UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q/A

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

For the quarterly period ended June 30, 2003

¨ **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	**73-1395733**
(State or other jurisdiction	**(I.R.S. Employer**
of incorporation or organization)	**Identification No.)**
6100 North Western Avenue	**73118**

Oklahoma City, Oklahoma
(Address of principal executive offices) **(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 ¨

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). YES x NO ¨

At August 11, 2003, there were 216,057,569 shares of our $0.01 par value common stock outstanding.

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AMENDMENT NO. 1

EXPLANATORY NOTE

As described in Note 11 to the Condensed Consolidated Financial Statements, Chesapeake Energy Corporation has reclassified certain amounts previously reported Condensed Consolidated Statement of Operations and has made the corresponding revisions to the Notes to Consolidated Financial Statements for the three and six months ended June 30, 2003 and 2002. The revisions had no effect on previously reported net income or net income per share.

Corresponding changes resulting from these revisions of classifications in the financial statements were also made to Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and Item 3. Quantitative and Qualitative Disclosures About Market Risk .

In light of the refiling of this report for the purpose of revising the financial statements, we have also revised other disclosures from the original filing in response to comments of the staff of the Securities and Exchange Commission.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2003

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2003	December 31, 2002
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 35,909	$ 247,637
Restricted cash		82
Accounts receivable:		
Oil and gas sales	190,453	109,246
Joint interest, net of allowance of $2,644,000 and $1,433,000, respectively	24,973	22,760
Short-term derivatives	342	16,498
Related parties	3,853	2,155
Other	27,647	13,471
Deferred income tax asset	6,479	8,109
Short-term derivative instruments	31,331	
Inventory and other	12,480	15,359
Total Current Assets	333,467	435,317
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full cost accounting:		
Evaluated oil and gas properties	5,575,048	4,334,833
Unevaluated properties	177,837	72,506
Less: accumulated depreciation, depletion and amortization	(2,280,690)	(2,123,773)
	3,472,195	2,283,566
Other property and equipment	175,817	154,092
Less: accumulated depreciation and amortization	(52,846)	(47,774)
Total Property and Equipment	3,595,166	2,389,884
OTHER ASSETS:		
Deferred income tax asset		2,071
Long-term derivative instruments	24,873	2,666
Long-term investments	29,075	9,075
Other assets	30,779	36,595
Total Other Assets	84,727	50,407
TOTAL ASSETS	$ 4,013,360	$ 2,875,608
LIABILITIES AND STOCKHOLDERS EQUITY		

CURRENT LIABILITIES:		
Accounts payable	$ 128,579	$ 86,001
Accrued interest	47,787	35,025
Derivative payable	2,296	
Short-term derivative instruments	42,384	33,697
Other accrued liabilities	83,665	56,465
Revenues and royalties due others	111,160	54,364
Total Current Liabilities	415,871	265,552
OTHER LIABILITIES:		
Long-term debt, net	1,968,447	1,651,198
Revenues and royalties due others	14,882	13,797
Long-term derivative instruments	3,442	30,174
Asset retirement obligation	44,699	
Other liabilities	10,479	7,012
Deferred income taxes payable	92,068	
Total Other Liabilities	2,134,017	1,702,181
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $0.01 par value, 10,000,000 shares authorized, 6.75% cumulative convertible preferred stock, 2,998,000 shares issued and outstanding at June 30, 2003 and December 31, 2002, entitled in liquidation to $149.9 million	149,900	149,900
6.00% cumulative convertible preferred stock, 4,600,000 and 0 shares issued and outstanding at June 30, 2003 and December 31, 2002, entitled in liquidation to $230.0 million	230,000	
Common Stock, $.01 par value, 350,000,000 shares authorized, 220,933,661 and 194,936,912 shares issued at June 30, 2003 and December 31, 2002, respectively	2,209	1,949
Paid-in capital	1,387,352	1,205,554
Accumulated deficit	(296,644)	(426,085)
Accumulated other comprehensive income (loss), net of tax of $(7,812,000) and $2,307,000, respectively	12,746	(3,461)
Less: treasury stock, at cost; 5,071,571 and 4,792,529 common shares at June 30, 2003 and December 31, 2002, respectively	(22,091)	(19,982)
Total Stockholders Equity	1,463,472	907,875
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 4,013,360	$ 2,875,608

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	($ in thousands, except per share data) (Revised Note 11)			
REVENUES:				
Oil and gas sales	$ 319,519	$ 150,905	$ 605,538	$ 213,561
Oil and gas marketing sales	110,296	42,785	200,604	70,118
Total Revenues	429,815	193,690	806,142	283,679
OPERATING COSTS:				
Production expenses	34,263	24,242	65,720	46,302
Production taxes	17,101	7,911	35,698	13,127
General and administrative	6,000	3,859	11,665	8,153
Oil and gas marketing expenses	106,857	41,181	196,215	67,688
Oil and gas depreciation, depletion and amortization	91,570	50,778	168,184	99,397
Depreciation and amortization of other assets	4,122	3,652	7,806	6,762
Total Operating Costs	259,913	131,623	485,288	241,429
INCOME FROM OPERATIONS	169,902	62,067	320,854	42,250
OTHER INCOME (EXPENSE):				
Interest and other income	781	3,992	1,544	5,537
Interest expense	(38,036)	(24,067)	(75,040)	(51,180)
Loss on repurchases of Chesapeake debt		(273)		(864)
Total Other Income (Expense)	(37,255)	(20,348)	(73,496)	(46,507)
INCOME (LOSS) BEFORE INCOME TAX AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	132,647	41,719	247,358	(4,257)
INCOME TAX EXPENSE (BENEFIT):				
Current				
Deferred	50,407	16,686	93,998	(1,704)
Total Income Tax Expense (Benefit)	50,407	16,686	93,998	(1,704)
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	82,240	25,033	153,360	(2,553)
Cumulative effect of accounting change, net of income taxes of $1,464,000			2,389	

NET INCOME (LOSS)	82,240	25,033	155,749	(2,553)
Preferred stock dividends	(5,979)	(2,530)	(9,505)	(5,062)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 76,261	$ 22,503	$ 146,244	$ (7,615)
EARNINGS (LOSS) PER COMMON SHARE BASIC:				
Income (loss) before cumulative effect of accounting change	$ 0.36	$ 0.14	$ 0.70	$ (0.05)
Cumulative effect of accounting change			0.01	
Net income (loss)	$ 0.36	$ 0.14	$ 0.71	$ (0.05)
EARNINGS (LOSS) PER COMMON SHARE ASSUMING DILUTION:				
Income (loss) before cumulative effect of accounting change	$ 0.31	$ 0.13	$ 0.62	$ (0.05)
Cumulative effect of accounting change			0.01	
Net income (loss)	$ 0.31	$ 0.13	$ 0.63	$ (0.05)
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):				
Basic	214,341	165,963	205,995	165,669
Assuming dilution	263,919	191,947	247,391	165,669

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
	2003	**2002**
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$ 155,749	$ (2,553)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	172,543	103,770
Unrealized (gains) losses on derivatives	(30,794)	79,949
Deferred income taxes	93,998	(1,702)
Amortization of loan costs and bond discount	4,110	2,899
Cumulative effect of accounting change	(2,389)	
Other	565	167
Cash provided by operating activities before changes in assets and liabilities	393,782	182,530
Changes in assets and liabilities	(17,149)	32,295
Cash provided by operating activities	376,633	214,825
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of oil and gas properties	(307,090)	(176,386)
Acquisition of unproved oil and gas properties	(123,122)	(7,167)
Acquisition of proved oil and gas properties	(863,050)	(124,305)
Sales of proved oil and gas properties	19,667	
Investment in Pioneer Drilling Company	(20,000)	
Additions to other property, plant and equipment and other	(22,179)	(16,714)
Cash used in investing activities	(1,315,774)	(324,572)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	296,000	45,000
Payments on long-term borrowings	(270,000)	
Cash received from issuance of senior notes	297,306	
Cash paid for issuance costs of senior notes	(6,367)	
Proceeds from issuance of preferred stock, net of issuance costs	222,893	
Proceeds from issuance of common stock, net of issuance costs	177,444	
Net increase in outstanding payments in excess of cash balances	29,474	
Cash paid for common stock dividend	(12,125)	
Cash paid for preferred stock dividend	(8,893)	(5,118)
Cash paid to repurchase senior notes		(43,220)
Cash paid for treasury stock	(2,109)	
Cash received from exercise of stock options and warrants	6,326	1,956
Other	(2,536)	(169)

Cash provided by (used in) financing activities	727,413	(1,551)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(211,728)	(111,298)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	247,637	117,594
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 35,909	$ 6,296

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	($ in thousands)			
Net income (loss)	$ 82,240	$ 25,033	$ 155,749	$ (2,553)
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments	11,696	(2,242)	(36,859)	(12,972)
Reclassification of (gain) or loss on settled contracts	2,461	(1,683)	53,352	(15,769)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	(256)	815	(286)	1,309
Comprehensive income (loss)	$ 96,141	$ 21,923	$ 171,956	$ (29,985)

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Summary of Significant 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 and six months ended June 30, 2003 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2002 (the Prior Quarter and Prior Period , respectively) and the three and six months ended June 30, 2003 (the Current Quarter and Current Period , respectively).

Stock Options

Chesapeake has elected to follow APB No. 25, *Accounting for Stock Issued to Employees,* and related interpretations in accounting for its employee stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. In March 2000, the Financial Accounting Standards Board issued FASB Interpretation No. 44 which provided clarification regarding the application of APB No. 25. FIN 44 specifically addressed the accounting consequences of various modifications to the terms of a previously granted fixed price stock option. Pursuant to FIN 44, we recognized no compensation adjustment in the Prior Quarter and compensation expense of $387,900, $365,300 and $162,500 in the Current Quarter, the Current Period and the Prior Period, respectively, as a result of modifications to fixed-price stock options that were made during the years ended December 31, 2001 and 2000. No compensation income or expense has been recognized for stock options issued in 2003 or 2002 because the exercise price of the stock options granted under the plans equaled the market price of the underlying stock on the date of grant and there have been no modifications to these options.

Presented below is pro forma financial information assuming that Chesapeake had applied the fair value method under SFAS No. 123:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	2002	2003	2002
	($ in thousands)			
Net Income (Loss)				
As reported [(1)]	$ 82,240	$ 25,033	$ 155,749	$ (2,553)

Compensation expense, net of tax	(2,539)	(2,088)	(5,014)	(4,155)
Pro forma	$ 79,701	$ 22,945	$ 150,735	$ (6,708)
Basic earnings (loss) per common share				
As reported	$ 0.36	$ 0.14	$ 0.71	$ (0.05)
Compensation expense, net of tax	(0.01)	(0.01)	(0.02)	(0.02)
Pro forma	$ 0.35	$ 0.13	$ 0.69	$ (0.07)
Diluted earnings (loss) per common share				
As reported	$ 0.31	$ 0.13	$ 0.63	$ (0.05)
Compensation expense, net of tax	(0.01)	(0.01)	(0.02)	(0.02)
Pro forma	$ 0.30	$ 0.12	$ 0.61	$ (0.07)

(1) Net income includes adjustments related to FIN 44 of $387,900, $365,300 and $162,500 of expense in the Current Quarter, the Current Period and the Prior Period, respectively.

For purposes of the pro forma disclosures, the estimated fair value of the options is amortized to expense over the options vesting period, which is four years. Because our stock options vest over four years and additional awards are typically made each year, the above pro forma disclosures are not likely to be representative of the effects on pro forma net income for future quarters.

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Critical Accounting Policies

We consider accounting policies related to stock options, hedging, oil and gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2002, except for our accounting policy related to stock options which is summarized in Note 1 of the notes to the consolidated financial statements included in our annual report on Form 10-K.

