration and development of oil and gas properties and acquisitions are the primary use of its capital resources. The following table sets forth certain information regarding the costs incurred by St. Mary in its oil and gas activities during the periods indicated:

	Capital and Exploration Expenditures	
	Nine Months Ended September 30,	
	2002	2001
	(In thousands)	
Development	$ 52,584	$ 74,346
Domestic Exploration	12,704	18,451
Acquisitions:		
Proved	7,886	3,819
Unproved	10,582	18,188
Total	$ 83,756	$ 114,804

We continuously evaluate opportunities in the marketplace for oil and gas properties and, accordingly, may be a buyer or a seller of properties at various times. We will continue to emphasize smaller niche acquisitions utilizing St. Mary's technical expertise, financial flexibility and structuring experience. In addition, we are actively seeking larger acquisitions of assets or companies that would afford opportunities to expand our existing core areas, add geoscientists and/or engineers, or gain a significant acreage and production foothold in a new basin.

St. Mary's total costs incurred for capital and exploration activities in the first nine months of 2002 decreased $28.0 million or 24% compared to the first nine months of 2001. We spent $75.9 million in the first nine months of

2002 for unproved property acquisitions and domestic exploration and development compared to $111.0 million for the comparable period in 2001. This decrease was a result of planned decreases in the drilling activity budget and a $7.6 million decrease in unproved property acquisition activity. Well testing continues on our two coalbed methane pilot programs located on fee acreage in the Hanging Woman Basin. All wells are currently shut-in while we evaluate the data from dewatering. Prior to shut-in, production from the Anderson coal averaged 250 Mcf/day. During the year, one of our partners exercised their right to participate in a leasehold acquisition bringing our total to 123,000 net acres in the project. We are subject to an environmental public interest group lawsuit on 46,000 of these acres. See "Legal Proceedings" for a discussion of this lawsuit.

On April 26, 2002, the Interior Board of Land Appeals of the U.S. Department of the Interior issued an order that reversed a decision by the U.S. Bureau of Land Management dismissing a protest by the Wyoming Outdoor Council and Powder River Basin Resource Council of the offer for sale in February 2000 of three oil and gas leases in the Powder River Basin in Wyoming. The Board held that the BLM determination to allow the offer for sale of the three particular leases did not comply with environmental laws since the environmental analysis used by the BLM in making that determination did not contain a discussion of the unique potential impacts associated with coalbed methane extraction and development or consider reasonable alternatives relevant to a pre-leasing environmental analysis. On October 15, 2002, the Board refused to reconsider this holding period. The order addressed only three particular leases covering approximately 2,600 acres that are not included in our Hanging Woman Basin project. However, we cannot assure you that other leases, including issued leases that we hold in the Hanging Woman Basin, will not be challenged on a similar basis.

In November 2001 we purchased oil and gas properties from Choctaw II Oil & Gas, Ltd. for $40.5 million in cash. We used a portion of our credit facility for this acquisition. The properties are primarily located in the Williston Basin of Montana and North Dakota and in the Green River Basin of Wyoming.

On October 2, 2002, we signed a purchase and sale agreement with Burlington Resources Oil & Gas Company LP to acquire oil and gas properties in the Williston Basin of Montana and North Dakota for $76.4 million in cash. The effective date of this acquisition is July 1, 2002. We intend to finance this acquisition using cash on hand and our bank credit facility. These properties currently produce an estimated 3.1 MBbls of oil per day and 3.3 MMcf of natural gas per day. This transaction is expected to close December 3, 2002, upon completion of customary due diligence.

Capital Expenditure Budget. We anticipate spending approximately $189 million for capital and exploration expenditures in 2002 with $104 million allocated for ongoing exploration and development and $85 million for acquisitions of producing properties. Anticipated ongoing exploration and development expenditures for each of St. Mary's core areas is as follows (in millions):

o Mid-Continent region	$ 42
o Gulf Coast and Gulf of Mexico region	20
o ArkLaTex region	12
o Williston Basin	18
o Permian Basin and other	6
o Other	6
Total	$ 104

We believe the amount not funded from our internally generated cash flow in 2002 can be funded from our existing cash and our credit facility. The amount and allocation of future capital and exploration expenditures will depend upon a number of factors including the number and size of available acquisition opportunities and our ability to assimilate these acquisitions. Also, the impact of oil and gas prices on investment opportunities, the availability of capital

and borrowing capability and the success of our development and exploratory activity could lead to funding requirements for further development. If additional development or attractive acquisition opportunities arise, we may consider other forms of financing, including the public offering or private placement of equity or debt securities.

