CHESAPEAKE ENERGY CORP
Form 10-Q
May 15, 2002

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended March 31, 2002

[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from to

COMMISSION FILE NO. 1-13726

CHESAPEAKE ENERGY CORPORATION
(Exact Name of Registrant as Specified in Its Charter)

OKLAHOMA (State or other jurisdiction of incorporation or organization)	73-1395733 (I.R.S. Employer Identification No.)
6100 NORTH WESTERN AVENUE OKLAHOMA CITY, OKLAHOMA (Address of principal executive offices)	73118 (Zip Code)

(405) 848-8000
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 [ ]

At March 10, 2002, there were 165,935,028 shares of our $.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2002

PART I.

FINANCIAL INFORMATION

PART II.

OTHER INFORMATION

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	D
ASSETS	
CURRENT ASSETS:	
Cash and cash equivalents	$
Restricted cash	
Accounts receivable:	
Oil and gas sales	
Joint interest, net of allowances of $947,000 and $1,093,000, respectively	
Short-term derivatives	
Related parties	
Other	
Short-term derivative instruments	
Inventory and other	
Total Current Assets	
PROPERTY AND EQUIPMENT:	

Oil and gas properties, at cost based on full-cost accounting:	
Evaluated oil and gas properties	
Unevaluated properties	
Less: accumulated depreciation, depletion and amortization	(
	--
Other property and equipment	
Less: accumulated depreciation and amortization	
	--
Total Property and Equipment	
OTHER ASSETS:	
Long-term derivatives receivable	
Deferred income tax asset	
Long-term derivative instruments	
Long-term investments	
Other assets	
	--
Total Other Assets	
	--
TOTAL ASSETS	$
	==

LIABILITIES AND STOCKHOLDERS' EQUITY

CURRENT LIABILITIES:	
Notes payable and current maturities of long-term debt	$
Accounts payable	
Accrued interest	
Short-term derivative instruments	
Other accrued liabilities	
Revenues and royalties due others	
	--
Total Current Liabilities	
	--
LONG-TERM DEBT, NET	
	--
REVENUES AND ROYALTIES DUE OTHERS	
	--
LONG-TERM DERIVATIVE INSTRUMENTS	
	--
OTHER LIABILITIES	
	--
CONTINGENCIES AND COMMITMENTS (NOTE 3)	
STOCKHOLDERS' EQUITY:	
Preferred Stock, $.01 par value, 10,000,000 shares authorized; 3,000,000 shares of 6.75% cumulative convertible preferred stock, issued and outstanding at December 31, 2001 and March 31, 2002, entitled in liquidation to $150 million	
Common Stock, $.01 par value, 350,000,000 shares authorized, 169,534,991 and 170,588,773 shares issued at December 31, 2001 and March 31, 2002, respectively	
Paid-in capital	
Accumulated deficit	
Accumulated other comprehensive income, net of tax of $29,000,000 and $12,793,000, respectively	
Less: treasury stock, at cost; 4,792,529 common shares at December 31, 2001 and March 31, 2002	
	--

Total Stockholders' Equity	
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	THREE MONTHS ENDED MARCH 31,	
	2001	2002
	($ IN THOUSANDS, EXCEPT PER SHARE AMOUNTS)	
REVENUES:		
Oil and gas sales	$ 221,219	$ 141,97
Risk management loss	--	(79,46
Oil and gas marketing sales	56,165	27,33
Total Revenues	277,384	89,83
OPERATING COSTS:		
Production expenses	17,788	22,06
Production taxes	14,295	5,21
General and administrative	4,001	4,29
Oil and gas marketing expenses	54,478	26,50
Oil and gas depreciation, depletion and amortization	38,173	48,61
Depreciation and amortization of other assets	1,953	3,11
Total Operating Costs	130,688	109,80
INCOME (LOSS) FROM OPERATIONS	146,696	(19,97
OTHER INCOME (EXPENSE):		
Interest and other income	569	95
Interest expense	(25,889)	(26,96
Gothic standby credit facility costs	(3,392)	-
Total Other Income (Expense)	(28,712)	(26,00
INCOME (LOSS) BEFORE INCOME TAXES	117,984	(45,97
PROVISION (BENEFIT) FOR INCOME TAXES	47,696	(18,39
NET INCOME (LOSS)	70,288	(27,58
PREFERRED STOCK DIVIDENDS	(546)	(2,53
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 69,742	$ (30,11

EARNINGS (LOSS) PER COMMON SHARE:		
Basic	$ 0.44	$ (0.1
Assuming dilution	$ 0.41	$ (0.1
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING:		
Basic	157,707	165,37
Assuming dilution	170,326	165,37

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

	THREE MONTHS ENDED MARCH 31,	
	2001	2002
	($ IN THOUSANDS)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ 70,288	$ (27,58
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	39,116	50,52
Risk management loss	--	79,46
Deferred income taxes	47,696	(18,39
Write-off of credit facility cost	3,392	-
Amortization of loan costs	1,010	1,20
Amortization of bond discount	19	24
Accretion of Gothic note premium	(704)	-
Loss on sale/disposal of fixed assets and other	25	4
Loss on repurchase of debt	--	59
Gain on sale of RAM Energy notes	--	(46
Bad debt expense	--	14
Other	64	12
Cash provided by operating activities before changes in current assets and liabilities	160,906	85,91
Changes in assets and liabilities	45,443	31,38

Cash provided by operating activities	206,349	117,29
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of oil and gas properties	(109,859)	(83,28
Purchases of oil and gas properties	(43,980)	(89
Sales of oil and gas properties	140	-
Sales of non-oil and gas assets	35	3
Additions to buildings and other fixed assets	(13,060)	(7,41
Additions to drilling rig equipment	--	(21
Additions to long-term investments	--	(2,40
Proceeds from sale of RAM Energy notes	--	4,21
Other	269	
Cash used in investing activities	(166,455)	(89,95
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	93,000	-
Payments on long-term borrowings	(103,500)	-
Cash paid to repurchase senior notes	(8,255)	(21,00
Cash paid for premium on repurchase of senior notes	--	(44
Cash paid for financing costs related to debt	(712)	(8
Cash received from exercise of stock options	2,191	1,18
Cash paid for preferred stock dividend	(546)	(2,58
Other	--	(5
Cash used in financing activities	(17,822)	(22,98
Effect of changes in exchange rate on cash	(869)	-
NET INCREASE IN CASH AND CASH EQUIVALENTS	21,203	4,35
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	--	117,59
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 21,203	$ 121,95

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(UNAUDITED)

	THREE MONTHS E
	2001
	($ IN THO
Net income (loss)	$ 70,288

Other comprehensive income (loss), net of income tax:	
Foreign currency translation adjustments	(3,219)
Cumulative effect of accounting change for financial derivatives	(53,580)
Change in fair value of derivative instruments	42,138
Reclassification of settled contracts	18,326
Ineffective portion of derivatives qualifying for hedge accounting	--
Comprehensive income (loss)	$ 73,953

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
MARCH 31, 2002
(UNAUDITED)

1. BASIS OF PRESENTATION AND ACCOUNTING POLICIES

Principles of Consolidation

The accompanying unaudited consolidated financial statements of Chesapeake Energy Corporation and Subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair presentation of the results for the interim periods have been reflected. The results for the three months ended March 31, 2002 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three months ended March 31, 2001 (the "Prior Quarter") and the three months ended March 31, 2002 (the "Current Quarter").

2. HEDGING ACTIVITIES AND FINANCIAL INSTRUMENTS

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of this exposure to adverse market changes, we have entered into derivative instruments. As of March 31, 2002, our derivative instruments were comprised of swaps, collars, cap-swaps, straddles, strangles and basis protection swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price.

If the market price is between the call and the put strike price, then no payments are due from either party.

- For cap-swaps, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure.

- For straddles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option which establish a fixed price. To the extent that the market price differs from the established fixed price, Chesapeake pays the counterparty.