Statement of Financial Accounting Standards No. 141, *Business Combinations* and Statement of Financial Accounting Standards No. 142, *Goodwill and Intangible Assets* were issued by the Financial Accounting Standards Board in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method. Additionally, SFAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment.

Oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may have to be classified separately from oil and gas properties as intangible assets on our condensed consolidated balance sheets. In addition, the disclosures required by SFAS 141 and 142 relative to intangibles would be included in the notes to the condensed consolidated financial statements. Historically, we, like many other oil and gas companies, have included these rights as part of oil and gas properties, even after SFAS 141 and 142 became effective.

As it applies to companies like us that have adopted full cost accounting for oil and gas activities, we understand that this interpretation of SFAS 141 and 142 would only affect our balance sheet classification of proved oil and gas leaseholds acquired after June 30, 2001 and all of our unproved oil and gas leaseholds. We would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because we did not separately value or account for these costs prior to the adoption date of SFAS 141. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and gas reserves would continue to be amortized in accordance with full cost accounting rules.

As of June 30, 2003 and December 31, 2002, we had undeveloped leaseholds of approximately $177.8 million and $72.5 million, respectively, that would be classified on our condensed consolidated balance sheet as intangible undeveloped leasehold and developed leaseholds of an estimated $1,423.0 million and $581.9 million, respectively, that would be classified as intangible developed leasehold if we applied the interpretation discussed above.

We will continue to classify our oil and gas mineral rights held under lease and other contractual rights representing the right to extract such reserves as tangible oil and gas properties until further guidance is provided.

2. Financial Instruments and Hedging Activities

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 the exposure to adverse market changes, we have entered into various derivative instruments. As of June 30, 2003, our oil and gas derivative instruments were comprised of swaps, cap-swaps 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. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify

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for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written option do not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.

Basis protection swaps are arrangements that guarantee a price differential of oil or 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.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap or cap-swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that, collectively, the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

When Chesapeake enters into a counter-swap with the same counterparty, to the extent that a right of setoff exists in accordance with FASB Interpretation No. 39, we net the value of the swap and the counter-swap.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of a counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in the value of the corresponding counter-swap.

Chesapeake enters into oil and gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and gas commodity prices. Accordingly, we believe that any associated gains or losses from the derivative transactions should be reflected as adjustments to oil and gas sales on the condensed consolidated statement of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and gas sales. Unrealized gains (losses) included in oil and gas sales in the Current Period and Prior Period were $33.0 million and ($80.4) million, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in other comprehensive income. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. These amounts totaled to a gain of $0.5 million in the Current Period and a loss of $2.2 million in the Prior Period, a gain of $0.4 million in the Current Quarter and a loss of $1.4 million in the Prior Quarter.

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The estimated fair values of our oil and gas derivative instruments as of June 30, 2003 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2003
	($ in thousands)
Derivative assets (liabilities):	
Fixed-price gas swaps	$ 21,393
Fixed-price gas cap-swaps	(49,558)
Fixed-price gas counter-swaps	45,799
Fixed-price gas locked swaps	(1,429)
Gas basis protection swaps	33,429
Fixed-price crude oil cap-swaps	(3,431)
Estimated fair value	$ 46,203

Based upon the market prices at June 30, 2003, we expect to transfer approximately $13.7 million of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the hedged transactions actually close. All transactions hedged as of June 30, 2003 will mature by 2007, with the exception of the basis protection swaps which extend to 2009.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows:

	2003
	($ in thousands)
Fair value of contracts outstanding at January 1	$ (14,533)
Change in fair value of contracts during the period	(30,952)
Contracts realized or otherwise settled during the period	91,688
Fair value of new contracts when entered into during the period	
Fair value of contracts outstanding at June 30	$ 46,203

Interest Rate Hedging

We also utilize hedging strategies to manage interest rate exposure. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

In July 2002, we closed two interest rate swaps for a cash settlement of $8.6 million. As of June 30, 2003, the remaining balance to be amortized as a reduction to interest expense was $0.4 million. During the Current Quarter and Current Period, $0.2 million and $0.3 million, respectively, was recorded as a reduction to interest expense.

In March 1997, Chesapeake issued $150.0 million of 8.5% senior notes due 2012, of which $7.3 million were subsequently repurchased and retired. The 8.5% senior notes include a call option whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. This call option, also referred to as a right of optional redemption, allows Chesapeake to redeem the notes prior to their stated maturity date beginning in March 2004. This right of optional redemption has value depending upon changes in interest rates. Due to a decline in interest rates, Chesapeake effectively sold this optional redemption right to an unrelated third party (or counterparty) for $7.8 million in April 2002. In exchange for $7.8 million, Chesapeake gave the counterparty the option to elect whether or not to enter into an interest rate swap with Chesapeake on March 11, 2004. This transaction is more commonly referred to as a swaption. The terms of the interest rate swap, if executed by the counterparty, would be as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004 March 2012	$142,665,000	8.5%	U.S. six-month LIBOR plus 75 basis points

The interest rate swap would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap on March 11, 2004, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

This transaction does not alter Chesapeake s ability to redeem the 8.5% senior notes. Instead, it locks-in the economics of a future call. If interest rates are high and the swaption is not in-the-money , the counterparty will likely not elect to enter into the interest rate swap, the swaption will expire, and Chesapeake will amortize the $7.8

million premium as a reduction to interest expense over the remaining life of the notes. If interest rates are low and the swaption is in-the-money , the counterparty will likely exercise the swaption and force Chesapeake to settle the transaction at the then current value of the interest rate swap, and Chesapeake will amortize both the $7.8 million premium and the amount paid to the counterparty to interest expense over the remaining life of the notes. If Chesapeake elects to refinance the 8.5% senior notes, any unamortized premium or loss remaining related to the swaption would be included in the gain (or loss) on the early extinguishment of debt.

According to SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and the swaption agreement. The fair value of the swaption is recorded on the condensed consolidated balance sheets as a liability, and the debt s carrying amount is adjusted by the change in the fair value of the call option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense.

We have recorded an adjustment to the carrying amount of the debt of $25.3 million as of June 30, 2003. Since the inception of the swaption, we recorded the change in the fair market value of the swaption from a $7.8 million liability to a $37.8 million liability, an increase of $30.0 million. As part of recording the fair value hedge, we also recorded, as an adjustment to the carrying value of the debt, a $25.3 million increase in the fair value of the embedded call option. The difference between the two adjustments, $4.7 million representing ineffectiveness, was recorded as additional interest expense. Results of the interest rate swap, if initiated, will be reflected as adjustments to interest expense in the corresponding months.

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 values 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, fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt, excluding the value of the interest rate swaps and the call option on the 8.5% senior notes, at June 30, 2003 and December 31, 2002 was $1,967.3 million and $1,669.3 million, respectively, compared to approximate fair values of $2,131.3 million and $1,744.7 million, respectively. The carrying amount for our 6.75% convertible preferred stock at June 30, 2003 and December 31, 2002 was $149.9 million, with a fair value of $227.1 million and $181.5 million, respectively. The carrying amount of our 6.00% convertible preferred stock was $230.0 million which approximated its fair value as of June 30, 2003.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in cash and cash equivalents 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 and equity instruments and accounts receivable. 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 and may at times exceed the federally insured limits.

3. Contingencies and Commitments

Royalty Owner Litigation. Royalty owners have commenced litigation against a number of oil and gas producers claiming that amounts paid for production attributable to the royalty owners interest violated the terms of applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the leases, and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. Typically this litigation has taken the form of class action suits. There are presently four such suits filed against Chesapeake, two in Texas and two in Oklahoma. No class has been certified in any of them. In one of the

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Oklahoma cases, we determined that a portion of the marketing fee we had charged royalty owners should be refunded. We have deposited with the court the aggregate amount of the fees we estimated should be refunded, $3.6 million, in an interest-bearing account for distribution to affected royalty owners. This amount has been charged to general and administrative expenses, of which $0.3 million was charged in the Current Period and the remainder was recorded in 2002. We do not believe any other claims made by royalty owners in the cases pending against us are valid. Even if the claims were upheld, we believe any damages awarded would not be material. This is a developing area of the law, however, and as new cases are decided, our potential liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor court decisions to ensure that our operations and practices minimize any exposure and to recognize any charges that may be appropriate when we can reasonably estimate a liability.

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 our consolidated financial position or results of operations.

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and various other senior management personnel, which provide for annual base salaries, bonus compensation and various benefits. The agreements provide for the continuation of salary and benefits for varying terms in the event of termination of employment without cause. The agreements with the chief executive officer and chief operating officer have terms of five years commencing July 1, 2002. The term of each agreement is automatically extended for one additional year on each June 30 unless one of the parties provides 30 days notice of non-extension. The agreements with the chief financial officer and other senior managers expire on June 30, 2006. The company s employment agreements for executive officers provide for payments in the event of a change of control. The chief executive officer and chief operating officer are each entitled to receive a payment in the amount of five times his base compensation and the prior year s benefits, plus a tax gross-up payment, and the chief financial officer and other officers are each entitled to receive a payment in the amount of his or her base compensation plus bonuses paid during the prior year.

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 conducts periodic reviews, on a company-wide basis, to identify changes in its environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume the liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at June 30, 2003.

4. Net Income (Loss) 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 Prior Quarter, the Current Quarter, the Prior Period and the Current Period, outstanding warrants to purchase 1.1 million, 0.4 million, 1.1 million and 0.4 million shares of common stock at a weighted-average exercise price of $12.61, $14.55, $12.61 and $14.55, respectively, were antidilutive because the exercise prices of the warrants were greater than the average market price of the common stock.

For the Prior Quarter, the Current Quarter, the Prior Period and the Current Period, outstanding options to purchase 0.3 million, 0.4 million, 0.4 million and 0.3 million shares of common stock at a weighted-average exercise price of $15.30, $15.47, $14.44 and $16.33, 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 Prior Period s net loss to common shareholders, the diluted shares do not include the effect of outstanding stock options to purchase 5.9 million shares of common stock at a weighted-average exercise price of $3.90, the assumed conversion of the outstanding 6.75% preferred stock (convertible into 19.5 million common shares), the common stock equivalent of preferred stock outstanding prior to conversion (11,480 shares), or warrants to purchase 6,574 shares of common stock at a weighted-average exercise price of $0.05 as the effects were antidilutive.

A reconciliation for the three months ended June 30, 2003 and 2002 and the six months ended June 30, 2003 is as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Three Months Ended June 30, 2003:			
Basic EPS			
Income available to common shareholders	$ 76,261	214,341	$ 0.36
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares outstanding during the period:			
Preferred dividends	5,979		
Common shares assumed issued for 6.00% preferred stock		22,358	
Common shares assumed issued for 6.75% preferred stock		19,468	
Employee stock options		7,752	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 82,240	263,919	$ 0.31
For the Three Months Ended June 30, 2002:			
Basic EPS			
Income available to common shareholders	$ 22,503	165,963	$ 0.14
Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares outstanding during the period:			
Preferred dividends	2,530		
Common shares assumed issued for 6.75% preferred stock		19,478	
Employee stock options		6,500	
Warrants assumed in Gothic acquisition		6	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 25,033	191,947	$ 0.13
For the Six Months Ended June 30, 2003:			
Basic EPS			
Income available to common shareholders	$ 146,244	205,995	$ 0.71

Effect of Dilutive Securities			
Assumed conversion at the beginning of the period of preferred shares outstanding during the period:			
Preferred dividends	9,505		
Common shares assumed issued for 6.00% preferred stock		14,576	
Common shares assumed issued for 6.75% preferred stock		19,468	
Employee stock options		7,352	
Diluted EPS			
Income available to common shareholders and assumed conversions	$ 155,749	247,391	$ 0.63

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5. Senior Notes and Revolving Credit Facility

At June 30, 2003, our long-term debt consisted of the following ($ in thousands):

7.875% senior notes, due 2004	$ 42,137(1)
8.375% senior notes, due 2008	250,000
8.125% senior notes, due 2011	800,000
8.500% senior notes, due 2012	142,665
9.000% senior notes, due 2012	300,000
7.500% senior notes, due 2013	300,000
7.750% senior notes, due 2015	150,000
Revolving bank credit facility	26,000
Discount on senior notes	(17,513)
Call option on 8.5% senior notes	(25,267)(2)
Interest rate swaps	425
Total	$ 1,968,447

(1) This amount has been classified as long-term debt based on our ability to satisfy this obligation with funding from our bank credit facility.
(2) See Note 2 of the notes to the condensed consolidated financial statements included in this report for further discussion on the call option.