We seek to protect our rate of return on acquisitions of producing properties by hedging cash flow when the economic criteria from its evaluation and pricing model indicate it would be appropriate. Management's strategy is to hedge cash flows from investments requiring a gas price in excess of $3.25 per Mcf and an oil price in excess of $22.50 per Bbl in order to meet minimum rate-of-return criteria. We anticipate this strategy will result in the hedging of future cash flow from acquisitions. We generally limit St. Mary's aggregate hedge position to no more than 35% of total production but will hedge larger percentages of total production in certain circumstances. We seek to minimize basis risk and index the majority of oil hedges to NYMEX prices and the majority of gas hedges to various regional index prices associated with pipelines in proximity to our areas of gas production. Including hedges entered into since September 30, 2002 we have hedged as follows:

Swaps:

Product	Average Volumes/month	Quantity Type	Average Fixed price	Duration
Natural Gas	1,696,000	MMBtu	$2.87	10/02 - 12/02
Natural Gas	565,000	MMBtu	$3.38	01/03 - 12/03
Natural Gas	299,000	MMBtu	$3.66	01/04 - 12/04
Oil	200,300	Bbls	$27.07	10/02 - 12/02
Oil	146,500	Bbls	$24.88	01/03 - 12/03
Oil	65,500	Bbls	$23.80	01/04 - 12/04

On February 4, 2002, we entered into an agreement to monetize our unrealized hedge gain receivable due from Enron for $1.1 million. This amount was included in other comprehensive income at December 31, 2001, and was recorded as a hedge gain in the first quarter of 2002. Hedge gains and losses are reported in oil and gas production revenues in our consolidated statements of operations. Amortization of $1.2 million of other comprehensive income related to our commodity positions with Enron is also recorded in hedge gain. Additional amortization will be recorded in hedge gain in future months. Unrealized derivative gain in the consolidated statements of operations includes $4,000 of net loss from oil and gas hedge ineffectiveness.

Our senior convertible notes contain a provision for payment of contingent interest if certain conditions are met. Under Statement of Financial Accounting Standards No. 133 this provision 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 separated and accounted for as a derivative instrument. The value of the derivative at issuance was $474,000. This amount was recorded as a decrease to the convertible notes payable in the consolidated balance sheets. Of this amount, $51,000 has been amortized through interest expense. Unrealized derivative gain in the consolidated statements of operations includes $239,000 of net loss from mark-to-market adjustments for this derivative.

Our fixed-rate to floating-rate interest rate swap on $50.0 million of senior convertible notes did not qualify for fair value hedge treatment under SFAS No. 133. Unrealized derivative gain in the consolidated statements of operations includes $4.8 million of net gain from mark-to-market adjustments for this derivative.

We anticipate that all hedge transactions will occur as expected.

Accounting Matters

New Accounting Standards

In June 2002 the Financial Accounting Standards Board ("FASB") issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." This statement addresses financial accounting and reporting for costs associated with exit or disposal activities and requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. We do not have any pending or planned exit or disposal activities and do not expect a material effect on our financial position or results of operations from the adoption of this statement.

In April 2002 the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS No. 145 requires that gains and losses from extinguishment of debt be evaluated under the provisions of Accounting Principles Board Opinion No. 30 and be classified as ordinary items unless they are unusual or infrequent or meet the specific criteria for treatment as an extraordinary item. This statement is effective for fiscal years beginning after May 15, 2002. We do not anticipate that the adoption of this statement will have a material effect on our financial position or results of operations.

In June 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." This statement requires companies to recognize the fair value of an asset retirement liability in the financial statements by capitalizing that cost as part of the cost of the related long-lived asset. The asset retirement liability should then be allocated to expense by using a systematic and rational method. The statement is effective January 1, 2003. We have not determined the impact of adoption of this statement.

Compensation Expense

We have a net profits interest incentive bonus plan for key employees designated as participants by our board of directors. Under the plan oil and gas wells that are completed or acquired during a year are designated as a pool. Participants employed by us on the last day of that year vest and become entitled to bonus payments after we recover net revenues generated by the pool equal to 100% of our investment in that pool. Thereafter an amount generally equal to10% of net revenues generated by the pool will be split among the participants and paid on a quarterly basis. The percentage of net revenues from the pool to be split among the participants increases to 20% after we recover net revenues equal to 200% of our investment.