- For strangles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option. If the market price exceeds the fixed price of the call option or falls below the fixed price of the put option, then Chesapeake pays the counterparty. If the market price settles between the fixed price of the call and put option, no payment is due from Chesapeake.

- Basis protection swaps are arrangements that guarantee a price differential of oil and gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

From time to time, we close certain swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectiveness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

The estimated fair values of our oil and gas derivative instruments as of March 31, 2002 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	MARCH 31, 2002

	($ IN THOUSANDS)
Derivative assets (liabilities):	
Fixed-price gas swaps....................	$ (18,504)
Fixed-price gas collars..................	7,046
Fixed-price gas cap-swaps................	25,949
Gas basis protection swaps...............	(6,222)
Gas straddles............................	(25,825)
Gas strangles............................	(31,004)
Fixed-price gas counter-swaps............	2,239
Fixed-price gas locked swaps.............	43,716
Fixed-price crude oil cap-swaps..........	(2,286)
Fixed-price crude oil locked swaps.......	1,404
Total....................................	$ (3,487)(a)

(a) After adjusting for the $40.9 million premium paid to Chesapeake by the counterparty at the inception of the straddle and strangle contracts (which is recorded in cash provided by operating activities on the accompanying consolidated statements of cash flows), the net value of the combined hedging portfolio at March 31, 2002 was $37.4 million.

We expect to transfer approximately $12.9 million of the balance in accumulated other comprehensive income, based upon the market prices at March 31, 2002, to earnings during the next 12 months when the forecasted transactions actually occur. All forecasted transactions hedged as of March 31, 2002 are expected to mature by December 2005.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows ($ in thousands):

Fair value of contracts outstanding at January 1, 2002	$ 157
Change in fair value of contracts during period	(69
Contracts realized or otherwise settled during the period	(48
Fair value of new contracts when entered into during the period	(42
Changes in fair values attributable to changes in valuation techniques and assumptions	
Fair value of contracts outstanding at March 31, 2002	$ (3

Risk management loss related to our oil and gas derivatives for the three months ended March 31, 2002 is comprised of the following ($ in thousands):

Risk Management Loss:	
Change in fair value of derivatives not qualifying for hedge accounting	$(53,414)
Reclassification of settled contracts	(25,077)
Ineffective portion of derivatives qualifying for hedge accounting ...	(824)
Total	$(79,315)

Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

Interest Rate Risk

We also utilize hedging strategies to manage interest rate exposure. In March 2002, we entered into an interest rate swap to convert a portion of our fixed rate debt to floating rate debt. The terms of the swap agreement are as follows:

MONTHS	NOTIONAL AMOUNT	FIXED RATE	FLOATING RATE
March 2002 - March 2004	$200,000,000	7.875%	U.S. six-mont arrears plus points

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. Payments under the interest rate swap coincide with the semi-annual interest payments on our 7.875% senior notes which are due September 15 and March 15 of each year beginning September 15, 2002.

A portion of the interest rate swap was entered into to convert $129 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of the interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge. Accordingly, the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to the debt's carrying value.

The remaining $71 million of the interest rate swap has not been designated as a fair value hedge. The mark-to-market value of this portion of the instrument is recorded as a derivative asset or liability on the consolidated balance sheets with the offsetting amount reflected in risk management income (loss) on the consolidated statements of operations. The amount recorded in risk management income (loss) will be reversed and reflected in interest expense when the swap is settled.

The estimated fair value of the interest rate swap at March 31, 2002 was a liability of approximately $0.4 million comprised of $0.2 million reflected as risk management loss and $0.2 million reflected as a reduction to long-term debt. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the swap agreement.

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, Disclosures About Fair Value of

Financial Instruments. We have determined the estimated fair value amounts by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term (including current maturities), fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt at March 31, 2002 and December 31, 2001 was $1,308.8 million and $1,330.1 million, respectively, compared to approximate fair values of $1,322.2 million and $1,343.0 million, respectively. The carrying value of other long-term debt approximates its fair value as interest rates are primarily variable, based on prevailing market rates. The carrying amount for our 6.75% convertible preferred stock at March 31, 2002 was $150.0 million, which approximated its fair value as of that date.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and cash equivalents, including restricted cash, and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas and interest rate volatility. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. The industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively,

in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

3. CONTINGENCIES AND COMMITMENTS

West Panhandle Field Cessation Cases. One of our subsidiaries, Chesapeake Panhandle Limited Partnership ("CP") (f/k/a MC Panhandle, Inc.), and two subsidiaries of Kinder Morgan, Inc. have been defendants in 16 lawsuits filed between June 1997 and December 2001 by royalty owners seeking the cancellation of oil and gas leases in the West Panhandle Field in Texas. MC Panhandle, Inc., which we acquired in April 1998, has owned the leases since January 1, 1997. The co-defendants are prior lessees. The plaintiffs in these cases have claimed the leases terminated upon the cessation of production for various periods, primarily during the 1960s. In addition, the plaintiffs have sought to recover conversion damages, exemplary damages, attorneys' fees and interest. The defendants have asserted that any cessation of production was excused and have pled affirmative defenses of limitations, waiver, temporary estoppel, laches and title by adverse possession. Four of the 16 cases have been tried, and there have been appellate decisions in three of them.

In January 2001, we settled the claims of the principal plaintiffs in eight cases tried or pending in the District Court of Moore County, Texas, 69th Judicial District. The settlement was not material to our financial condition or results of operations. In December 2001, the Texas Supreme Court accepted for review petitions we filed with respect to the claims of plaintiffs in two of these cases who were not covered by the settlement. The Court heard oral arguments in March 2002.

There are eight other related West Panhandle cessation cases which continue to be pending, three in the District Court of Moore County, Texas, 69th Judicial District, two in the District Court of Carson County, Texas, 100th Judicial District, and three in the U.S. District Court, Northern District of Texas, Amarillo Division. In one of the Moore County cases, CP and the other defendants have appealed a January 2000 judgment notwithstanding verdict in favor of plaintiffs. In addition to quieting title to the lease (including existing gas wells and all attached equipment) in plaintiffs, the court awarded actual damages against CP in the amount of $716,400 and exemplary damages in the amount of $25,000. The court further awarded, jointly and severally from all defendants, $160,000 in attorneys' fees and interest and court costs. On March 28, 2001, the Amarillo Court of Appeals reversed and rendered judgment in favor of CP and the other defendants, finding that the subject leases had been revived as a matter of law, making all other issues moot. Plaintiffs have filed petitions requesting that the Texas Supreme Court accept the case for review. In another of the Moore County, Texas cases, in June 1999, the court granted plaintiffs' motion for summary judgment in part, finding that the lease had terminated due to the cessation of production, subject to the defendants' affirmative defenses. In February 2001, the court granted plaintiffs' motion for summary judgment on defendants' affirmative defenses but reversed its ruling that the lease had terminated as a matter of law. In one of the U.S. District Court cases, after a trial in May 1999, the jury found plaintiffs' claims were barred by the payment of shut-in royalties, laches and revivor. Plaintiffs have moved for a new trial. There are motions pending in two other cases, and the remaining three cases are in the pleading stage.

We have previously established an accrued liability we believe will be sufficient to cover the estimated costs of litigation for each of the pending cases. Because of the inconsistent verdicts reached by the juries in the four cases tried to date and because the amount of damages sought is not specified in all of the pending cases, the outcome of any future trials and the amount of damages that might ultimately be awarded could differ from management's estimates. CP and the other defendants are vigorously defending against the plaintiffs' claims.

Chesapeake is currently involved in various other routine disputes incidental to its business operations. Management, after consultation with legal counsel, is of the opinion that the final resolution of all such currently pending or threatened litigation is not likely to have a material adverse effect on the consolidated financial position or results of operations of Chesapeake.

Due to the nature of the oil and gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake is not aware of any potential material environmental issues or claims.