On March 5, 2003, we issued $300.0 million principal amount of 7.50% senior notes due 2013, which have not been registered under the Securities Act of 1933**.**

On June 30, 2003, we had a $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. As of June 30, 2003, we had $26.0 million in outstanding borrowings under this facility and were using $25.3 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 our senior unsecured long-term debt ratings issued by Standard & Poor s Ratings Services and Moody s Investor Service. The unused portion of the facility is subject to an annual commitment fee also based on our senior unsecured long-term debt ratings. Interest is payable quarterly. The collateral value and borrowing base are redetermined periodically.

The credit agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans, purchase certain of our senior notes and create liens. The credit agreement requires us to maintain a current ratio of at least 1 to 1 (as defined in the credit facility) and a fixed charge coverage ratio for the trailing twelve month period of at least 2.5 to 1. At June 30, 2003, our current ratio was 1.6 to 1 and our fixed charge coverage ratio was 3.6 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. If such an acceleration involved principal in excess of $10.0 million, the acceleration 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 agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $25.0 million.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. The senior note indentures contain covenants limiting us and our guarantor subsidiaries with respect to asset sales; 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. We may redeem the senior notes at any time at specified make-whole or redemption prices as provided in the indentures.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding 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.

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

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CONDENSED CONSOLIDATED BALANCE SHEET

AS OF JUNE 30, 2003

($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents	$ (493)	$ 36,361	$ 41	$	$ 35,909
Accounts receivable	194,334	133,415	11,837	(92,660)	246,926
Short-term derivative receivable	342				342
Short-term derivative instruments	31,331				31,331
Deferred income tax asset			6,479		6,479
Inventory and other	10,724	1,746	10		12,480
Total Current Assets	236,238	171,522	18,367	(92,660)	333,467
PROPERTY AND EQUIPMENT:					
Evaluated oil and gas properties	5,575,048				5,575,048
Unevaluated properties	177,837				177,837
Other property and equipment	70,083	35,078	70,656		175,817
Less: accumulated depreciation, depletion and amortization	(2,306,654)	(21,910)	(4,972)		(2,333,536)
Net Property and Equipment	3,516,314	13,168	65,684		3,595,166
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances			718,661	(718,661)	
Long-term derivative instruments	24,873				24,873
Long-term investments			29,075		29,075
Other assets	9,141	24	21,638	(24)	30,779
Total Other Assets	34,014	24	769,374	(718,685)	84,727
TOTAL ASSETS	$ 3,786,566	$ 184,714	$ 853,425	$ (811,345)	$ 4,013,360
LIABILITIES AND STOCKHOLDERS EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 134,220	$ 130,846	$	$ (136,487)	$ 128,579
Accrued interest			47,787		47,787
Other accrued liabilities	66,750	2,922	13,708	285	83,665
Short-term derivative instruments	4,606		37,778		42,384
Derivative payable	2,296				2,296
Revenues and royalties due others	67,333			43,827	111,160
Total Current Liabilities	275,205	133,768	99,273	(92,375)	415,871

OTHER LIABILITIES:					
Long-term debt, net	26,000		1,942,447		1,968,447
Revenues and royalties due others	14,882				14,882
Long-term derivative instruments	3,442				3,442
Asset retirement obligation	44,699				44,699
Other liabilities	9,153	1,326			10,479
Deferred income tax liability (asset)	192,450	2,888	(103,270)		92,068
Intercompany payables (receivables)	2,549,075	(269)	(2,548,497)	(309)	
Total Other Liabilities	2,839,701	3,945	(709,320)	(309)	2,134,017
STOCKHOLDERS EQUITY:					
Common stock	56	1	2,209	(57)	2,209
Preferred stock			379,900		379,900
Other	671,604	47,000	1,081,363	(718,604)	1,081,363
Total Stockholders Equity	671,660	47,001	1,463,472	(718,661)	1,463,472
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 3,786,566	$ 184,714	$ 853,425	$ (811,345)	$ 4,013,360

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CONDENSED CONSOLIDATED BALANCE SHEET

AS OF DECEMBER 31, 2002

($ in thousands)

	Guarantor Subsidiary	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
ASSETS					
CURRENT ASSETS:					
Cash and cash equivalents, including restricted cash	$ (31,893)	$ 24,448	$ 255,164	$	$ 247,719
Accounts receivable	122,074	69,362	3,006	(46,810)	147,632
Short-term derivative receivable	16,498				16,498
Deferred income tax asset			8,109		8,109
Inventory and other	14,202	1,157			15,359
Total Current Assets	120,881	94,967	266,279	(46,810)	435,317
PROPERTY AND EQUIPMENT:					
Evaluated oil and gas properties	4,334,833				4,334,833
Unevaluated properties	72,506				72,506
Other property and equipment	64,475	30,818	58,799		154,092
Less: accumulated depreciation, depletion and amortization	(2,146,538)	(20,789)	(4,220)		(2,171,547)
Net Property and Equipment	2,325,276	10,029	54,579		2,389,884
OTHER ASSETS:					
Investments in subsidiaries and intercompany advances			357,698	(357,698)	
Deferred income tax asset (liability)	(124,455)	(1,941)	128,467		2,071
Long-term derivative instruments	2,666				2,666
Long-term investments			9,075		9,075
Other assets	20,246	57	16,349	(57)	36,595
Total Other Assets	(101,543)	(1,884)	511,589	(357,755)	50,407
TOTAL ASSETS	$ 2,344,614	$ 103,112	$ 832,447	$ (404,565)	$ 2,875,608
LIABILITIES AND STOCKHOLDERS EQUITY					
CURRENT LIABILITIES:					
Accounts payable	$ 82,083	$ 71,316	$	$ (67,398)	$ 86,001
Accrued interest			35,025		35,025
Other accrued liabilities	46,231	1,960	8,326	(52)	56,465
Short-term derivative instruments	33,697				33,697
Revenues and royalties due others	33,776			20,588	54,364
Total Current Liabilities	195,787	73,276	43,351	(46,862)	265,552

OTHER LIABILITIES:					
Long-term debt, net			1,651,198		1,651,198
Revenues and royalties due others	13,797				13,797
Long-term derivative instruments			30,174		30,174
Other liabilities	5,687	1,325			7,012
Intercompany payables (receivable)	1,801,833	(1,677)	(1,800,151)	(5)	
Total Other Liabilities	1,821,317	(352)	(118,779)	(5)	1,702,181
STOCKHOLDERS EQUITY:					
Common stock	56	1	1,949	(57)	1,949
Preferred stock			149,900		149,900
Other	327,454	30,187	756,026	(357,641)	756,026
Total Stockholders Equity	327,510	30,188	907,875	(357,698)	907,875
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,344,614	$ 103,112	$ 832,447	$ (404,565)	$ 2,875,608

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CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2003 (Revised Note 11):					
REVENUES:					
Oil and gas sales	$ 319,519	$	$	$	$ 319,519
Oil and gas marketing sales		336,392		(226,096)	110,296
Total Revenues	319,519	336,392		(226,096)	429,815
OPERATING COSTS:					
Production expenses	34,263				34,263
Production taxes	17,101				17,101
General and administrative	4,762	661	577		6,000
Oil and gas marketing expenses		332,953		(226,096)	106,857
Oil and gas depreciation, depletion and amortization	91,570				91,570
Depreciation and amortization of other assets	2,469	595	1,058		4,122
Total Operating Costs	150,165	334,209	1,635	(226,096)	259,913
INCOME (LOSS) FROM OPERATIONS	169,354	2,183	(1,635)		169,902
OTHER INCOME (EXPENSE):					
Interest and other income	(20)	372	41,080	(40,651)	781
Interest expense	(38,111)		(40,576)	40,651	(38,036)
Equity in net earnings of subsidiaries			82,942	(82,942)	
Total Other Income (Expense)	(38,131)	372	83,446	(82,942)	(37,255)
INCOME (LOSS) BEFORE INCOME TAXES	131,223	2,555	81,811	(82,942)	132,647
Income tax expense (benefit)	49,865	971	(429)		50,407
NET INCOME (LOSS)	$ 81,358	$ 1,584	$ 82,240	$ (82,942)	$ 82,240

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2002 (Revised Note 11):					

REVENUES:					
Oil and gas sales	$ 150,905	$	$	$	$ 150,905
Oil and gas marketing sales		138,964		(96,179)	42,785
Total Revenues	150,905	138,964		(96,179)	193,690
OPERATING COSTS:					
Production expenses	24,242				24,242
Production taxes	7,911				7,911
General and administrative	3,365	441	53		3,859
Oil and gas marketing expenses		137,360		(96,179)	41,181
Oil and gas depreciation, depletion and amortization	50,778				50,778
Other depreciation and amortization	2,484	493	675		3,652
Total Operating Costs	88,780	138,294	728	(96,179)	131,623
INCOME (LOSS) FROM OPERATIONS	62,125	670	(728)		62,067
OTHER INCOME (EXPENSE):					
Interest and other income	943	112	29,975	(27,038)	3,992
Interest expense	(26,061)	(8)	(25,036)	27,038	(24,067)
Loss on repurchases of Chesapeake debt			(273)		(273)
Equity in net earnings of subsidiaries			22,670	(22,670)	
Total Other Income (Expense)	(25,118)	104	27,336	(22,670)	(20,348)
INCOME BEFORE INCOME TAXES	37,007	774	26,608	(22,670)	41,719
Income tax expense	14,802	309	1,575		16,686
NET INCOME	$ 22,205	$ 465	$ 25,033	$ (22,670)	$ 25,033

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CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2003 (Revised Note 11):					
REVENUES:					
Oil and gas sales	$ 605,538	$	$	$	$ 605,538
Oil and gas marketing sales		630,543		(429,939)	200,604
Total Revenues	605,538	630,543		(429,939)	806,142
OPERATING COSTS:					
Production expenses	65,720				65,720
Production taxes	35,698				35,698
General and administrative	9,709	1,244	712		11,665
Oil and gas marketing expenses		626,154		(429,939)	196,215
Oil and gas depreciation, depletion and amortization	168,184				168,184
Depreciation and amortization of other assets	4,767	1,120	1,919		7,806
Total Operating Costs	284,078	628,518	2,631	(429,939)	485,288
INCOME (LOSS) FROM OPERATIONS	321,460	2,025	(2,631)		320,854
OTHER INCOME (EXPENSE):					
Interest and other income	(2)	466	76,745	(75,665)	1,544
Interest expense	(71,945)		(78,760)	75,665	(75,040)
Equity in net earnings of subsidiaries			158,630	(158,630)	
Total Other Income (Expense)	(71,947)	466	156,615	(158,630)	(73,496)
INCOME (LOSS) BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	249,513	2,491	153,984	(158,630)	247,358
Income tax expense (benefit)	94,816	947	(1,765)		93,998
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	154,697	1,544	155,749	(158,630)	153,360
Cumulative effect of accounting change, net of tax	2,389				2,389
NET INCOME (LOSS)	$ 157,086	$ 1,544	$ 155,749	$ (158,630)	$ 155,749