The estimated compensation expense will be based on a number of assumptions including estimates of oil and gas production, oil and gas prices, recurring and lease operating expense and a present value discount factor. We use a discount factor to calculate present value that reflects recovery of our investment, the timing of payments to participants and uncertainties associated with our estimates. The estimates we use will change from year-to-year based on new information and any change in estimated compensation will be recorded in the period that information becomes available.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We hold derivative contracts and financial instruments that have cash flow and net income exposure to changes in commodity prices or interest rates. Financial and commodity-based derivative contracts are used to limit the risks inherent in some crude oil and natural gas price changes that have an effect on us.

Our board of directors has adopted a policy regarding the use of derivative instruments. This policy requires every derivative used by St. Mary to relate to underlying offsetting positions, anticipated transactions or firm commitments. It prohibits the use of speculative, highly complex or leveraged derivatives. Under the policy, the Chief Executive Officer and Vice-President - Finance must review and approve all risk management programs that use derivatives. The board of directors and the audit committee periodically review these programs.

Commodity Price Risk. We use various hedging arrangements to manage our exposure to price risk from natural gas and crude oil production. These hedging arrangements have the effect of locking in for specified periods, at predetermined prices or ranges of prices, the prices we will receive for the volumes to which the hedge relates. Consequently, while these hedging arrangements are structured to reduce our exposure to decreases in prices associated with the hedged commodity, they also limit the benefit we might otherwise receive from any price increases associated with the hedged commodity. The derivative gain or loss effectively offsets the loss or gain on the underlying commodity exposures that have been hedged. The fair values of the swaps are estimated based on quoted market prices of comparable contracts and approximate the net gains or losses that would have been realized if the contracts had been closed out at quarter-end. The fair values of the futures are based on quoted market prices obtained from the New York Mercantile Exchange.

A hypothetical $0.10 per MMBtu change in St. Mary's quarter-end market prices for natural gas swaps and futures contracts on a notional amount of 15.5 million MMBtu would cause a potential $1.1 million change in net income before income taxes for contracts in place on September 30, 2002. A hypothetical $1.00

per Bbl change in our quarter-end market prices for crude oil swaps and future contracts on a notional amount of 3.1 MMBbls would cause a potential $2.9 million change in net income before income taxes for oil contracts in place on September 30, 2002. These hypothetical changes were discounted to present value using a 7.5% discount rate since the latest expected maturity date of certain swaps and futures contracts is greater than one year from the reporting date.

Interest Rate Risk. 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. A sensitivity analysis presents the hypothetical change in fair value of those financial instruments held by St. Mary at September 30, 2002, that are sensitive to changes in interest rates. For fixed-rate debt, interest rate changes affect the fair market value but do not impact results of operations or cash flows. Conversely for floating rate debt, interest rate changes 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. We had floating rate debt of $50.0 million and fixed rate debt of $50.0 million at September 30, 2002. Assuming constant debt levels, the impact on results of operations and cash flows for the remainder of the year resulting from a one-percentage-point change in interest rates would be approximately $125,000 before taxes.

ITEM 4. CONTROLS AND PROCEDURES

We maintain a system of disclosure controls and procedures that are designed for the purposes of ensuring 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 Vice-President - Finance, as appropriate to allow timely decisions regarding required disclosure.

Within the 90-day period prior to the filing of this report, we carried out an evaluation, under the supervision and with the participation of our management, including the Chief Executive Officer and the Vice-President - Finance, of the effectiveness of the design and operation of our disclosure controls and procedures. Based upon that evaluation, the Chief Executive Officer and the Vice-President - Finance concluded that our disclosure controls and procedures are effective for the purposes discussed above. There have been no significant changes in our internal controls or in other factors that could significantly affect these controls subsequent to the date of their evaluation.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

On March 27, 2002, Nance Petroleum Corporation, a wholly owned subsidiary, was named along with several other leaseholders and interested parties as an additional co-defendant in a lawsuit that was originally filed in the U.S. District Court for the District of Montana on June 12, 2001. The plaintiff, the Northern Plains Resource Council, Inc. ("NPRC"), an environmental public interest group, sued the U.S. Bureau of Land Management, the U.S. Secretary of the Interior, the Montana BLM State Director and Fidelity Exploration & Production Company. The lawsuit, which was reported in our 2001 Form 10-K and our first and second quarter 2002 Form 10-Qs, seeks the cancellation of all federal leases related to coalbed methane development in Montana issued by the BLM since January 1, 1997. This cancellation is sought primarily on the grounds of an alleged failure of the BLM to comply with federal environmental laws. NPRC alleges that the environmental impacts of coalbed methane development were not properly analyzed before the challenged leases were issued. The Montana portion of our Hanging Basin Woman coalbed methane project contains approximately 123,000 total net acres. The lawsuit potentially affects the approximately 46,000 net acres that are subject to federal leases. Based on information presently available, we believe that the BLM complied with the applicable environmental laws. Nevertheless, there is no assurance as to the outcome of the lawsuit, and therefore, there is no assurance that it will not adversely affect our coalbed methane project. Even if the federal leases in Montana become unavailable, we anticipate continuing with the Hanging Woman Basin project in Wyoming, and obtaining additional non-federal leases in Montana. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a discussion of other recent coalbed methane legal developments.