4. NET INCOME PER SHARE

Statement of Financial Accounting Standards No. 128, Earnings Per Share, requires presentation of "basic" and "diluted" earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

- For the quarter ended March 31, 2002, outstanding warrants to purchase 1.1 million shares of common stock at a weighted average exercise price of $12.61 were antidilutive because the exercise prices of the warrants were greater than the average price of the common stock during the Current Quarter.

- For the quarter ended March 31, 2002 and 2001, outstanding options to purchase 0.8 million and 0.1 million shares of common stock at a weighted average exercise price of $10.05 and $25.00, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.

- As a result of the Current Quarter's net loss to common shareholders, the diluted shares do not include the effect of outstanding stock options to purchase 5.2 million shares of common stock at a weighted average exercise price of $3.81, the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares) or warrants to purchase 6,567 shares of common stock at a weighted average exercise price of $0.05 as the effects were antidilutive.

A reconciliation for the quarter ended March 31, 2001 is as follows:

	INCOME (NUMERATOR)	SHARES (DENOMINA
	(IN THOUSANDS, EXCEPT	
FOR THE QUARTER ENDED MARCH 31, 2001:		
BASIC EPS		
Income available to common shareholders	$ 69,742	157,
EFFECT OF DILUTIVE SECURITIES		
Assumed conversion at the beginning of the period of preferred shares exchanged during the period:		
Preferred stock dividends	546	
Assumed conversion of 624,037 shares of 7% preferred stock at beginning of period	--	4,
Employee stock options	--	8,
DILUTED EPS		
Income available to common shareholders and assumed conversions	$ 70,288	170,

On November 13, 2001, we issued 3.0 million shares of 6.75% cumulative convertible preferred stock, par value $0.01 per share and liquidation preference $50 per share, in a private offering. We subsequently registered under the Securities Act of 1933 shares of the preferred stock and underlying common stock for resale by the holders.

5. SENIOR NOTES AND REVOLVING CREDIT FACILITY

On November 5, 2001, Chesapeake closed a private offering of $250.0 million of 8.375% senior notes due 2008, all of which were exchanged on January 23, 2002 for substantially identical notes registered under the Securities Act of 1933. The 8.375% senior notes will be redeemable by us prior to November 1, 2005 at the make-whole prices determined in accordance with the indenture, and on and after November 1, 2005 at annually declining redemption prices.

On April 6, 2001, we issued $800.0 million principal amount of 8.125% senior notes due 2011, all of which were subsequently exchanged for substantially identical notes registered under the Securities Act of 1933. The 8.125% senior notes will be redeemable by us prior to April 1, 2006 at the make-whole prices determined in accordance with the indenture, and on and after April 1, 2006 at annually declining redemption prices.

On March 17, 1997, we issued $150.0 million principal amount of 7.875% senior notes due 2004. The 7.875% senior notes are redeemable at our option at any time prior to March 15, 2004 at the make-whole prices determined in accordance with the indenture. During the Current Quarter, we purchased and subsequently retired $21.0 million of these notes for total consideration of $21.9 million, including $0.5 million of accrued interest and $0.4 million of redemption premium.

Also on March 17, 1997, we issued $150.0 million principal amount of 8.5% senior notes due 2012. The 8.5% senior notes are redeemable at our option at any time prior to March 15, 2004 at the make-whole prices determined in accordance with the indenture and, on or after March 15, 2004, at annually declining redemption prices set forth in the indenture. During the quarter ended March 31, 2001, Chesapeake purchased and subsequently retired $7.3 million of these notes for total consideration of $7.4 million, including accrued interest of $0.2 million and the write-off of $0.1 million of unamortized bond discount.

The senior note indentures contain covenants limiting us and the guarantor subsidiaries with respect to asset sales; restricted payments; the incurrence of additional indebtedness and the issuance of preferred stock; liens; sale and leaseback transactions; lines of business; dividend and other payment restrictions affecting guarantor subsidiaries; mergers or consolidations; and transactions with affiliates. The senior note indentures also limit our ability to make restricted payments (as defined), including the payment of cash dividends, unless the debt incurrence and other tests are met.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under the 8.375% senior notes, the 8.125% senior notes, the 7.875% senior notes and the 8.5% senior notes have been fully and unconditionally guaranteed, on a joint and several basis, by each of our "restricted subsidiaries" (as defined in the respective indentures governing these notes) (collectively, the "guarantor subsidiaries"). Each guarantor subsidiary is a direct or indirect wholly-owned subsidiary.

We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of March 31, 2002, we had no outstanding borrowings under this facility and were using $21.3 million of the facility to secure various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically. The maturity of the bank credit facility can be extended to June 2005 provided certain conditions are met.

The credit facility agreement contains various covenants and restrictive provisions including incurring additional indebtedness, selling properties, paying dividends, purchasing or redeeming our capital stock, making investments or loans, purchasing certain of our senior notes, creating liens, and making acquisitions. The credit facility agreement requires us to maintain a current ratio of at least 1 to 1 and a fixed charge coverage ratio of at least 2.5 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $5.0 million.

Set forth below are condensed consolidating financial statements of the guarantor subsidiaries and our subsidiaries which are not guarantors of the senior notes. Chesapeake Energy Marketing, Inc. was a non-guarantor subsidiary for all periods presented. All of our other wholly-owned subsidiaries were guarantor subsidiaries during all periods presented.

CONDENSED CONSOLIDATED BALANCE SHEET
AS OF DECEMBER 31, 2001
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARY	NON-GUARANTOR SUBSIDIARY	PARENT
ASSETS			
CURRENT ASSETS:			
Cash and cash equivalents	$ (7,905)	$ 19,714	$ 113,151
Accounts receivable	113,493	30,380	2,715
Short-term derivative instruments	97,544	--	--
Inventory and other	10,208	421	--
Total Current Assets	213,340	50,515	115,866
PROPERTY AND EQUIPMENT:			
Oil and gas properties	3,546,163	--	--
Unevaluated leasehold	66,205	--	--
Other property and equipment	53,681	23,537	38,476
Less: accumulated depreciation, depletion and amortization	(1,920,613)	(18,668)	(3,200)
Net Property and Equipment	1,745,436	4,869	35,276

OTHER ASSETS:			
Investments in subsidiaries and intercompany advances	--	--	(21,054)
Long-term derivative receivable	18,852	--	--
Deferred income tax asset	(218,596)	(1,376)	287,753
Long-term derivative instruments	6,370	--	--
Long-term investments	--	--	29,849
Other assets	5,589	334	11,050
Total Other Assets	(187,785)	(1,042)	307,598
TOTAL ASSETS	$ 1,770,991	$ 54,342	$ 458,740
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)			
CURRENT LIABILITIES:			
Notes payable and current maturities of long-term debt	$ 602	$ --	$ --
Accounts payable and other current liabilities	127,967	36,755	26,338
Total Current Liabilities	128,569	36,755	26,338
LONG-TERM DEBT	--	--	1,329,453
REVENUES AND ROYALTIES DUE OTHERS	12,696	--	--
OTHER LIABILITIES	3,831	--	--
INTERCOMPANY PAYABLES	1,664,517	19	(1,664,458)
STOCKHOLDERS' EQUITY (DEFICIT):			
Common Stock	66	1	1,686
Other	(38,688)	17,567	765,721
Total Stockholders' Equity (Deficit)	(38,622)	17,568	767,407
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,770,991	$ 54,342	$ 458,740

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CONDENSED CONSOLIDATED BALANCE SHEET
AS OF MARCH 31, 2002
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT
ASSETS			
CURRENT ASSETS:			

