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

FORM 10-Q

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

For the quarterly period ended September 30, 2004

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

For the transition period from to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

Oklahoma (State or other jurisdiction of incorporation or organization)	**73-1395733** (I.R.S. Employer Identification No.)
6100 North Western Avenue **Oklahoma City, Oklahoma** (Address of principal executive offices)	**73118** (Zip Code)

(405) 848-8000
Registrant's telephone number, including area code

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

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

As of November 4, 2004, there were 269,912,045 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2004

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2004	December 31, 2003
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 49,073	$ 40,581
Accounts receivable:		
Oil and gas sales	238,142	173,792
Joint interest, net of allowances of $4,484,000 and $2,669,000, respectively	60,098	37,789
Related parties	7,372	2,983
Other	34,295	26,830
Deferred income tax asset	100,129	36,705
Short-term derivative instruments	1,034	4,467
Inventory and other	30,375	19,257
Total Current Assets	520,518	342,404
PROPERTY AND EQUIPMENT:		
Oil and gas properties, at cost based on full-cost accounting:		
Evaluated oil and gas properties	8,807,355	6,221,576
Unevaluated properties	629,210	227,331
Less: accumulated depreciation, depletion and amortization of oil and gas properties	(2,887,192)	(2,480,261)
Total oil and gas properties, at cost based on full-cost accounting	6,549,373	3,968,646
Other property and equipment	321,233	225,891
Less: accumulated depreciation and amortization of other property and equipment	(77,879)	(61,420)
Total Property and Equipment	6,792,727	4,133,117
OTHER ASSETS:		
Long-term derivative instruments	—	17,493
Long-term investments	43,589	31,544
Other assets	69,457	47,733
Total Other Assets	113,046	96,770
TOTAL ASSETS	$ 7,426,291	$ 4,572,291
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 348,421	$ 164,264
Accrued interest	46,696	46,648
Short-term derivative instruments	270,875	92,651
Other accrued liabilities	154,266	108,020
Revenues and royalties due others	152,752	101,573
Total Current Liabilities	973,010	513,156
LONG-TERM LIABILITIES:		
Long-term debt, net	2,762,425	2,057,713
Revenues and royalties due others	22,112	13,921
Asset retirement obligation	68,166	48,812
Long-term derivative instruments	21,694	4,736
Deferred income tax liability	740,895	191,026
Other liabilities	14,674	10,117
Total Long-term Liabilities	3,629,966	2,326,325
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, 20,000,000 and 10,000,000 shares authorized as of September 30, 2004 and December 31, 2003, respectively:		
6.75% cumulative convertible preferred stock, 2,714,200 and 2,998,000 shares issued and outstanding as of September 30, 2004 and December 31, 2003, respectively, entitled in liquidation to $135,710,000 and $149,900,000	135,710	149,900
6.00% cumulative convertible preferred stock, 4,600,000 shares issued and outstanding as of September 30, 2004 and December 31, 2003, entitled in liquidation to $230,000,000	230,000	230,000
5.00% cumulative convertible preferred stock, 1,725,000 shares issued and outstanding as of September 30, 2004 and December 31, 2003, entitled in liquidation to $172,500,000	172,500	172,500
4.125% cumulative convertible preferred stock, 313,250 and 0 shares issued and outstanding as of September 30, 2004 and December 31, 2003, entitled in liquidation to $313,250,000	313,250	—
Common Stock, $0.01 par value, 500,000,000 and 350,000,000 shares authorized, 274,790,035 and 221,855,894 shares issued as of September 30, 2004 and December 31, 2003, respectively	2,748	2,218
Paid-in capital	2,074,691	1,389,212
Accumulated earnings (deficit)	73,379	(168,617)
Accumulated other comprehensive loss, net of tax of $68,863,000 and $12,449,000, respectively	(122,423)	(20,312)
Unearned compensation	(34,449)	—
Less: treasury stock, at cost; 5,072,121 and 5,071,571 common shares as of September 30, 2004 and December 31, 2003, respectively	(22,091)	(22,091)
Total Stockholders' Equity	2,823,315	1,732,810
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 7,426,291	$ 4,572,291