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated

For the Six Months Ended June 30, 2002 (Revised Note 11):					
REVENUES:					
Oil and gas sales	$ 213,561	$	$	$	$ 213,561
Oil and gas marketing sales		228,429		(158,311)	70,118
Total Revenues	213,561	228,429		(158,311)	283,679
OPERATING COSTS:					
Production expenses	46,302				46,302
Production taxes	13,127				13,127
General and administrative	6,995	892	266		8,153
Oil and gas marketing expenses		225,999		(158,311)	67,688
Oil and gas depreciation, depletion and amortization	99,397				99,397
Other depreciation and amortization	4,655	770	1,337		6,762
Total Operating Costs	170,476	227,661	1,603	(158,311)	241,429
INCOME (LOSS) FROM OPERATIONS	43,085	768	(1,603)		42,250
OTHER INCOME (EXPENSE):					
Interest and other income	1,152	211	58,681	(54,507)	5,537
Interest expense	(52,630)	(8)	(53,049)	54,507	(51,180)
Loss on repurchases of Chesapeake debt			(864)		(864)
Equity in net earnings of subsidiaries			(4,452)	4,452	
Total Other Income (Expense)	(51,478)	203	316	4,452	(46,507)
INCOME (LOSS) BEFORE INCOME TAXES	(8,393)	971	(1,287)	4,452	(4,257)
Income tax expense (benefit)	(3,358)	388	1,266		(1,704)
NET INCOME (LOSS)	$ (5,035)	$ 583	$ (2,553)	$ 4,452	$ (2,553)

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CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2003:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 490,841	$ (119,599)	$ 164,021	$ (158,630)	$ 376,633
CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(343,997)		(929,598)		(1,273,595)
Investment in Pioneer Drilling Company			(20,000)		(20,000)
Other	(6,062)	(4,260)	(11,857)		(22,179)
Cash (used in) provided by investing activities	(350,059)	(4,260)	(961,455)		(1,315,774)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	296,000				296,000
Payments on long-term borrowings	(270,000)				(270,000)
Net increase in outstanding payments in excess of cash balances	29,474				29,474
Cash received from issuance of senior notes			297,306		297,306
Cash paid for issuance costs of senior notes			(6,367)		(6,367)
Cash paid for treasury stocks			(2,109)		(2,109)
Proceeds from issuance of common stock, net of issuance costs			177,444		177,444
Proceeds from issuance of preferred stock, net of issuance costs			222,893		222,893
Cash dividends paid on preferred stock and common stock			(21,018)		(21,018)
Exercise of stock options and warrants			6,326		6,326
Other	(2,314)		(222)		(2,536)
Intercompany advances, net	(162,460)	135,772	(131,942)	158,630	
Cash provided by (used in) financing activities	(109,300)	135,772	542,311	158,630	727,413
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	31,482	11,913	(255,123)		(211,728)
CASH, BEGINNING OF PERIOD	(31,975)	24,448	255,164		247,637
CASH, END OF PERIOD	$ (493)	$ 36,361	$ 41	$	$ 35,909

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2002:					
CASH FLOWS FROM OPERATING ACTIVITIES	$ 213,415	$ (13,657)	$ 10,615	$ 4,452	$ 214,825

CASH FLOWS FROM INVESTING ACTIVITIES:					
Oil and gas properties, net	(180,545)		(127,251)		(307,796)
Additions to other property, plant and equipment and other	(6,499)	(3,408)	(8,676)		(18,583)
Other investments, net			1,807		1,807
Cash (used in) provided by investing activities	(187,044)	(3,408)	(134,120)		(324,572)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from long-term borrowings	45,000				45,000
Cash paid for issuance costs of senior notes			(95)		(95)
Cash paid for repurchase of senior notes			(42,201)		(42,201)
Cash paid for repurchase premium on senior notes			(1,019)		(1,019)
Cash dividends paid on preferred stock			(5,118)		(5,118)
Exercise of stock options			1,956		1,956
Other			(74)		(74)
Intercompany advances, net	(59,807)	3,394	60,865	(4,452)	
Cash (used in) provided by financing activities	(14,807)	3,394	14,314	(4,452)	(1,551)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	11,564	(13,671)	(109,191)		(111,298)
CASH, BEGINNING OF PERIOD	(11,313)	19,714	109,193		117,594
CASH, END OF PERIOD	$ 251	$ 6,043	$ 2	$	$ 6,296

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CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

($ in thousands)

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2003:					
Net income (loss)	$ 81,358	$ 1,584	$ 82,240	$ (82,942)	$ 82,240
Other comprehensive income (loss) net of income tax:					
Change in fair value of derivative instruments	11,696				11,696
Reclassification of loss on settled contracts	2,461				2,461
Ineffectiveness portion of derivatives qualifying for cash flow hedge accounting	(256)				(256)
Equity in net other comprehensive income (loss) of subsidiaries			13,901	(13,901)	
Comprehensive income (loss)	$ 95,259	$ 1,584	$ 96,141	$ (96,843)	$ 96,141

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Three Months Ended June 30, 2002:					
Net income	$ 22,205	$ 465	$ 25,033	$ (22,670)	$ 25,033
Other comprehensive income (loss), net of income tax:					
Change in fair value of derivative instruments	(2,242)				(2,242)
Reclassification of gain on settled contracts	(1,683)				(1,683)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	815				815
Equity in net other comprehensive income (loss) of subsidiaries			(3,110)	3,110	
Comprehensive income (loss)	$ 19,095	$ 465	$ 21,923	$ (19,560)	$ 21,923

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2003:					
Net income (loss)	$ 157,086	$ 1,544	$ 155,749	$ (158,630)	$ 155,749
Other comprehensive income (loss) net of income tax:					
Change in fair value of derivative instruments	(36,859)				(36,859)
Reclassification of loss on settled contracts	53,352				53,352
Ineffectiveness portion of derivatives qualifying for cash flow hedge accounting	(286)				(286)
Equity in net other comprehensive income (loss) of subsidiaries			16,207	(16,207)	

Comprehensive income (loss)	$ 173,293	$ 1,544	$ 171,956	$ (174,837)	$ 171,956

	Guarantor Subsidiaries	Non-Guarantor Subsidiary	Parent	Eliminations	Consolidated
For the Six Months Ended June 30, 2002:					
Net income (loss)	$ (5,035)	$ 583	$ (2,553)	$ 4,452	$ (2,553)
Other comprehensive income (loss), net of income tax:					
Change in fair value of derivative instruments	(12,972)				(12,972)
Reclassification of gain on settled contracts	(15,769)				(15,769)
Ineffective portion of derivatives qualifying for cash flow hedge accounting	1,309				1,309
Equity in net other comprehensive income (loss) of subsidiaries			(27,432)	27,432	
Comprehensive income (loss)	$ (32,467)	$ 583	$ (29,985)	$ 31,884	$ (29,985)

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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. Recent Accounting Pronouncements

During 2002 and 2003, the Financial Accounting Standards Board issued the following Statements of Financial Accounting Standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In July 2002, the FASB issued SFAS No. 146, *Accounting For Costs Associated with Exit or Disposal Activities*. SFAS 146 is effective for exit or disposal activities initiated after December 31, 2002. We adopted this standard during the quarter ended March 31, 2003 and it did not have any impact on our financial position or results of operations.

In March 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. SFAS 149 is effective for contracts entered into or modified after June 30, 2003. This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. We do not expect the adoption of this standard to have any significant impact on our financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity.* SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003 and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. This statement establishes new standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. SFAS 150 requires that an issuer classify a financial instrument that is within the scope of this statement as a liability because the financial instrument embodies an obligation of the issuer. This statement applies to certain forms of mandatorily redeemable financial instruments including certain types of preferred stock, written put options and forward contracts. We do not expect the adoption of this standard to have a significant impact on our financial position or results of operations.

8. Asset Retirement Obligations

Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting for Asset Retirement Obligations.* This statement applies to obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction and development of the assets.

SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold, at which time the liability is reversed and any gain or loss resulting from the settlement of the obligation is recorded.

We identified and estimated all of our asset retirement obligations for tangible, long-lived assets as of January 1, 2003. These obligations were for plugging and abandonment costs for depleted oil and gas wells. Prior to the adoption of SFAS 143, we included an estimate of our asset retirement obligations related to our oil and gas properties in our calculation of oil and gas depreciation, depletion and amortization expense. Upon adoption of SFAS 143, we recorded the discounted fair value of our expected future obligations. During the quarter ended March 31, 2003, we recorded a $30.5 million liability, a cumulative effect for the change in accounting principle as an increase to earnings of $2.4 million (net of income taxes) and an increase in net oil and gas properties of $34.3 million. The pro-forma effect on prior periods financial position and results of operations was not material.

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The components of the change in our asset retirement obligations are shown below.

	Three Months Ended June 30, 2003	Six Months Ended June 30, 2003
Asset retirement obligations, beginning balance	$ 46,438	$ 30,479
Additions and revisions	1,246	16,543
Settlements and disposals	(3,771)	(3,771)
Accretion expense	786	1,448
Asset retirement obligations, ending balance	$ 44,699	$ 44,699

9. Acquisitions and Related Financing

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of ONEOK, Inc. in January 2003 for $296 million, $15 million of which was paid in 2002. In March 2003, we acquired El Paso Corporation s Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million and Vintage Petroleum, Inc. s assets in the Bray Field in southern Oklahoma for $29 million. We also completed an acquisition of privately-owned Oxley Petroleum Company for $155 million on May 31, 2003.

In March 2003, Chesapeake bought 5.3 million newly issued common shares of Pioneer Drilling Company, or 24.6% of its outstanding common shares, at $3.75 per share, for a total investment of $20 million.

On March 5, 2003, we issued 23 million shares of common stock pursuant to a shelf registration statement for net proceeds of $177.4 million. We also issued 4.6 million shares of 6.00% cumulative convertible preferred stock with a liquidation value of $230 million. The net proceeds from the preferred stock were $222.9 million. These proceeds, along with the net proceeds of $290.9 million from the issuance of the $300 million in aggregate principal amount of 7.50% senior notes issued at the same time, were used to fund acquisitions completed in March 2003 and to repay credit facility indebtedness. Each share of the 6.00% preferred stock is convertible at any time at the option of the holder into 4.8605 shares of our common stock, subject to adjustment. At June 30, 2003, 41.8 million shares of our common stock were reserved for issuance upon conversion of the 6.00% and 6.75% cumulative convertible preferred stock.

10. Subsequent Events

On July 16, 2003, we issued an additional $29.5 million of our 7.75% senior notes due 2015 in exchange for $27.9 million of our 8.375% senior notes due 2008 and $0.5 million of accrued interest, pursuant to a privately negotiated transaction. The $27.9 million of 8.375% senior notes due 2008 were retired upon receipt.

On July 31, 2003, Chesapeake purchased oil and gas properties, a gathering system and a gas treatment plant from a major oil and gas company for $44.5 million.

On August 5, 2003, we issued an additional $33.5 million of our 7.75% senior notes due 2015 in exchange for $32.0 million of our 8.5% senior notes due 2012 and $1.1 million of accrued interest, pursuant to a privately negotiated transaction. The $32.0 million of 8.5% senior notes were retired upon receipt.

On August 13, 2003, we entered into an interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
August 2003 August 2005	$100,000,000	2.735%	U.S. six-month LIBOR in arrears

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 this interest rate swap will be made on February 15 and August 15 of each year beginning February 15, 2004.

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11. Income Statement Reclassifications

We have reclassified certain amounts in our previously reported condensed consolidated financial statements for the three and six months ended June 30, 2003 and 2002. These reclassifications had no effect on previously reported net income or net income per share.