Cash and cash equivalents	$ (28,789)	$ 10,136	$ 140,860
Accounts receivable	118,455	40,917	4,384
Inventory and other	10,080	366	15
Total Current Assets	99,746	51,419	145,259
PROPERTY AND EQUIPMENT:			
Oil and gas properties	3,636,641	--	--
Unevaluated leasehold	60,007	--	--
Other property and equipment	55,633	23,810	43,779
Less: accumulated depreciation, depletion and amortization	(1,970,575)	(18,897)	(3,456)
Net Property and Equipment	1,781,706	4,913	40,323
OTHER ASSETS:			
Investments in subsidiaries and intercompany advances	--	--	85,892
Long-term derivative receivable	12,220	--	--
Deferred income tax asset	(26,226)	(1,455)	131,556
Long-term investments	--	--	28,546
Other assets	4,790	251	10,583
Total Other Assets	(9,216)	(1,204)	256,577
TOTAL ASSETS	$ 1,872,236	$ 55,128	$ 442,159

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

CURRENT LIABILITIES:			
Notes payable and current maturities of long-term debt	$ 380	$ --	$ --
Accounts payable and other current liabilities	122,717	38,916	41,547
Total Current Liabilities	123,097	38,916	41,547
LONG-TERM DEBT	--	--	1,308,424
REVENUES AND ROYALTIES DUE OTHERS	12,643	--	--
LONG-TERM DERIVATIVE INSTRUMENTS	38,660	--	431
OTHER LIABILITIES	3,831	--	--
INTERCOMPANY PAYABLES	1,627,707	(3,382)	(1,624,331)
STOCKHOLDERS' EQUITY (DEFICIT):			
Common Stock	66	1	1,696
Other	66,232	19,593	714,392
Total Stockholders' Equity (Deficit)	66,298	19,594	716,088
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)	$ 1,872,236	$ 55,128	$ 442,159

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARE
FOR THE THREE MONTHS ENDED MARCH 31, 2001:			
REVENUES:			
Oil and gas sales	$ 221,219	$ --	$
Oil and gas marketing sales	--	133,913	
Total Revenues	221,219	133,913	
OPERATING COSTS:			
Production expenses and taxes	32,083	--	
General and administrative	3,543	350	
Oil and gas marketing expenses	--	132,226	
Oil and gas depreciation, depletion and amortization ...	38,173	--	
Other depreciation and amortization	1,062	20	
Total Operating Costs	74,861	132,596	
INCOME (LOSS) FROM OPERATIONS	146,358	1,317	(
OTHER INCOME (EXPENSE):			
Interest and other income	442	75	22,
Interest expense	(27,814)	(1)	(20,
Gothic standby credit facility costs	--	--	(3,
Equity in net earnings of subsidiaries	--	--	71,
Total Other Income (Expense)	(27,372)	74	70,
INCOME (LOSS) BEFORE INCOME TAXES	118,986	1,391	69,
INCOME TAX EXPENSE (BENEFIT)	48,097	556	(
NET INCOME (LOSS)	$ 70,889	$ 835	$ 70,

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARE
FOR THE THREE MONTHS ENDED MARCH 31, 2002:			
REVENUES:			
Oil and gas sales	$ 141,971	$ --	$
Risk management loss	(79,315)	--	(
Oil and gas marketing sales	--	89,465	

Total Revenues	62,656	89,465	(
OPERATING COSTS:			
Production expenses and taxes	27,276	--	
General and administrative	3,630	451	
Oil and gas marketing expenses	--	88,639	
Oil and gas depreciation, depletion and amortization	48,619	--	
Other depreciation and amortization	2,171	277	
Total Operating Costs	81,696	89,367	
INCOME (LOSS) FROM OPERATIONS	(19,040)	98	(1,
OTHER INCOME (EXPENSE):			
Interest and other income	209	99	28,
Interest expense	(26,569)	--	(27,
Equity in net earnings of subsidiaries	--	--	(27,
Total Other Income (Expense).	(26,360)	99	(26,
INCOME (LOSS) BEFORE INCOME TAXES	(45,400)	197	(27,
INCOME TAX EXPENSE (BENEFIT)	(18,160)	79	(
NET INCOME (LOSS)	$ (27,240)	$ 118	$(27,

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT
FOR THE THREE MONTHS ENDED MARCH 31, 2001:			
CASH FLOWS FROM OPERATING ACTIVITIES	$ 200,370	$ (1,721)	$ 79,424
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties, net	(153,699)	--	--
Proceeds from sale of assets	35	--	--
Additions to other property and equipment	(8,745)	(890)	(3,425)
Other	269	--	--
Cash (used in) provided by investing activities	(162,140)	(890)	(3,425)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from long-term borrowings	--	--	93,000
Payments on long-term borrowings	--	--	(103,500)
Cash paid for financing cost related to debt	(99)	--	(613)
Cash dividends paid on preferred stock	--	--	(546)
Cash paid for repurchase on senior notes	(1,020)	--	(7,235)
Exercise of stock options	--	--	2,191

Intercompany advances, net	(46,514)	(4,066)	(21,144)
Cash (used in) provided by financing activities	(47,633)	(4,066)	(37,847)
Effect of exchange rate changes on cash	(869)	--	--
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(10,272)	(6,677)	38,152
CASH, BEGINNING OF PERIOD	(19,868)	7,200	12,668
CASH, END OF PERIOD	$ (30,140)	$ 523	$ 50,820

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT
FOR THE THREE MONTHS ENDED MARCH 31, 2002:			
CASH FLOWS FROM OPERATING ACTIVITIES	$ 107,118	$ (7,847)	$ (9,096)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Oil and gas properties, net	(84,175)	--	--
Proceeds from sale of assets	31	--	--
Additions to other property, plant and equipment and other	(2,051)	(268)	(5,303)
Other investments, net	--	--	1,807
Cash (used in) provided by investing activities	(86,195)	(268)	(3,496)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Cash paid for financing costs related to debt	--	--	(84)
Cash paid for repurchase of senior notes	--	--	(21,000)
Cash paid for repurchase premium on senior notes	--	--	(440)
Cash dividends paid on preferred stock	--	--	(2,587)
Exercise of stock options	--	--	1,181
Other	--	--	(50)
Intercompany advances, net	(38,654)	(1,463)	67,239
Cash (used in) provided by financing activities	(38,654)	(1,463)	44,259
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(17,731)	(9,578)	31,667
CASH, BEGINNING OF PERIOD	(11,313)	19,714	109,193
CASH, END OF PERIOD	$ (29,044)	$ 10,136	$140,860

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

($ IN THOUSANDS)

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT
FOR THE THREE MONTHS ENDED MARCH 31, 2001:			
Net income (loss)	$ 70,889	$ 835	$ 70,28
Other comprehensive income (loss) net of income tax -			
Foreign currency translation adjustments	(3,219)	--	-
Cumulative effect of accounting change for financial derivatives, net of income tax	(53,580)	--	-
Change in fair value of derivative instruments	42,138	--	-
Reclassification of settled contracts	18,326	--	-
Equity in net other comprehensive income (loss) of subsidiaries	--	--	3,66
Comprehensive income (loss)	$ 74,554	$ 835	$ 73,95

	GUARANTOR SUBSIDIARIES	NON-GUARANTOR SUBSIDIARY	PARENT
FOR THE THREE MONTHS ENDED MARCH 31, 2002:			
Net income (loss)	$ (27,240)	$ 118	$(27,58
Other comprehensive income (loss) net of income tax -			
Change in fair value of derivative instruments	(10,730)	--	-
Reclassification of settled contracts	(14,086)	--	-
Ineffectiveness portion of derivatives qualifying for hedge accounting	494	--	-
Equity in net other comprehensive income (loss) of subsidiaries	--	--	(24,32
Comprehensive income (loss)	$ (51,562)	$ 118	$(51,90

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6. SEGMENT INFORMATION

Chesapeake has two reportable segments under SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, consisting of exploration and production, and marketing. The reportable segment information can be derived from note 5 as Chesapeake Energy Marketing, Inc., which is our marketing segment, is the only non-guarantor subsidiary for all income statement periods presented.