As previously reported in our first and second quarter 2002 Form 10-Qs, on May 1, 2002, GNK Acquisition Corp., a recently acquired wholly owned subsidiary, was served in a lawsuit that was filed earlier in 2002 in the District Court in Shelby County, Texas. This suit was filed by Samson Lone Star Limited Partnership against GNK Acquisition Corp. and GNK, Inc., the previous owner of GNK Acquisition Corp. The lawsuit primarily involves a claim related to certain oil and gas leasehold positions acquired by GNK Acquisition Corp. These leases were acquired by the exercise of a contractual preferential right to purchase. This right was triggered by the plaintiff in its attempt to acquire these same leasehold positions from the party that ultimately sold these positions to GNK Acquisition Corp. Samson alleges that it is entitled to acquire a portion of such lease

positions as a result of an agreement it had with GNK, Inc. An answer by GNK Acquisition Corp. to the underlying petition by Samson has been filed, and discovery has begun. Although the lawsuit is in a very preliminary stage and there can be no assurance of the ultimate outcome, we do not believe based on the information presently available that the lawsuit will have a material adverse effect on our financial condition or results of operations.

ITEM 5. Other Information

As previously reported in Part III, Item 13 of our Annual Report on Form 10-K/A No. 2 for the year ended December 31, 2001, St. Mary made an interest-free relocation loan of $200,000 to an executive officer in July 2000. The loan was due and payable in full upon the earlier of thirty days after a termination of employment or July 15, 2005. The loan was repaid in full in October 2002 and is no longer outstanding, notwithstanding the continued employment of the executive officer.

On October 31, 2002, the Audit Committee of the Board of Directors of St. Mary approved in advance certain non-audit services to be performed by Deloitte & Touche LLP, St. Mary's independent auditor. These non-audit services are to consist primarily of corporate tax compliance and tax consultation services.

ITEM 6. Exhibits and Reports on Form 8-K

(b) Reports on Form 8-K

St. Mary Land & Exploration Company filed the following current reports on Form 8-K during the quarter ended September 30, 2002:

On July 9, 2002, we filed a current report on Form 8-K reporting under Item 9 that we had issued a press release announcing an update of our operations for the second quarter of 2002 and an update of the 2002 forecast.

On August 8, 2002, we filed a current report on Form 8-K reporting under Item 9 that we had issued a press release announcing our earnings and financial highlights for the second quarter of 2002.

On August 8, 2002, we filed an amended current report on Form 8-K/A to include a conformed signature for the Form 8-K filed August 8, 2002. The conformed signature was inadvertently omitted from the originally filed Form 8-K.

On August 14, 2002, we filed a current report on Form 8-K reporting under Item 9 that in connection with the filing of the Form 10-Q, on August 14, 2002, the Chief Executive Officer and the Vice-President - Finance of the registrant each signed a Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

On August 28, 2002, we filed a current report on Form 8-K reporting under Item 9 that in connection with the filing of the amended Annual Report on Form 10-K/A No. 2, on August 28, 2002, the Chief Executive Officer and the Vice-President - Finance of the registrant each signed a Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

On September 24, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing the retirement of Thomas E. Congdon as Board Chairman.

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 13, 2002

By /s/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chairman of the Board, President

and Chief Executive Officer

November 13, 2002	By	/s/ RICHARD C. NORRIS -------------------------------- Richard C. Norris Vice-President - Finance, Secretary and Treasurer
November 13, 2002	By	/s/ GARRY A. WILKENING -------------------------------- Garry A. Wilkening Vice-President - Administration and Controller

CERTIFICATION

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 13, 2002

/s/ MARK A. HELLERSTEIN

Mark A. Hellerstein
Chairman of the Board, President and
Chief Executive Officer

CERTIFICATION

I, Richard C. Norris, 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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 13, 2002

/s/ RICHARD C. NORRIS

Richard C. Norris
Vice-President - Finance