For the three and six months ended June 30, 2003 and 2002, Chesapeake has reclassified unrealized gains and losses on certain derivative instruments. Previously, gains (losses) resulting from ineffectiveness of oil and gas derivative contracts designated as cash flow hedges, as well as the net unrealized gains and losses related to oil and gas derivative contracts not qualifying for hedge accounting under SFAS 133, were separately classified as risk management income (loss) . These amounts have been reclassified and are now included in oil and gas sales for the three and six months ended June 30, 2003 and 2002. For the three and six months ended June 30, 2003 and 2002 we have also reclassified to interest expense ineffectiveness related to the fair value of derivatives designated as hedges, as well as the amortization of realized gains and losses on interest rate derivative instruments that were previously reported as risk management income (loss).

The effects of these reclassifications on the condensed consolidated statements of operations previously reported for the three and six months ended June 30, 2003 and 2002 are presented below.

	Three Months Ended June 30,			
	2003		2002	
	As Previously Reported	As Revised	As Previously Reported	As Revised
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 316,172	$ 319,519	$ 152,009	$ 150,905
Risk management income (loss)	3,084		(481)	
Oil and gas marketing sales	110,296	110,296	42,785	42,785
Total Revenues	429,552	429,815	194,313	193,690
OPERATING COSTS	259,913	259,913	131,623	131,623
INCOME FROM OPERATIONS	169,639	169,902	62,690	62,067
OTHER INCOME (EXPENSE):				
Interest and other income	781	781	3,992	3,992
Interest expense	(37,773)	(38,036)	(24,690)	(24,067)
Loss on repurchases of Chesapeake debt			(273)	(273)
Total Other Income (Expense)	(36,992)	(37,255)	(20,971)	(20,348)
INCOME (LOSS) BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	132,647	132,647	41,719	41,719
INCOME TAX EXPENSE (BENEFIT):				

Current				
Deferred	50,407	50,407	16,686	16,686
Total Income Tax Expense (Benefit)	50,407	50,407	16,686	16,686
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	82,240	82,240	25,033	25,033
Cumulative effect of accounting change, net of income taxes of $1,464,000				
NET INCOME (LOSS)	82,240	82,240	25,033	25,033
Preferred stock dividends	(5,979)	(5,979)	(2,530)	(2,530)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 76,261	$ 76,261	$ 22,503	$ 22,503
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.36	$ 0.36	$ 0.14	$ 0.14
Assuming dilution	$ 0.31	$ 0.31	$ 0.13	$ 0.13

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	Six Months Ended June 30,			
	2003		2002	
	As Previously Reported	As Revised	As Previously Reported	As Revised
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 572,504	$ 605,538	$ 293,980	$ 213,561
Risk management income (loss)	30,794		(79,949)	
Oil and gas marketing sales	200,604	200,604	70,118	70,118
Total Revenues	803,902	806,142	284,149	283,679
OPERATING COSTS	485,288	485,288	241,429	241,429
INCOME FROM OPERATIONS	318,614	320,854	42,720	42,250
OTHER INCOME (EXPENSE):				
Interest and other income	1,544	1,544	5,537	5,537
Interest expense	(72,800)	(75,040)	(51,650)	(51,180)
Loss on repurchases of Chesapeake debt			(864)	(864)
Total Other Income (Expense)	(71,256)	(73,496)	(46,977)	(46,507)
INCOME (LOSS) BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	247,358	247,358	(4,257)	(4,257)
INCOME TAX EXPENSE (BENEFIT):				
Current				
Deferred	93,998	93,998	(1,704)	(1,704)
Total Income Tax Expense (Benefit)	93,998	93,998	(1,704)	(1,704)
NET INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	153,360	153,360	(2,553)	(2,553)
Cumulative effect of accounting change, net of income taxes of $1,464,000	2,389	2,389		
NET INCOME (LOSS)	155,749	155,749	(2,553)	(2,553)
Preferred stock dividends	(9,505)	(9,505)	(5,062)	(5,062)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$ 146,244	$ 146,244	$ (7,615)	$ (7,615)
EARNINGS (LOSS) PER COMMON SHARE BASIC:				
Income (loss) before cumulative effect of accounting change	$ 0.70	$ 0.70	$ (0.05)	$ (0.05)
Cumulative effect of accounting change	0.01	0.01		
Net income (loss)	$ 0.71	$ 0.71	$ (0.05)	$ (0.05)
EARNINGS (LOSS) PER COMMON SHARE ASSUMING DILUTION:				
Income (loss) before cumulative effect of accounting change	$ 0.62	$ 0.62	$ (0.05)	$ (0.05)
Cumulative effect of accounting change	0.01	0.01		

Net income (loss)	$ 0.63	$ 0.63	$ (0.05)	$ (0.05)

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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:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2003	**2002**	**2003**	**2002**
Net Production:				
Oil (mbbl)	1,224	823	2,284	1,653
Gas (mmcf)	59,990	38,464	110,382	75,397
Gas equivalent (mmcfe)	67,334	43,402	124,086	85,315
Oil and Gas Sales ($ in thousands):				
Oil sales	$ 32,763	$ 21,155	$ 67,903	$ 38,715
Oil derivatives realized gains (losses)	(641)	696	(6,879)	3,094
Oil derivatives unrealized gains (losses)	(1,101)	549	(1,178)	(6,816)
Total oil sales	31,021	22,400	59,846	34,993
Gas sales	$ 282,239	$ 117,419	$ 596,289	$ 193,276
Gas derivatives realized gains (losses)	1,811	12,739	(84,809)	58,895
Gas derivatives unrealized gains (losses)	4,448	(1,653)	34,212	(73,603)
Total gas sales	288,498	128,505	545,692	178,568
Total oil and gas sales	$ 319,519	$ 150,905	$ 605,538	$ 213,561
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$ 26.77	$ 25.70	$ 29.73	$ 23.42
Gas ($ per mcf)	$ 4.70	$ 3.05	$ 5.40	$ 2.56
Gas equivalent ($ per mcfe)	$ 4.68	$ 3.19	$ 5.35	$ 2.72
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 26.24	$ 26.55	$ 26.72	$ 25.29
Gas ($ per mcf)	$ 4.73	$ 3.38	$ 4.63	$ 3.34
Gas equivalent ($ per mcfe)	$ 4.70	$ 3.50	$ 4.61	$ 3.45
Expenses ($ per mcfe):				
Production expenses	$ 0.51	$ 0.56	$ 0.53	$ 0.54
Production taxes	$ 0.25	$ 0.18	$ 0.29	$ 0.15
General and administrative	$ 0.09	$ 0.09	$ 0.09	$ 0.10
Depreciation, depletion and amortization	$ 1.36	$ 1.17	$ 1.36	$ 1.17
Net Wells Drilled	102	67	196	124

Net Producing Wells at End of Period	5,591	3,862	5,591	3,862

Significant Developments During Current Period

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of ONEOK, Inc. in January 2003. We paid $296 million in cash for these assets, $15 million of which was paid in late 2002.

On March 5, 2003, we issued 23 million shares of common stock pursuant to a shelf registration statement for net proceeds of $177.4 million. We also issued 4.6 million shares of 6.00% cumulative convertible preferred stock with a liquidation value of $230 million. The net proceeds were $222.9 million.

Also in March 2003, we closed a private offering of $300 million in aggregate principal amount of 7.50% senior notes due 2013. The net proceeds were $290.9 million. These proceeds, along with the net proceeds from the common stock and preferred stock offerings, were used to fund acquisitions completed in March 2003 and to repay credit facility indebtedness.

In March 2003, we acquired El Paso Corporation s Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million.

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In March 2003, we acquired Vintage Petroleum Inc. s assets in the Bray Field of southern Oklahoma for $29 million.

On May 31, 2003, we acquired privately-owned Oxley Petroleum Company for $155 million. The acquired assets are primarily in the Arkoma Basin, which is located in eastern Oklahoma and western Arkansas.

Results of Operations Three Months Ended June 30, 2003 (Current Quarter) vs. June 30, 2002 (Prior Quarter)

General. For the Current Quarter, Chesapeake had net income of $76.3 million, or $0.31 per diluted common share, on total revenues of $429.8 million. This compares to net income of $22.5 million, or $0.13 per diluted common share, on total revenues of $193.7 million during the Prior Quarter. The Current Quarter net income includes, on a pre-tax basis, $3.1 million in net unrealized gains on oil and gas and interest rate derivatives. The Prior Quarter net income included, on a pre-tax basis, $0.5 million in net unrealized losses on oil and gas and interest rate derivatives that have not been designated as hedges in accordance with SFAS 133.

Oil and Gas Sales. During the Current Quarter, oil and gas sales were $319.5 million versus $150.9 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 67.3 bcfe at a weighted-average price of $4.70 per mcfe, compared to 43.4 bcfe produced in the Prior Quarter at a weighted-average price of $3.50 per mcfe (weighted-average prices for all periods presented exclude unrealized gains (losses) on derivatives). The increase in realized prices in the Current Quarter resulted in an increase in oil and gas sales of $80.8 million along with an increase of $83.4 million due to increased production, for a net increase in realized oil and gas sales (excluding unrealized gains or losses on oil and gas derivatives) of $164.2 million.

Changes in oil and gas prices have a significant impact on our oil and gas revenues and cash flows. Based upon the Current Quarter production levels, a change of $0.10 per mcf of natural gas would result in a quarterly increase/decrease in revenues and cash flow of approximately $6.0 million and $5.7 million, respectively, without considering the effect of derivatives and a change of $1.00 per barrel of oil would result in a quarterly increase/decrease in revenues and cash flows of approximately $1.2 million each without considering the effect of derivatives.

For the Current Quarter, we realized an average price per barrel of oil of $26.24, compared to $26.55 in the Prior Quarter. Natural gas prices realized per mcf were $4.73 and $3.38 in the Current Quarter and Prior Quarter, respectively (all weighted-average prices presented exclude unrealized gains (losses) on derivatives). Realized gains from derivatives increased oil and gas revenues from $315.0 million to $316.2 million, an increase of $1.2 million, or $0.02 per mcfe, in the Current Quarter compared to an increase from $138.6 million to $152.0 million, an increase of $13.4 million, or $0.31 per mcfe, in the Prior Quarter.

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

	For the Three Months Ended June 30,			
	2003		2002	
Operating Areas	**Mmcfe**	**Percent**	**Mmcfe**	**Percent**

Mid-Continent	59,210	88%	35,171	81%
Gulf Coast	5,249	8	5,725	13
Permian Basin	2,143	3	1,747	4
Williston Basin and Other	732	1	759	2
Total Production	67,334	100%	43,402	100%

Natural gas production represented approximately 89% of our total production volume on an equivalent basis in the Current Quarter and the Prior Quarter.

Oil and Gas Marketing Sales. Chesapeake realized $110.3 million in oil and gas marketing sales for third parties in the Current Quarter, with corresponding oil and gas marketing expenses of $106.9 million, for a net margin of $3.4 million. This compares to sales of $42.8 million and expenses of $41.2 million, for a net margin of $1.6 million in the Prior Quarter. The increased activity in the Current Quarter is primarily the result of higher prices received in the Current Quarter combined with an increase in volumes resulting from acquisitions that occurred in late 2002 and the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $34.3 million in the Current Quarter, a $10.1 million increase from the $24.2 million of production expenses incurred in the Prior Quarter. On a unit of production basis, production expenses were $0.51 and $0.56 per mcfe in the Current

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and Prior Quarters, respectively. The decrease in costs on a per unit basis in 2003 compared to 2002 is due primarily to lower operating costs associated with acquisitions completed in 2003. We expect that production expenses per mcfe produced for the remainder of 2003 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $17.1 million and $7.9 million in the Current and Prior Quarters, respectively. On a unit of production basis, production taxes were $0.25 per mcfe in the Current Quarter compared to $0.18 per mcfe in the Prior Quarter. The increase in the Current Quarter of $9.2 million was due to an increase in production volumes of 55% as well as an increase in the average wellhead prices received for natural gas. 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 2003 will range from $0.31 to $0.33 per mcfe based on our assumption that oil and natural gas wellhead prices will range from $4.50 to $5.00 per mcfe produced.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties, were $6.0 million in the Current Quarter compared to $3.9 million in the Prior Quarter. The increase in the Current Quarter is the result of the company s growth related to acquisitions completed during the Current Period and in 2002. On a per unit of production basis, general and administrative expenses were $0.09 in both the Current and Prior Quarters. We expect general and administrative expenses for the remainder of 2003 to be between $0.09 and $0.10 per mcfe produced.