7. SUBSEQUENT EVENT

On April 19, 2002, we entered into an agreement and plan of merger pursuant to which we will acquire Canaan Energy Corporation in a cash merger through a Chesapeake subsidiary. Under the agreement, all outstanding common shares of Canaan, other than the Canaan shares owned by Chesapeake and those that dissent, will be converted into the right to receive $18.00 per share in cash, and outstanding options to acquire Canaan common stock will be converted into the right to receive, for each share of Canaan common stock to be received upon exercise, the merger consideration less the per share exercise price and withholding taxes. We expect the aggregate net cash consideration for the merger will be $118 million, including the retirement of Canaan's outstanding indebtedness of approximately $33 million (net of stock option proceeds and working capital). The acquisition is subject to approval by Canaan's shareholders. Canaan's management and directors have agreed to vote their 1.2 million common shares in favor of the agreement. These shares, together with the Canaan shares we own, represent 37% of Canaan's outstanding common shares. The merger is expected to close in the third quarter of 2002. Under certain circumstances, Canaan has agreed to provide Chesapeake with a $5.0 million break-up fee in the event the transaction is not completed. We intend to pay for the transaction with cash on hand.

8. RECENT ACCOUNTING PRONOUNCEMENTS

In June 2001, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards Nos. 141 and 142. SFAS No. 141, Business Combinations, requires that the purchase method of accounting be used for all business combinations initiated after June 30, 2001. SFAS No. 142, Goodwill and Other Intangible Assets, changes the accounting for goodwill from an amortization method to an impairment-only approach and was effective January 2002. We have adopted these new standards, which have not had a significant effect on our results of operations or our financial position.

In June 2001, the FASB issued SFAS No. 143, Accounting for Asset Retirement Obligations. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. We have not yet determined the effect of the adoption of SFAS No. 143 on our financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. SFAS 144 was effective January 1, 2002. This statement supersedes SFAS No. 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of, and amends Accounting Principles Board Opinion No. 30 for the accounting and reporting of discontinued operations, as it relates to long-lived assets. Adoption of SFAS 144 did not affect our financial position or results of operations.

PART I. FINANCIAL INFORMATION

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

OVERVIEW

The following table sets forth certain information regarding the production volumes, oil and gas sales, average sales prices received and expenses for the periods indicated:

	QUARTER ENDED MARCH 3	
	2001	2002
NET PRODUCTION:		
Oil (mbbl)	686	
Gas (mmcf)	36,040	36,
Gas equivalent (mmcfe)	40,156	41,
OIL AND GAS SALES ($ IN THOUSANDS):		
Oil	$ 19,904	$ 19,
Gas	201,315	122,
Total oil and gas sales	$ 221,219	$ 141,
AVERAGE SALES PRICE:		
Oil ($ per bbl)	$ 29.01	$ 24
Gas ($ per mcf)	$ 5.59	$ 3
Gas equivalent ($ per mcfe)	$ 5.51	$ 3
EXPENSES ($ PER MCFE):		
Production expenses and taxes	$ 0.80	$ 0
General and administrative	$ 0.10	$ 0
Depreciation, depletion and amortization	$ 0.95	$ 1
NET WELLS DRILLED	81	
NET WELLS AT END OF PERIOD	3,338	3,

RESULTS OF OPERATIONS -- THREE MONTHS ENDED MARCH 31, 2002 ("CURRENT QUARTER") VS. MARCH 31, 2001 ("PRIOR QUARTER")

General. For the Current Quarter, Chesapeake had a net loss available to common shareholders of $30.1 million, or a loss of $0.18 per diluted common share, on total revenues of $89.8 million. This compares to net income available to common shareholders of $69.7 million, or $0.41 per diluted common share, on total revenues of $277.4 million during the Prior Quarter. The Current Quarter's net loss included, on a pre-tax basis, a non-cash $79.5 million risk management loss.

Oil and Gas Sales. During the Current Quarter, oil and gas sales decreased 36% to $142.0 million from $221.2 million in the Prior Quarter. For the Current Quarter, we produced 41.9 billion cubic feet equivalent, consisting of 0.8 million barrels of oil and 36.9 billion cubic feet of gas, compared to 0.7 mmbbl and 36.0 bcf, or 40.2 bcfe, in the Prior Quarter. The production increase is primarily the result of various acquisitions which occurred in late 2001 and successful drilling results, partially offset by the sale of our Canadian reserves effective October 1, 2001. Average oil prices realized were $24.05 per bbl in the Current Quarter compared to $29.01 per bbl in the Prior Quarter, a decrease of 17%. Average gas prices realized were $3.30 per thousand cubic feet in the Current Quarter compared to $5.59 per mcf in the Prior Quarter, a decrease of 41%.

The following table shows our production by region for the Prior Quarter and the Current Quarter:

FOR THE THREE MONTHS ENDED MARCH 31,

OPERATING AREAS	2001 (MMCFE)	2001 PERCENT	2002 (MMCFE)	2002 PERCENT
Mid-Continent	26,888	67%	31,793	76%
Gulf Coast	8,268	21	7,261	17
Canada	2,688	7	--	--
Permian Basin	1,559	4	2,064	5
Other areas	753	1	795	2
Total	40,156	100%	41,913	100%

Gas production represented approximately 88% of our total production volume on an equivalent basis in the Current Quarter, compared to 90% in the Prior Quarter.

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For the Current Quarter, we realized an average price of $3.39 per mcfe, compared to $5.51 per mcfe in the Prior Quarter, including in each case the effects of hedging. Our hedging activities resulted in increased oil and gas revenues of $48.6 million, or $1.16 per mcfe, in the Current Quarter, compared to decreases in oil and gas revenues of $30.5 million, or $0.76 per mcfe, in the Prior Quarter.

Risk Management Loss. Chesapeake recognized a $79.5 million risk management loss in the Current Quarter, compared to no such income (loss) in the Prior Quarter. Risk management loss for the Current Quarter consisted of a $53.4 million loss related to changes in fair value of derivatives not designated as cash flow hedges, $25.1 million of reclassifications related to the settlement of such contracts, a $0.8 million loss associated with the ineffective portion of derivatives qualifying for hedge accounting and a $0.2 million loss associated with the portion of our interest rate swap that does not qualify for fair value hedge accounting.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. There is also a portion of our interest rate swap that does not qualify as a fair value hedge. Therefore, changes in fair value of these instruments that occur prior to their maturity, together with any change in fair value of hedges resulting from ineffectiveness, are reported in the statement of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and are included in oil and gas sales and interest expense, as applicable, over the respective contract terms. Detailed information about our oil and gas hedging positions appears in Item 3 - Quantitative and Qualitative Disclosures About Market Risk.

Oil and Gas Marketing Sales. We generated $27.3 million in oil and gas marketing sales for third parties in the Current Quarter, with corresponding oil and gas marketing expenses of $26.5 million, for a net margin of $0.8 million. This compares to sales of $56.2 million, expenses of $54.5 million, and a net margin of $1.7 million in the Prior Quarter. The decrease in marketing sales and cost of sales was due primarily to a decrease in oil and gas prices in the

Current Quarter compared to the Prior Quarter, partially offset by a 25% increase in volumes marketed by Chesapeake Energy Marketing, Inc. in the Current Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, increased to $22.1 million in the Current Quarter, a $4.3 million increase from the $17.8 million of production expenses incurred in the Prior Quarter. On a unit of production basis, production expenses were $0.53 and $0.44 per mcfe in the Current and Prior Quarters, respectively. The increase in costs on a per unit basis in the Current Quarter is due primarily to increased field service costs, higher production costs associated with properties acquired in 2001 and an increase in ad valorem taxes. We expect that lease operating expenses per mcfe for the remainder of 2002 will range from $0.50 to $0.55.

Production Taxes. Production taxes were $5.2 million and $14.3 million in the Current and Prior Quarters, respectively. On a per unit basis, production taxes were $0.12 per mcfe in the Current Quarter compared to $0.36 per mcfe in the Prior Quarter. The decrease in the Current Quarter was the result of decreased prices and new statutory exemptions on certain wells in Oklahoma and Texas. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and gas prices are higher. We expect production taxes for the remainder of 2002 to be approximately 7% of oil and gas sales revenues after excluding any impact from hedging.

General and Administrative. General and administrative expenses, which are net of capitalized internal costs, were $4.3 million in the Current Quarter compared to $4.0 million in the Prior Quarter.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $2.5 million and $1.8 million of internal costs in the Current Quarter and Prior Quarter, respectively, directly related to our oil and gas exploration and development efforts. We anticipate that general and administrative expenses for the remainder of 2002 will be between $0.10 and $0.11 per mcfe, which is approximately the same level as 2001 and the Current Quarter.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Quarter was $48.6 million, compared to $38.2 million in the Prior Quarter. The DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves

in the periods presented, increased from $0.95 in the Prior Quarter to $1.16 per mcfe in the Current Quarter. We expect the DD&A rate for the remainder of 2002 to be between $1.15 and $1.25 per mcfe.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $3.1 million in the Current Quarter, compared to $2.0 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation recorded on recently acquired fixed assets. Other property and equipment costs are depreciated on both straight-line and accelerated methods. Buildings are depreciated on a straight-line basis over 31.5 years. Drilling rigs are depreciated on a straight-line basis over 12 years. All other property and equipment are depreciated over the estimated useful lives of the assets, which range from five to seven years. We expect depreciation and amortization of other assets to average between $0.06 and $0.08 per mcfe for the remainder of 2002.

Interest and Other Income. Interest and other income for the Current Quarter was $1.0 million compared to $0.6 million in the Prior Quarter. The increase was primarily the result of additional interest income from significant cash balances held during the Current Quarter. Also, the recognition of a $0.5 million gain on the sale of RAM Energy, Inc. notes was offset by a $0.6 million loss on the repurchase of our 7.875% senior notes.

Interest Expense. Interest expense increased to $27.0 million in the Current Quarter from $25.9 million in the Prior Quarter. The increase in the Current Quarter is due to a $166.6 million increase in average long-term borrowings in the Current Quarter compared to the Prior Quarter, partially offset by a decrease in the overall average interest rate. In addition to the interest expense reported, we capitalized $1.1 million of interest during the Current Quarter, compared to $0.9 million capitalized in the Prior Quarter, on significant investments in unproved properties that were not being currently depreciated, depleted or amortized and on which exploration activities were in progress. Interest is capitalized using the weighted average interest rate of our outstanding borrowings. We anticipate that capitalized interest for the remainder of 2002 will be between $3.0 million and $4.0 million.

Gothic Standby Credit Facility Costs. During the Prior Quarter, we obtained a standby commitment for a $275 million credit facility, consisting of a $175 million term loan and a $100 million revolving credit facility which, if needed, would have replaced our then existing revolving credit facility. The term loan was available to provide funds to repurchase any of Gothic Production Corporation's 11.125% senior secured notes tendered following the closing of the Gothic acquisition in January 2001 pursuant to a change-of-control offer to purchase. In February 2001, we purchased $1.0 million of notes tendered for 101% of such amount. We did not use the standby credit facility and the commitment terminated in February 2001. Chesapeake incurred $3.4 million of costs for the standby facility, which were recognized in the Prior Quarter.

Provision (Benefit) for Income Taxes. Chesapeake recorded an income tax benefit of $18.4 million in the Current Quarter, compared to income tax expense of $47.7 million in the Prior Quarter. Income tax expense for the Prior Quarter was comprised of $43.2 million related to our domestic operations and $4.5 million related to our Canadian operations which were sold on October 1, 2001. We anticipate that all 2002 income tax expense will be deferred.

CASH FLOWS FROM OPERATING, INVESTING, AND FINANCING ACTIVITIES

Cash Flows from Operating Activities. Cash provided by operating activities decreased 43% to $117.3 million during the Current Quarter compared to $206.3 million during the Prior Quarter. The decrease was due primarily to lower oil and gas prices realized during the Current Quarter.

Cash Flows from Investing Activities. Cash used in investing activities decreased to $90.0 million during the Current Quarter from $166.5 million in the Prior Quarter. During the Current Quarter we expended approximately $75.9 million to initiate drilling on 119 (57.4 net) wells and invested approximately $7.4 million in leasehold acquisitions. This compares to $95.5 million to initiate drilling on 163 (80.8 net) wells and $14.4 million to purchase leasehold in the Prior Quarter. During the Current Quarter, we had acquisitions of oil and gas properties of $0.9 million and no divestitures of oil and gas properties. This compares to cash used in acquisitions of oil and gas companies and properties of $44.0 million and divestitures of $0.1 million in the Prior Quarter. During the Current Quarter, we had additional investments in other assets of $7.4 million compared to $13.1 million in the Prior Quarter. The Current Quarter included additional investments in the common stock of two oil and gas companies totaling $2.4 million and $4.2 million in proceeds related to the sale of RAM Energy, Inc. notes.

Cash Flows from Financing Activities. There was $23.0 million of cash used in financing activities in the Current Quarter, compared to $17.8 million in the Prior Quarter. The activity in the Current Quarter reflects the repurchase of $21.0 million of our 7.875% senior notes, $1.2 million in cash received from the exercise of stock

options, and $2.6 million used to pay dividends on the 6.75% preferred stock. The activity in the Prior Quarter includes $10.5 million in net reductions in long-term borrowings, $8.3 million used to repurchase long-term debt, and $2.2 million in cash received from the exercise of stock options.

LIQUIDITY AND CAPITAL RESOURCES

Sources of Liquidity

Chesapeake had working capital of $92.9 million at March 31, 2002, including $122.0 million in cash. Additionally, we have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of March 31, 2002 we had no outstanding borrowings under the facility and were using $21.3 million of the facility to secure various letters of credit. We believe we will have adequate resources, including operating cash flows, working capital and proceeds from our revolving bank credit facility, to fund our capital expenditure budget for exploration and development activities during the remainder of 2002, which is currently estimated to be approximately $330 million before the pending Canaan acquisition, and $450 million pro forma for the Canaan acquisition. Further, our drilling program is largely discretionary and can be adjusted to match changing circumstances. Based on our current cash flow assumptions and giving effect to the Canaan acquisition, we expect operating cash flow to reach $400 million during 2002. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayments or other general corporate purposes in 2002.

A significant portion of our liquidity is concentrated in cash and cash equivalents, including restricted cash, and derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments and accounts receivables. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. The industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. Cash and cash equivalents are deposited with major banks or institutions with high credit ratings.

Our liquidity is not dependent on the use of off-balance sheet financing arrangements, such as the securitization of receivables or obtaining access to assets through special purpose entities. We have not relied on off-balance sheet financing arrangements in the past and we do not intend to rely on such arrangements in the future as a source of liquidity. We are not a commercial paper issuer.

Contractual Obligations and Commercial Commitments

We have a $225 million revolving bank credit facility (with a committed borrowing base of $225 million) which matures in September 2003. As of March 31, 2002, we had no outstanding borrowings under this facility and were using $21.3 million of the facility to secure various letters of credit. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either the reference rate of Union Bank of California, N.A., or London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to total facility usage. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee of 0.50%. Interest is payable quarterly.

The credit facility agreement contains various covenants and restrictive provisions including incurring additional indebtedness, selling properties, paying dividends, purchasing or redeeming our capital stock, making investments or loans or purchasing certain of our senior notes, creating liens, and making acquisitions. The credit facility agreement requires us to maintain a current ratio of at least 1 to 1 and a fixed charge coverage ratio of at least 2.5 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $5.0 million.