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 $8.5 million and $5.9 million of internal costs in the Current Quarter and Prior Quarter, respectively, directly related to our oil and gas exploration and development efforts.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Quarter was $91.6 million, compared to $50.8 million in the Prior Quarter. The average DD&A rate per mcfe, which is a function of capitalized costs, estimated salvage value, future development costs and the related underlying reserves in the periods presented, increased from $1.17 in the Prior Quarter to $1.36 in the Current Quarter. The increase in the average rate in the Current Quarter is primarily the result of higher drilling costs and higher costs associated with acquisitions. We expect the DD&A rate for the remainder of 2003 to be between $1.35 and $1.40 per mcfe produced.

Effective January 1, 2003, Chesapeake adopted SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold. This accretion expense is included in DD&A expense on oil and gas properties. In addition, SFAS 143 effectively reduces DD&A rates when compared to prior periods (prior to accretion expense) by including the capitalized retirement obligation at its discounted fair value rather than the undiscounted amount of the estimated liability. During the Current Quarter, accretion expense related to asset retirement obligations was $0.8 million and is included in oil and gas depreciation, depletion and amortization expense.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $4.1 million in the Current Quarter, compared to $3.7 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation costs on recently acquired fixed assets. Other property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 31.5 years, drilling rigs are depreciated over 12 years and all other property and equipment is depreciated over the estimated useful lives of the assets which range from three to seven years. To the extent the drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect depreciation and amortization of other assets to be between $0.08 and

$0.10 per mcfe produced for the remainder of 2003.

Interest and Other Income. Interest and other income was $0.8 million in the Current Quarter compared to $4.0 million in the Prior Quarter. The decrease in the Current Quarter was the result of a decrease in interest income on outstanding cash balances during the Current Quarter and the recognition of interest income in the Prior Quarter related to our investment in notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $38.0 million in the Current Quarter from $24.1 million in the Prior Quarter. The increase in the Current Quarter is due to a $670.1 million increase in average long-term borrowings in the Current Quarter compared to the Prior Quarter. In addition to the interest expense reported, we capitalized $3.5 million of interest during the Current Quarter, compared to $1.1 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 on our outstanding borrowings. We expect interest expense for the remainder of 2003 to be between $0.60 and $0.65 per mcfe produced based on indebtedness as of June 30, 2003.

From time to time, we enter into derivative instruments designed to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value of interest rate derivatives are recorded on the condensed consolidated balance sheets as assets (liabilities) and the debt s carrying amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense. Interest expense during the Current Quarter included a realized gain on the settlement of an interest rate swap of $0.2 million and a gain on swaption ineffectiveness of $0.3 million. Interest expense during the Prior Quarter included an unrealized gain on an interest rate swap of $3.3 million and a loss on swaption ineffectiveness of $1.1 million.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $50.4 million in the Current Quarter, compared to income tax expense of $16.7 million in the Prior Quarter. We anticipate that the effective tax rate for 2003 will be approximately 38% and all 2003 income tax expense will be deferred.

Results of Operations Six Months Ended June 30, 2003 (Current Period) vs. June 30, 2002 (Prior Period)

General. For the Current Period, Chesapeake had net income of $146.2 million, or $0.63 per diluted common share, on total revenues of $806.1 million. This compares to a net loss of $7.6 million, or a loss of $0.05 per diluted common share, on total revenues of $283.7 million during the Prior Period. The Current Period net income includes, on a pre-tax basis, $30.8 million in net unrealized gains on certain of its oil and gas and interest rate derivatives . The Prior Period net loss included, on a pre-tax basis, $79.9 million in net unrealized losses on certain of its oil and gas and interest rate derivatives.

Oil and Gas Sales. During the Current Period, oil and gas sales were $605.5 million versus $213.6 million in the Prior Period. In the Current Period Chesapeake produced 124.1 bcfe at a weighted-average price of $4.61 per mcfe, compared to 85.3 bcfe produced in the Prior Period at a weighted-average price of $3.45 per mcfe (weighted-average prices for all periods presented exclude unrealized gains (losses) on derivatives). The increase in prices in the Current Period resulted in an increase in oil and gas sales of $143.9 million along with an increase of $134.6 million due to increased production, for a net increase in oil and gas sales (excluding unrealized gains (losses) on oil and gas derivatives) of $278.5 million. Unrealized gains (losses) included in oil and gas sales in the Current Period and Prior Period were $33.0 million and ($80.4) million, respectively.

Changes in oil and gas prices have a significant impact on our oil and gas revenues and cash flows. Based upon the Current Period production levels, a change of $0.10 per mcf of natural gas would result in an increase/decrease in revenues and cash flow of approximately $11.0 million and $10.3 million, respectively, without considering the effect of derivatives, and a change of $1.00 per barrel of oil would result in an increase/decrease in revenues and cash flows of approximately $2.3 million and $2.1 million, respectively, without considering the effect of derivatives.

For the Current Period, we realized an average price per barrel of oil of $26.72, compared to $25.29 in the Prior Period. Natural gas prices realized per mcf were $4.63 and $3.34 in the Current Period and Prior Period, respectively (all weighted-average prices presented exclude unrealized gains (losses) on derivatives). Realized gains or losses from derivatives decreased oil and gas revenues from $664.2 million to $572.5 million, a decrease of $91.7 million, or $0.74 per mcfe, in the Current Period compared to an increase from $232.0 million to $294.0 million, an increase of $62.0 million, or $0.73 per mcfe, in the Prior Period.

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

	For the Six Months Ended June 30,			
	2003		2002	
Operating Areas	**Mmcfe**	**Percent**	**Mmcfe**	**Percent**
Mid-Continent	107,989	87%	66,972	79%
Gulf Coast	10,597	9	12,985	15
Permian Basin	3,994	3	3,804	4
Williston Basin and Other	1,506	1	1,554	2
Total Production	124,086	100%	85,315	100%

Natural gas production represented approximately 89% of our total production volume on an equivalent basis in the Current Period, compared to 88% in the Prior Period.

Oil and Gas Marketing Sales. Chesapeake realized $200.6 million in oil and gas marketing sales for third parties in the Current Period, with corresponding oil and gas marketing expenses of $196.2 million, for a net margin of $4.4 million. This compares to sales of $70.1 million and expenses of $67.7 million, for a net margin of $2.4 million in the Prior Period. The increased activity in the Current Period is primarily the result of higher prices received in the Current Period combined with an increase in volumes resulting from acquisitions that occurred in late 2002 and the Current Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $65.7 million in the Current Period, a $19.4 million increase from the $46.3 million of production expenses incurred in the Prior Period. On a unit of production basis, production expenses were $0.53 and $0.54 per mcfe in the Current and Prior Periods, respectively. The decrease in costs on a per unit basis in 2003 compared to 2002 is due primarily to lower operating costs associated with acquisitions completed in 2003. We expect that production expenses per mcfe produced for the remainder of 2003 will range from $0.53 to $0.57.

Production Taxes. Production taxes were $35.7 million and $13.1 million in the Current and Prior Periods, respectively. On a unit of production basis, production taxes were $0.29 per mcfe in the Current Period compared to $0.15 per mcfe in the Prior Period. The increase in the Current Period of $22.6 million was due to an increase in production volumes of 45% as well as an increase in the average wellhead prices received for natural gas. 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 2003 will range from $0.31 to $0.33 per mcfe based on our assumption that oil and natural gas wellhead prices will range from $4.50 to $5.00 per mcfe produced.

General and Administrative Expense. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties, were $11.7 million in the Current Period compared to $8.2 million in the Prior Period. The increase in the Current Period is the result of the company s growth related to acquisitions completed during the Current Period and in 2002. On a per unit of production basis, general and administrative expenses were $0.09 and 0.10 in the Current and Prior Periods, respectively. We expect general and administrative expenses for the remainder of 2003 to be between $0.09 and $0.10 per mcfe produced.

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 $15.8 million and $11.6 million of internal costs in the Current Period and Prior Period, respectively, directly related to our oil and gas exploration and development efforts.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties for the Current Period was $168.2 million, compared to $99.4 million in the Prior Period. The average DD&A rate per mcfe, which is a function of capitalized costs, estimated salvage value, future development costs and the related underlying reserves in the periods presented, increased from $1.17 in the Prior Period to $1.36 in the Current Period. The increase in the average rate in the Current Period is primarily the result of higher drilling costs and higher costs associated with acquisitions. We expect the DD&A rate for the remainder of 2003 to be between $1.35 and $1.40 per mcfe produced.

Effective January 1, 2003, Chesapeake adopted SFAS 143, *Accounting for Asset Retirement Obligations.* SFAS 143 requires that the fair value of a liability for a retirement obligation be recognized in the period in which the liability is incurred. For oil and gas properties, this is the period in which an oil or gas well is acquired or drilled. The asset retirement obligation is capitalized as part of the carrying amount of our oil and gas properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the well is sold.

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This accretion expense is included in DD&A expense on oil and gas properties. In addition, SFAS 143 effectively reduces DD&A rates when compared to prior periods (prior to accretion expense) by including the capitalized retirement obligation at its discounted fair value rather than the undiscounted amount of the estimated liability. During the Current Period, accretion expense related to asset retirement obligations was $1.4 million and is included in oil and gas depreciation, depletion and amortization expense.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $7.8 million in the Current Period, compared to $6.8 million in the Prior Period. The increase in the Current Period was primarily the result of higher depreciation costs on recently acquired fixed assets. Other property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 31.5 years, drilling rigs are depreciated over 12 years and all other property and equipment is depreciated over the estimated useful lives of the assets which range from three to seven years. To the extent the drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and gas properties as exploration or development costs. We expect depreciation and amortization of other assets to be between $0.08 and $0.10 per mcfe produced for the remainder of 2003.

Interest and Other Income. Interest and other income was $1.5 million in the Current Period compared to $5.5 million in the Prior Period. The decrease in the Current Period was the result of a decrease in interest income on outstanding cash balances during the Current Period and the recognition of interest income in the Prior Period related to our investment in notes issued by Seven Seas Petroleum Inc.

Interest Expense. Interest expense increased to $75.0 million in the Current Period from $51.2 million in the Prior Period. The increase in the Current Period is due to a $529.5 million increase in average long-term borrowings in the Current Period compared to the Prior Period. In addition to the interest expense reported, we capitalized $5.4 million of interest during the Current Period, compared to $2.3 million capitalized in the Prior Period, 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 on our outstanding borrowings. We expect interest expense for the remainder of 2003 to be between $0.60 and $0.65 per mcfe produced based on indebtedness as of June 30, 2003.

From time to time, we enter into derivative instruments designed to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value of interest rate derivatives are recorded on the condensed consolidated balance sheets as assets (liabilities) and the debt s carrying amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense. Interest expense during the Current Period included a realized gain on the settlement of the interest rate swap of $0.3 million and a loss on swaption ineffectiveness of $1.2 million. Interest expense during the Prior Period included an unrealized gain on the interest rate swap of $3.2 million and a loss on swaption ineffectiveness of $1.1 million.

Provision (Benefit) for Income Taxes. Chesapeake recorded income tax expense of $94.0 million in the Current Period, compared to income tax benefit of $1.7 million in the Prior Period. We anticipate that the effective tax rate for 2003 will be approximately 38% and all 2003 income tax expense will be deferred.

Cash Flows From Operating, Investing and Financing Activities

Cash Flows from Operating Activities. Cash provided by operating activities increased 75% to $376.6 million during the Current Period compared to $214.8 million during the Prior Period. The increase was due primarily to an increase in revenue in the Current Period partially offset by reductions to working capital.