As of March 31, 2002, senior notes represented $1.3 billion of our long-term debt and consisted of the following: $800.0 million principal amount of 8.125% senior notes due 2011, $250.0 million principal amount of 8.375% senior notes due 2008, $129.0 million principal amount of 7.875% senior notes due 2004 and $142.7 million

principal amount of 8.5% senior notes due 2012. There are no scheduled principal payments required on any of the senior notes until March 2004, when $128.0 million is due, giving effect to the repurchase and retirement of $21.0 million of our 7.875% senior notes in the Current Quarter and an additional $1.0 million in April 2002. Debt ratings for the senior notes are B1 by Moody's Investor Service, B+ by Standard & Poor's Ratings Services and BB- by Fitch Ratings as of March 31, 2002. Debt ratings for our secured bank credit facility are Ba3 by Moody's Investor Service, BB by Standard & Poor's Ratings Services and BB+ by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly owned subsidiaries except Chesapeake Energy Marketing, Inc. guarantee the notes. The 7.875% senior notes are redeemable at our option at any time prior to March 15, 2004 at the make-whole price determined in accordance with the indenture. On or after March 15, 2004, we may redeem the 8.5% senior notes at the redemption prices set forth in the indenture and prior to such date pursuant to make-whole provisions in the indenture. We may redeem the 8.125% senior notes at any time on or after April 1, 2006 at the redemption prices set forth in the indenture and prior to such date pursuant to make-whole provisions in the indenture. We may redeem the 8.375% senior notes at any time on or after November 1, 2005 at the redemption prices set forth in the indenture and prior to such date pursuant to make-whole provisions in the indenture. If we repurchase at least an additional $53 million of the 7.875% senior notes by August 31, 2003, we may extend the bank credit facility until June 2005 for an amount equal to the total revolving credit facility commitment less the outstanding amount of the 7.875% senior notes plus $50 million.

The indentures for the 8.125% and 8.375% senior notes contain covenants limiting our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not affect our ability to borrow under or expand our secured credit facility. As of March 31, 2002, we estimate that secured commercial bank indebtedness of approximately $397 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., an unrestricted subsidiary.

Some of our commodity price and interest rate risk management arrangements require us to deliver cash collateral or other assurances of performance to the counterparties in the event that our payment obligations with respect to our commodity price and interest rate risk management transactions exceed certain levels. At March 31, 2002, we had posted $20.0 million of collateral with one of our counterparties. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and the level of volatility in natural gas and oil prices and interest rates.

Investing and Financing Transactions

In private transactions completed in the fourth quarter of 2001 and the Current Quarter, we acquired 7.65% of the outstanding common stock of Canaan Energy Corporation, an oil and gas exploration and production company, for cash consideration totaling $4.0 million, or $12.00 per share. On April 19, 2002, we entered into an agreement and plan of merger pursuant to which we will acquire Canaan Energy Corporation in a cash merger through a Chesapeake subsidiary. Under the agreement, all outstanding common shares of Canaan, other than the Canaan shares owned by Chesapeake and those that dissent, will be converted into the right to receive $18.00 per share in cash, and outstanding options to acquire Canaan common stock will be converted into the right to receive, for each share of Canaan common stock to be received upon exercise, the merger consideration less the per share exercise price and withholding taxes. We expect the aggregate net cash consideration for the merger will be $118 million, including the retirement of Canaan's outstanding indebtedness of approximately $33 million (net of stock option proceeds and working capital). The acquisition is subject to approval by Canaan's shareholders. Canaan's management and directors have agreed to vote their 1.2 million common shares in favor of the agreement. These shares, together with the Canaan shares we own, represent 37% of Canaan's outstanding common shares. The merger is expected to close in the third quarter of 2002. Under certain circumstances, Canaan has agreed to provide Chesapeake with a $5.0 million break-up fee in the event the transaction is not completed. We intend to pay for the transaction with cash on hand.

We value Canaan's estimated 100 bcfe of proved reserves at $1.14 per mcfe after allocation of $4 million of the purchase price to Canaan's undeveloped leasehold inventory and other assets. Canaan's proved reserves are 91% natural gas, 74% proved developed and are located almost exclusively in Chesapeake's core Mid-Continent operating area. Based on current production rates of 21,000 mcfe per day (approximately 8 bcfe per year), Canaan's reserves-to-production ratio is 12.5.

In the Current Quarter, we purchased and subsequently retired $21.0 million of our 7.875% senior notes due 2004 for total consideration of $21.9 million, including accrued interest of $0.5 million and $0.4 million of redemption premium. In April 2002, we purchased and retired an additional $1.0 million of these notes for $1.0 million including accrued interest.

See Note 2 of the notes to consolidated financial statements included in this report for a discussion of our hedging activities and financial instruments.

RECENTLY ISSUED ACCOUNTING STANDARDS

See Note 8 of the notes to the consolidated financial statements included in this report for a summary of recently issued accounting standards.

FORWARD-LOOKING STATEMENTS

This report includes "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. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and gas reserve estimates, planned capital expenditures, the drilling of oil and gas wells and future acquisitions, expected oil and gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations, expected future expenses and utilization of net operating loss carryforwards. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1 of our Form 10-K for the year ended December 31, 2001. These factors include:

- the volatility of oil and gas prices,
- our substantial indebtedness,
- the cost and availability of drilling and production services,
- our commodity price risk management activities, including counterparty contract performance risk,
- uncertainties inherent in estimating quantities of oil and gas reserves, projecting future rates of production and the timing of development expenditures,
- our ability to replace reserves,
- the availability of capital,

- uncertainties in evaluating oil and gas reserves of acquired properties and associated potential liabilities,
- drilling and operating risks,
- our ability to generate future taxable income sufficient to utilize our NOLs before expiration,
- future ownership changes which could result in additional limitations to our NOLs,
- adverse effects of governmental and environmental regulation,
- losses possible from pending or future litigation,
- the strength and financial resources of our competitors, and
- the loss of officers or key employees.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this and our other reports filed with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

OIL AND GAS HEDGING ACTIVITIES

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of this exposure to adverse market changes, we have entered into derivative instruments. As of March 31, 2002, our derivative instruments were comprised of swaps, collars, cap-swaps, straddles, strangles and basis protection swaps. These instruments allow us to predict with greater certainty the effective oil and gas prices to be received for our hedged production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price, as defined in each instrument, to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, then we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, then no payments are due from either party.
- For cap-swaps, we receive a fixed price for the hedged commodity and pay a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a "cap" limiting the counterparty's exposure.
- For straddles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option which establish a fixed price. To the extent that the market price differs from the

established fixed price, Chesapeake pays the counterparty.

- For strangles, Chesapeake receives a premium from the counterparty in exchange for the sale of a call and a put option. If the market price exceeds the fixed price of the call option or falls below the fixed price of the put option, then Chesapeake pays the counterparty. If the market price settles between the fixed price of the call and put option, no payment is due from Chesapeake.

- Basis protection swaps are arrangements that guarantee a price differential of oil and gas from a specified delivery point. Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

From time to time, we close certain swap transactions designed to hedge a portion of our oil and natural gas production by entering into a counter-swap instrument. Under the counter-swap we receive a floating price for the hedged commodity and pay a fixed price to the counterparty. To the extent the counter-swap is designed to lock the value of an existing SFAS 133 cash flow hedge, the net value of the swap and the counter-swap is frozen and shown as a derivative receivable or payable in the consolidated balance sheets. At the same time, the original swap is designated as a non-qualifying cash flow hedge under SFAS 133.

Pursuant to SFAS 133, our cap-swaps, straddles, strangles, counter-swaps and basis protection swaps do not qualify for designation as cash flow hedges. Therefore, changes in the fair value of these instruments that occur prior to their maturity, together with any changes in fair value of cash flow hedges resulting from ineffectivness, are reported in the consolidated statements of operations as risk management income (loss). Amounts recorded in risk management income (loss) do not represent cash gains or losses. Rather, these amounts are temporary valuation swings in contracts or portions of contracts that are not entitled to receive SFAS 133 cash flow hedge accounting treatment. All amounts initially recorded in this caption are ultimately reversed within this same caption and included in oil and gas sales over the respective contract terms.

As of March 31, 2002, we had the following open oil and gas derivative instruments designed to hedge a portion of our gas production for periods after March 2002:

	VOLUME	AVERAGE STRIKE PRICE	WEIGHTED-AVERAGE PUT STRIKE PRICE	WEIGHTED-AVERAGE CALL STRIKE PRICE	WEIGHTED-AVERAGE DIFFERENTIAL	SFAS 133 HEDGE	P R
NATURAL GAS (mmbtu):							
Swaps:							
2002................	29,560,000	$ 2.85	$ --	$ --	$ --	Yes	$
2003................	2,700,000	3.03	--	--	--	Yes	

Cap-Swaps:							
2002................	63,870,000	4.54	3.54	--	--	No	
2003................	51,100,000	3.60	2.60	--	--	No	
Collars:							
2002................	9,780,000	--	4.00	5.42	--	Yes	
Straddles:							
2002................	24,420,000	--	2.37	2.37	--	No	
Strangles:							
2003................	14,600,000	--	3.20	3.70	--	No	
2004................	14,640,000	--	3.40	3.90	--	No	
Basis Protection Swaps:							
2003................	91,250,000	--	--	--	(0.15)	No	
2004................	91,500,000	--	--	--	(0.15)	No	
2005................	91,250,000	--	--	--	(0.16)	No	
Counter-Swaps:							
2003................	16,500,000	3.68	--	--	--	No	
Locked Swaps:							
2002................	--	--	--	--	--	No	
2003................	--	--	--	--	--	No	
TOTAL GAS							
OIL (bbls):							
Cap-Swaps:							
2002................	1,650,000	24.97	20.19	--	--	No	
Locked-Swaps:							
2002................	--	--	--	--	--	No	
TOTAL OIL	--	--	--	--	--	--	
TOTAL GAS AND OIL							$

(a) After adjusting for the $40.9 million premium paid to Chesapeake by the counterparty at the inception of the straddle and strangle contracts (which is recorded in cash provided by operating activities), the net value of the combined hedging portfolio at March 31, 2002 was $37.5 million.

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at March 31, 2002.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows ($ in thousands):

Fair value of contracts outstanding at January 1, 2002	$ 157,309
Change in fair value of contracts during period	(69,712)
Contracts realized or otherwise settled during the period	(48,554)
Fair value of new contracts when entered into during the period	(42,530)
Changes in fair values attributable to changes in valuation techniques and assumptions	--
Fair value of contracts outstanding at March 31, 2002	$ (3,487)

Risk management loss related to our oil and gas derivatives for the three months ended March 31, 2002 is comprised of the following ($ in thousands):

Risk Management Loss:	
Change in fair value of derivatives not qualifying for hedge accounting	$ (53,414)
Reclassification of settled contracts	(25,077)
Ineffective portion of derivatives qualifying for hedge accounting	(824)
Total	$ (79,315)

Although derivatives often fail to achieve 100% effectiveness for accounting purposes, our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

The change in the fair value of our derivative instruments since January 1, 2002 resulted from an increase in market prices for natural gas and crude oil. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and gas as of the consolidated balance sheet dates. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

We expect to transfer approximately $12.9 million of the balance in accumulated other comprehensive income, based upon the market prices at March 31, 2002, to earnings during the next 12 months when the forecasted transactions actually occur. All forecasted transactions hedged as of March 31, 2002 are expected to mature by December 2005.

INTEREST RATE

We also utilize hedging strategies to manage interest rate exposure. In March 2002, we entered into an interest rate swap to convert a portion of our fixed rate debt to floating rate debt. The terms of the swap agreement are as follows:

MONTHS	NOTIONAL AMOUNT	FIXED RATE	FLOATING R

March 2002 - March 2004	$200,000,000	7.875%	U.S. six-month arrears plus 2 points

If the floating rate is less than the fixed rate, the counterparty will pay us accordingly. If the floating rate exceeds the fixed rate, we will pay the counterparty. Payments under the interest rate swap coincide with the semi-annual interest payments on our 7.875% senior notes which are due on September 15 and March 15 of each year beginning September 15, 2002.

A portion of the interest rate swap was entered into to convert $129 million of the 7.875% senior notes from fixed rate debt to variable rate debt. Under SFAS 133, a hedge of the interest rate risk in a recognized fixed rate liability can be designated as a fair value hedge. Accordingly, the mark-to-market value of the swap is recorded on the consolidated balance sheets as an asset or liability with a corresponding increase or decrease to the debt's carrying value.

The remaining $71 million of the interest rate swap has not been designated as a fair value hedge. The mark-to-market value of this portion of the instrument is recorded as a derivative asset or liability on the consolidated balance sheets with the offsetting amount reflected in risk management income (loss) on the consolidated statements

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of operations. The amount recorded in risk management income (loss) will be reversed and reflected in interest expense when the swap is settled.

The estimated fair value of the interest rate swap at March 31, 2002 was a liability of approximately $0.4 million comprised of $0.2 million reflected as risk management loss and $0.2 million reflected as a reduction to long-term debt. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the swap agreement.

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. The fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	MARCH 31, 2002					
	YEARS OF MATURITY					
	2002	2003	2004	2005	2006	TH
	($ IN MILLIONS)					
LIABILITIES:						
Long-term debt, including current portion--fixed rate	$ 0.4	$ --	$ 129.0	$ --	$ --	$
Average interest rate	9.1%	--	7.9%	--	--	
Long-term debt--variable rate	$ --	$ --	$ --	$ --	$ --	$
Average interest rate	--	--	--	--	--	

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(1) This amount does not include the discount of ($13.0) million included in long-term debt and the value of the interest rate swap of ($0.2) million which qualifies for SFAS 133 fair value hedge accounting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are subject to ordinary routine litigation incidental to our business, none of which is expected to have a material adverse effect on Chesapeake. In addition, Chesapeake is a defendant in other pending actions which are described in Note 3 of the notes to the consolidated financial statements included in this report and Item 3 of our Annual Report on Form 10-K for the year ended December 31, 2001.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

Not applicable

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable

ITEM 5. OTHER INFORMATION

Not applicable

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits

The following exhibits are filed as a part of this report:

EXHIBIT NUMBER	DESCRIPTION
4.6.1	Consent and waiver letter dated April 15, 2002 with respect to Second Amended and Restated Credit Agreement, dated as of June 11, 2001, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Bear Stearns Corporate Lending Inc., as Syndication Agent, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, and other lenders party thereto.
10.1.11	Registrant's 2002 Nonqualified Stock Option Plan

(b) Reports on Form 8-K

During the quarter ended March 31, 2002, we filed the following current reports on Form 8-K:

On January 22, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release declaring a quarterly cash dividend on our preferred stock.

On February 5, 2002 we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing fourth quarter and 2001 full-year earnings release and conference call dates.

On February 21, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing strong 2001 results with cash flow, EBITDA and production setting records. The press release also contained information on 2001 finding costs, proved reserves, our hedging program, exploration activities and an overview of results for the past three years. We furnished under Item 9 updates to our full year 2002 forecasts, cap-ex budget and balance sheet goals.

On March 12, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing a proposal to acquire Canaan Energy Corporation for $12.00 per share in cash.

On March 18, 2002, we filed a current report on Form 8-K reporting under Item 5 that we had issued a press release announcing that we were deferring our tender offer for the outstanding shares of Canaan Energy Corporation pending discussions with Canaan management.

SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION
(Registrant)

By: /s/ AUBREY K. MCCLENDON

Aubrey K. McClendon
Chairman and Chief Executive Officer

By: /s/ MARCUS C. ROWLAND

Marcus C. Rowland
Executive Vice President and
Chief Financial Officer

Date: May 15, 2002

INDEX TO EXHIBITS

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10.1.11	Registrant's 2002 Nonqualified Stock Option Plan