Cash Flows from Investing Activities. Cash used in investing activities increased to $1,315.8 million during the Current Period from $324.6 million in the Prior Period. During the Current Period, we expended approximately $307.1 million to drill 455 (196 net) wells and invested approximately $123.1 million in unproved properties. This compares to $176.4 million to initiate drilling on 281 (124 net) wells and $7.2 million to purchase unproved properties in the Prior Period. During the Current Period, we completed acquisitions of proved oil and gas properties of $863.1 million and completed $19.7 million of divestitures of proved oil and gas properties. This compares to cash used in acquisitions of proved oil and gas properties of $124.3 million and no divestitures in the Prior Period. During the Current Period, we had additional investments in drilling rig equipment and other fixed assets of $22.2 million compared to $16.7 million in the Prior Period. The Current Period included an investment of $20.0 million in the common stock of Pioneer Drilling Company (AMEX: PDC).

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Cash Flows from Financing Activities. Financing activities provided $727.4 million of cash in the Current Period, compared to $1.6 million of cash used in financing activities in the Prior Period. During the Current Period, we borrowed $296.0 million under our bank credit facility and made repayments under this facility of $270.0 million. In the Current Period, we received $297.3 million from the issuance of $300 million principal amount of our 7.50% senior notes and paid $6.4 million in costs related to the issuance of these notes. We issued 23 million shares of common stock and received $177.4 million of net proceeds. We issued 4.6 million shares of 6.00% cumulative convertible preferred stock, $50 per share liquidation preference, or $230 million in the aggregate, and received $222.9 million of net proceeds. During the Current Period, we used $12.1 million to pay common stock dividends, $5.1 million to pay dividends on our 6.75% preferred stock, $3.8 million to pay dividends on our 6.00% preferred stock and $2.1 million to purchase treasury stock. We received $6.3 million from the exercise of stock options and warrants, and we had $29.5 million of outstanding payments in excess of our funded cash balances as of June 30, 2003. The activity in the Prior Period included borrowings under our bank credit facility of $45.0 million, which was primarily offset by the repurchase of $43.2 million of our 7.875% senior notes. We received $2.0 million in cash received from the exercise of stock options and used $5.1 million for the payment of dividends on our 6.75% preferred stock.

Liquidity and Capital Resources

Sources of Liquidity

Chesapeake had a working capital deficit of $82.4 million at June 30, 2003, including $35.9 million in cash. Another source of liquidity is our $350 million revolving bank credit facility (see discussion below).

We believe we will have adequate resources, including budgeted cash flows from operating activities before changes in assets and liabilities, working capital and proceeds from our revolving bank credit facility, to fund our exploration and development activities during the remainder of 2003. Our capital expenditure budget for drilling, land and seismic data for 2003 is estimated to be between $600 million and $650 million. However, higher drilling and field operating costs, unfavorable drilling results or other factors could cause us to reduce our drilling program, which is largely discretionary. Any operating cash flow not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes in 2003.

A significant portion of our liquidity at June 30, 2003 is concentrated in cash and accounts receivable. Financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in debt instruments, equity securities and accounts receivable. 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

We have a $350 million revolving bank credit facility (with a committed borrowing base of $350 million) which matures in May 2007. As of June 30, 2003, we had $26.0 million of outstanding borrowings under this facility and utilized $25.3 million of the facility for 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 our senior unsecured long-term debt ratings issued by Standard & Poor s Ratings Services and Moody s Investor Service. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee also based on our senior unsecured long-term debt ratings. Interest is payable quarterly.

The credit agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, sell properties, pay dividends, purchase or redeem our capital stock, make investments or loans or purchase certain of our senior notes, and create liens. The credit agreement requires us to maintain a current

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ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio for the trailing twelve month period (as defined) of at least 2.5 to 1. At June 30, 2003, our current ratio was 1.6 to 1 and our fixed charge coverage ratio was 3.6 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 $10.0 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 agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $25.0 million.

As of June 30, 2003, senior notes represented approximately $2.0 billion of our long-term debt and consisted of the following ($ in thousands):

7.875% senior notes, due 2004	$ 42,137(1)
8.375% senior notes, due 2008	250,000
8.125% senior notes, due 2011	800,000
9.000% senior notes, due 2012	300,000
8.500% senior notes, due 2012	142,665
7.500% senior notes, due 2013	300,000
7.750% senior notes, due 2015	150,000
	$ 1,984,802

(1) This amount has been classified as long-term debt based on our ability to satisfy this obligation with funding from our bank credit facility.

There are no scheduled principal payments required on any of the senior notes until March 2004, when $42.1 million is due. Debt ratings for the senior notes are Ba3 by Moody s Investor Service, BB- by Standard & Poor s Ratings Services and BB- by Fitch Ratings as of July 10, 2003. Debt ratings for our secured bank credit facility are Ba2 by Moody s Investor Service, BBB- 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 indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures for the 8.125%, 8.375%, 9.000%, 7.750% and 7.500% 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 June 30, 2003, we estimate that secured commercial bank indebtedness of approximately $869 million could have been incurred under the most restrictive indenture covenant. The indenture covenants do not apply to Chesapeake Energy Marketing, Inc., which is our only unrestricted subsidiary.

Some of our commodity price and financial 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 financial risk management transactions exceed certain levels. At June 30, 2003, we were required to post $23.0 million of collateral which we provided by a letter of credit under our credit facility. Future collateral requirements are uncertain and will depend on arrangements with our counterparties, highly volatile natural gas and oil prices, and fluctuations in interest rates.

Investing and Financing Transactions

We completed an acquisition of Mid-Continent gas assets from a wholly-owned subsidiary of ONEOK, Inc. in January 2003. We paid $296 million in cash for these assets, $15 million of which was paid in late 2002.

On March 5, 2003, we closed a private offering of $300 million in aggregate principal amount of senior notes, issued 23 million shares of common stock pursuant to a shelf registration statement and issued $230 million liquidation amount of convertible preferred stock in a private placement. Net proceeds from these transactions were used to finance the acquisition of oil and gas properties from El Paso Corporation and Vintage Petroleum, Inc. as discussed below and to repay indebtedness under our bank credit facility.

In March 2003, we acquired El Paso Corporation s Anadarko Basin assets in western Oklahoma and the Texas Panhandle for $500 million.

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In March 2003, we acquired Vintage Petroleum, Inc. s assets in the Bray field in southern Oklahoma for $29 million.

In March 2003, Chesapeake bought 5.3 million newly issued common shares of Pioneer Drilling Company, or 24.6% of its outstanding common shares, at $3.75 per share, for a total investment of $20 million.

On May 31, 2003, we acquired privately-owned Oxley Petroleum Company for $155 million. The acquired assets are primarily in the Arkoma Basin which is located in eastern Oklahoma and western Arkansas.

On July 16, 2003, we issued an additional $29.5 million of our 7.75% senior notes due 2015 in exchange for $27.9 million of our 8.375% senior notes due 2008 and $0.5 million of accrued interest, pursuant to a privately negotiated transaction. The $27.9 million of 8.375% senior notes due 2008 were promptly retired upon receipt.

On July 31, 2003, Chesapeake purchased oil and gas properties, a gathering system and a gas treatment plant from a major oil and gas company for $44.5 million.

On August 5, 2003, we issued an additional $33.5 million of our 7.75% senior notes due 2015 in exchange for $32.0 million of our 8.5% senior notes due 2012 and $1.1 million of accrued interest, pursuant to a privately negotiated transaction. The $32.0 million of 8.5% senior notes were retired upon receipt.

On August 13, 2003, we entered into an interest rate swap. The terms of this swap agreement are as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
August 2003 August 2005	$100,000,000	2.735%	U.S. six-month LIBOR in arrears

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 this interest rate swap will be made on February 15 and August 15 of each year beginning February 15, 2004.

Contingencies

Royalty owners have commenced litigation against a number of oil and gas producers claiming that amounts paid for production attributable to the royalty owners interest violated the terms of applicable leases and state law, that deductions from the proceeds of oil and gas production were unauthorized under the leases, and that amounts received by upstream sellers should be used to compute the amounts paid to the royalty owners. Typically this litigation has taken the form of class action suits. There are presently four such suits filed against Chesapeake, two in Texas and two in Oklahoma. No class has been certified in any of them. In one of the Oklahoma cases, we determined that a portion of the marketing fee we had charged royalty owners should be refunded. We have deposited with the court the aggregate amount of the fees we estimated should be refunded, $3.6 million, in an interest-bearing account for distribution to affected royalty owners. This amount has been charged to general and administrative expenses, of which $0.3 million was charged in the Current Period and the remainder was recorded in 2002. We do not believe any other claims made by royalty owners in the cases pending against us are valid. Even if the claims were upheld, we believe any damages awarded would not be material. This is a developing area of the law, however, and as new cases are decided, our potential liability relating to the marketing of oil and gas may increase or decrease. We will continue to monitor court decisions to ensure that our operations and practices minimize any exposure and to recognize any charges that may be appropriate when we can reasonably estimate a liability.

Critical Accounting Policies

We consider accounting policies related to stock options, hedging, oil and gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2002, except for our accounting policy related to stock options which is summarized in Note 1 of the notes to the consolidated financial statements included in our annual report on Form 10-K.

Statement of Financial Accounting Standards No. 141, *Business Combinations* and Statement of Financial Accounting Standards No. 142, *Goodwill and Intangible Assets* were issued by the Financial Accounting Standards Board in June 2001 and became effective for us on July 1, 2001 and January 1, 2002, respectively. SFAS 141 requires all business combinations initiated after June 30, 2001 to be accounted for using the purchase method.

Additionally, SFAS 141 requires companies to disaggregate and report separately from goodwill certain intangible assets. SFAS 142 establishes new guidelines for accounting for goodwill and other intangible assets. Under SFAS 142, goodwill and certain other intangible assets are not amortized, but rather are reviewed annually for impairment.

Oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract such reserves for both undeveloped and developed leaseholds may have to be classified separately from oil and gas properties as intangible assets on our condensed consolidated balance sheets. In addition, the disclosures required by SFAS 141 and 142 relative to intangibles would be included in the notes to the condensed consolidated financial statements. Historically, we, like many other oil and gas companies, have included these rights as part of oil and gas properties, even after SFAS 141 and 142 became effective.

As it applies to companies like us that have adopted full cost accounting for oil and gas activities, we understand that this interpretation of SFAS 141 and 142 would only affect our balance sheet classification of proved oil and gas leaseholds acquired after June 30, 2001 and all of our unproved oil and gas leaseholds. We would not be required to reclassify proved reserve leasehold acquisitions prior to June 30, 2001 because we did not separately value or account for these costs prior to the adoption date of SFAS 141. Our results of operations and cash flows would not be affected, since these oil and gas mineral rights held under lease and other contractual arrangements representing the right to extract oil and gas reserves would continue to be amortized in accordance with full cost accounting rules.

As of June 30, 2003 and December 31, 2002, we had undeveloped leaseholds of approximately $177.8 million and $72.5 million, respectively, that would be classified on our condensed consolidated balance sheet as intangible undeveloped leasehold and developed leaseholds of an estimated $1,423.0 million and $581.9 million, respectively, that would be classified as intangible developed leasehold if we applied the interpretation discussed above.

Recently Issued Accounting Standards

See Note 7 of the notes to the condensed 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 estimates of oil and gas reserves, expected oil and gas production and future expenditures, planned capital expenditures for drilling, leasehold acquisitions and seismic data, and statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures concerning 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 and subsequent filings with the Securities and Exchange Commission. These factors include:

the volatility of oil and gas prices,

adverse effects our substantial indebtedness could have on our operating and future growth,

our ability to compete effectively against strong independent oil and gas companies and majors,

the cost and availability of drilling and production services,

possible financial losses as a result of our commodity price management activities,

uncertainties inherent in estimating quantities of oil and gas reserves, including reserves we acquire, projecting future rates of production and the timing of development expenditures,

exposure to potential liabilities of acquired properties,

our ability to replace reserves,

the availability of capital,

changes in interest rates, and

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drilling and operating risks.

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.

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 the exposure to adverse market changes, we have entered into various derivative instruments. As of June 30, 2003, our oil and gas derivative instruments were comprised of swaps, cap-swaps 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. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty. Because this derivative includes a written put option (i.e., the cap), cap-swaps do not qualify for designation as cash flow hedges (in accordance with SFAS 133) since the combination of the hedged item and the written option do not provide as much potential for favorable cash flows as exposure to unfavorable cash flows.

Basis protection swaps are arrangements that guarantee a price differential of oil or 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.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap or cap-swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. At the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and gas sales in the month of related production.

When Chesapeake enters into a counter-swap with the same counterparty, to the extent that a right of setoff exists in accordance with FASB Interpretation No. 39, we net the value of the swap and the counter-swap.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap.

Chesapeake enters into oil and gas derivative transactions in order to mitigate a portion of its exposure to adverse market changes in oil and gas commodity prices. Accordingly, we believe that any associated gains or losses from the derivative transactions should be reflected as adjustments to oil and gas sales on the condensed consolidated statement of operations. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity

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(i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and gas sales.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributed to the hedged risk, are recorded in other comprehensive income. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales. These amounts totaled to a gain of $0.5 million in the Current Period and a loss of $2.2 million in the Prior Period, a gain of $0.4 million in the Current Quarter and a loss of $1.4 million in the Prior Quarter.

As of June 30, 2003, we had the following open oil and natural gas derivative instruments designed to hedge a portion of our oil and natural gas production for periods after June 2003:

	Volume mmbtu	Weighted-Average Strike Price	Weighted-Average Put Strike Price	Weighted Average Differential to NYMEX	Qualifies As SFAS 133 Hedge	Fair Value at June 30, 2003 ($ in thousands)
Natural Gas:						
Swaps:						
2003	69,910,000	5.69			Yes	12,084
2004	45,390,000	5.58			Yes	11,444
2005	25,550,000	4.83			Yes	(643)
2006	25,550,000	4.74			Yes	(268)
2007	25,550,000	4.76			Yes	(1,224)
Cap-Swaps:						
2003	25,760,000	3.59	2.59		No	(49,558)
Counter-Swaps:						
2003	(25,760,000)	3.74			No	45,799
Basis Protection Swaps:						
2003	82,800,000			(0.19)	No	4,339
2004	157,380,000			(0.17)	No	11,830
2005	109,500,000			(0.16)	No	8,861
2006	47,450,000			(0.16)	No	2,483
2007	63,875,000			(0.17)	No	2,248
2008	64,050,000			(0.17)	No	2,211
2009	36,500,000			(0.16)	No	1,457
Locked Swaps:						
2003					No	(2,222)
2004					No	793
Total Natural Gas						49,634

	Volume bbls	Weighted-Average Strike Price	Weighted-Average Put Strike Price	Weighted Average Differential to NYMEX	Qualifies As SFAS 133 Hedge	Fair Value at June 30, 2003 ($ in thousands)
Oil:						
Cap-Swaps:						
2003	1,896,000	28.06			No	(2,450)
2004	1,132,000	27.40			No	(981)
Total Oil						(3,431)
Total Natural Gas and Oil						$ 46,203

We have established the fair value of all derivative instruments first using estimates of fair value reported by our counterparties and subsequently by using established index prices and other sources. 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 June 30, 2003.

Additional information concerning the fair value of our oil and gas derivative instruments is as follows:

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	2003
	($ in thousands)
Fair value of contracts outstanding at January 1	$ (14,533)
Change in fair value of contracts during the period	(30,952)
Contracts realized or otherwise settled during the period	91,688
Fair value of new contracts when entered into during the period	
Fair value of contracts outstanding at June 30	$ 46,203

Based upon the market prices at June 30, 2003, we expect to transfer approximately $13.7 million of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the hedged transactions actually occur. All transactions hedged as of June 30, 2003 will mature by 2007, with the exception of the basis protection swaps which extend to 2009.

Derivative instruments reflected as current in the condensed consolidated balance sheets 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 date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

Interest Rate Hedging

We also utilize hedging strategies to manage interest rate exposure. Results from interest rate hedging transactions are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement.

In July 2002, we closed two interest rate swaps for a cash settlement of $8.6 million. As of June 30, 2003, the remaining balance to be amortized as a reduction to interest expense was $0.4 million. During the Current Quarter and Current Period, $0.2 million and $0.3 million, respectively, were recorded as a reduction to interest expense.

In March 1997, Chesapeake issued $150.0 million of 8.5% senior notes due 2012, of which $7.3 million were subsequently repurchased and retired. The 8.5% senior notes include a call option whereby Chesapeake may redeem the debt at declining redemption prices beginning in March 2004. This call option, also referred to as a right of optional redemption, allows Chesapeake to redeem the notes prior to their stated maturity date beginning in March 2004. This right of optional redemption has value depending upon changes in interest rates. Due to a decline in interest rates, Chesapeake effectively sold this optional redemption right to an unrelated third party (or counterparty) for $7.8 million in April 2002. In exchange for $7.8 million, Chesapeake gave the counterparty the option to elect whether or not to enter into an interest rate swap with Chesapeake on March 11, 2004. This transaction is more commonly referred to as a swaption. The terms of the interest rate swap, if executed by the counterparty, would be as follows:

Term	Notional Amount	Fixed Rate	Floating Rate
March 2004 March 2012	$142,665,000	8.5%	U.S. six-month LIBOR

plus 75 basis points

The interest rate swap would require Chesapeake to pay a fixed rate of 8.5% while the counterparty pays Chesapeake a floating rate of 6 month LIBOR in arrears plus 0.75%. Additionally, if the counterparty elects to enter into the interest rate swap on March 11, 2004, it may also elect to force Chesapeake to settle the transaction at the then current value of the interest rate swap.

This transaction does not alter Chesapeake s ability to redeem the 8.5% senior notes. Instead, it locks-in the economics of a future call. If interest rates are high and the swaption is not in-the-money , the counterparty will likely not elect to enter into the interest rate swap, the swaption will expire, and Chesapeake will amortize the $7.8 million premium as a reduction to interest expense over the remaining life of the notes. If interest rates are low and the swaption is in-the-money , the counterparty will likely exercise the swaption and force Chesapeake to settle the transaction at the then current value of the interest rate swap, and Chesapeake will amortize both the $7.8 million premium and the amount paid to the counterparty to interest expense over the remaining life of the notes. If Chesapeake elects to refinance the 8.5% senior notes, any unamortized premium or loss remaining related to the swaption would be included in the gain (or loss) on the early extinguishment of debt.

According to SFAS 133, a fair value hedge relationship exists between the embedded call option in the 8.5% senior notes and the swaption agreement. The fair value of the swaption is recorded on the condensed consolidated balance sheets as a liability, and the debt s carrying amount is adjusted by the change in the fair value of the call

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option subsequent to the initiation of the swaption. Any resulting differences are recorded currently as ineffectiveness in the condensed consolidated statements of operations as an adjustment to interest expense.

We have recorded an adjustment to the carrying value of the debt of $25.3 million as of June 30, 2003. Since the inception of the swaption, we recorded the change in the fair market value of the swaption from a $7.8 million liability to a $37.8 million liability, an increase of $30.0 million. As part of recording the fair value hedge, we also recorded, as an adjustment to the carrying value of the debt, an $25.3 million increase in the fair value of the embedded call option. The difference between the two adjustments, $4.7 million representing ineffectiveness, was recorded as additional interest expense. Results of the interest rate swap, if initiated, will be reflected as adjustments to interest expense in the corresponding months.

Interest Rate Risk

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.

	June 30, 2003							
	Years of Maturity							
	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt, including current portion fixed rate	$ 42.1	$	$	$	$ 250.0	$ 1,692.7	$ 1,984.8(1)	$ 2,131.3
Average interest rate	7.9%				8.4%	8.2%	8.2%	8.2%
Long-term debt variable rate	$	$	$	$ 26.0	$	$	$ 26.0	$ 26.0
Average interest rate				4.75%			4.75%	4.75%

(1) This amount does not include the discount of $(17.5) million, the value of the interest rate swap of $0.4 million and the value of the swaption of $(25.3) million which are all included in long-tem debt on the consolidated balance sheet.

ITEM 4. ***Controls and Procedures***

Our Chief Executive Officer and Chief Financial Officer, after evaluating the effectiveness of the company s disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of June 30, 2003, have concluded the company s disclosure controls and procedures are effective. No changes in the company s internal control over financial reporting occurred during the current quarter that have materially affected, or are reasonably likely to materially affect, the company s internal control over financial reporting.

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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.

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*

Two matters were submitted to a vote of the shareholders at Chesapeake s annual meeting of shareholders held on June 6, 2003: the election of directors and the adoption of a stock incentive plan for employees and consultants. In the election of directors, Breene M. Kerr received 201,132,123 votes for election and 3,376,386 votes were withheld from voting for Mr. Kerr; and Charles T. Maxwell received 196,750,064 votes for election and 7,758,445 votes were withheld from voting for Mr. Maxwell. The other directors whose terms continued after the meeting are Aubrey K. McClendon, Shannon T. Self, Tom L. Ward and Frederick B. Whittemore. In the adoption of our 2003 Stock Incentive Plan, 142,758,046 votes were received for the adoption of the Plan, 61,363,210 votes were received against adoption of the plan and 387,253 votes were withheld from voting on this proposal. There were no broker non-votes.

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**
4.8*	Third Amended and Restated Credit Agreement, dated as of May 30, 2003, among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership, as Borrower, Union Bank of California, N.A., as Administrative Agent and Collateral Agent, BNP Paribas and SunTrust Bank, as Co-Syndication Agents, Credit Lyonnais New York Branch and Toronto Dominion (Texas), Inc., as Co-Documentation Agents and the several lenders from time to time parties thereto.
12**	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
21*	Subsidiaries of Chesapeake.
31.1**	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2**	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1***	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2***	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Previously filed with the Form 10-Q on August 14, 2003.
** Filed with this Form 10-Q/A.
*** Furnished with this Form 10-Q/A.

(b) *Reports on Form 8-K*

During the quarter ended June 30, 2003, Chesapeake filed the following current reports on Form 8-K:

On April 10, 2003, we filed a current report on Form 8-K, furnishing under Item 9 a press release we issued on April 9, 2003 announcing updated first quarter and full-year 2003 guidance.

On April 29, 2003, we filed a current report on Form 8-K, furnishing under Item 9 and Item 12 a press release we issued on April 28, 2003 announcing results of operations, production and proved reserves for the first quarter 2003 and updated 2003 guidance.

On June 6, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on June 6, 2003 announcing the election of Governor Frank Keating to, and the retirement of Edgar J. Heizer, Jr. from, Chesapeake s Board of Directors. In addition, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on June 6, 2003 announcing the declaration of quarterly common and preferred stock dividends.

On June 24, 2003, we filed a current report on Form 8-K, furnishing under Item 9 a press release we issued on June 23, 2003 announcing our second quarter 2003 earnings release and conference call dates.

On June 25, 2003, we filed a current report on Form 8-K, reporting under Item 5 that we issued a press release on June 24, 2003 announcing $220 million of Mid-Continent natural gas acquisitions and furnishing under Item 9 our 2003 and 2004 production forecasts and updated hedging information.

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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

(Principal Executive Officer)

By: /s/ MARCUS C. ROWLAND

Marcus C. Rowland

Executive Vice President and

Chief Financial Officer

(Principal Financial Officer)

Date: September 18, 2003

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INDEX TO EXHIBITS

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