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	($ in thousands, except per share data)			
REVENUES:				
Oil and gas sales	$ 450,936	$ 345,587	$1,270,394	$ 951,125
Oil and gas marketing sales	178,860	108,962	496,823	309,566
Total Revenues	629,796	454,549	1,767,217	1,260,691
OPERATING COSTS:				
Production expenses	54,102	35,944	148,500	101,664
Production taxes	30,872	21,638	68,559	57,336
General and administrative expenses:				
General and administrative (excluding stock based compensation)	8,361	4,726	23,947	15,740
Stock based compensation	584	147	3,125	512
Oil and gas marketing expenses	175,426	105,849	486,205	302,064
Oil and gas depreciation, depletion and amortization	153,586	97,947	410,237	266,131
Depreciation and amortization of other assets	7,700	4,841	20,155	12,647
Provision for legal settlements	—	716	—	1,002
Total Operating Costs	430,631	271,808	1,160,728	757,096
INCOME FROM OPERATIONS	199,165	182,741	606,489	503,595
OTHER INCOME (EXPENSE):				
Interest and other income	885	(188)	3,563	1,356
Interest expense	(48,689)	(40,851)	(124,040)	(115,891)
Loss on repurchases or exchanges of Chesapeake debt	—	—	(6,925)	—
Total Other Income (Expense)	(47,804)	(41,039)	(127,402)	(114,535)
INCOME BEFORE INCOME TAX AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	151,361	141,702	479,087	389,060
INCOME TAX EXPENSE:				
Current	—	330	—	330
Deferred	54,489	53,513	172,470	147,511
Total Income Tax Expense	54,489	53,843	172,470	147,841
NET INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	96,872	87,859	306,617	241,219
CUMULATIVE EFFECT OF ACCOUNTING CHANGE, NET OF INCOME TAXES OF $1,464,000	—	—	—	2,389
NET INCOME	96,872	87,859	306,617	243,608
PREFERRED STOCK DIVIDENDS	(11,287)	(5,979)	(30,799)	(15,484)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 85,585	$ 81,880	$ 275,818	$ 228,124
EARNINGS PER COMMON SHARE — BASIC:				
Income before cumulative effect of accounting change	$ 0.33	$ 0.38	$ 1.13	$ 1.08
Cumulative effect of accounting change	—	—	—	0.01
	$ 0.33	$ 0.38	$ 1.13	$ 1.09
EARNINGS PER COMMON SHARE — ASSUMING DILUTION:				
Income before cumulative effect of accounting change	$ 0.29	$ 0.33	$ 0.98	$ 0.95
Cumulative effect of accounting change	—	—	—	0.01
	$ 0.29	$ 0.33	$ 0.98	$ 0.96
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.045	$ 0.035	$ 0.125	$ 0.100
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):				
Basic	257,096	216,080	245,087	209,394
Assuming dilution	319,473	265,545	307,438	253,567

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 306,617	$ 243,608
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	426,404	273,479
Deferred income taxes	172,470	149,305
Unrealized (gains) losses on derivatives	72,512	(28,335)
Amortization of loan costs and bond discount	7,288	6,358
Cumulative effect of accounting change	—	(3,853)
Loss on repurchases or exchanges of Chesapeake debt	6,925	—
Income from equity investments	(786)	259
Stock-based compensation	3,125	—
Other	569	670
Cash provided by operating activities before changes in assets and liabilities	995,124	641,491
Changes in assets and liabilities	43,082	12,026
Cash provided by operating activities	1,038,206	653,517
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	(1,657,481)	(1,022,975)
Exploration and development of oil and gas properties	(888,288)	(518,799)
Additions to buildings and other fixed assets	(77,073)	(54,430)
Divestitures of oil and gas properties	271	21,218
Cash paid for investments and other assets	(26,740)	(25,917)
Additions to drilling rig equipment	(19,315)	(123)
Other	385	258
Cash used in investing activities	(2,668,241)	(1,600,768)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	1,413,000	485,000
Payments on long-term borrowings	(1,261,000)	(413,000)
Proceeds from issuance of senior notes, net of offering costs	582,889	290,939
Proceeds from issuance of preferred stock, net of offering costs	304,936	222,893
Proceeds from issuance of common stock, net of offering costs	624,187	177,444
Cash paid to purchase or exchange senior notes, including redemption premium	(57,320)	—
Cash paid for common stock dividend	(26,886)	(19,679)
Cash paid for preferred stock dividend	(30,257)	(14,872)
Net increase in outstanding payments in excess of cash balances	89,321	6,341
Cash paid for financing cost of credit facilities	(8,737)	(2,403)
Cash received from exercise of stock options	9,047	7,787
Cash paid for treasury stock	—	(2,109)
Other financing costs	(653)	(249)
Cash provided by financing activities	1,638,527	738,092
Net increase (decrease) in cash and cash equivalents	8,492	(209,159)
Cash and cash equivalents, beginning of period	40,581	247,637
Cash and cash equivalents, end of period	$ 49,073	$ 38,478

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	($ in thousands)			
Net Income	$ 96,872	$ 87,859	$ 306,617	$ 243,608
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of ($20,586,000), $37,112,000, ($83,149,000), and $14,521,000	(36,598)	60,551	(147,820)	23,692
Reclassification of loss (gain) on settled contracts, net of income taxes of $7,917,000, ($8,600,000), $19,586,000 and $24,099,000	14,075	(14,032)	34,819	39,320
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $643,000, ($2,029,000), $6,126,000 and ($2,205,000)	1,143	(3,311)	10,890	(3,597)
Comprehensive Income	$ 75,492	$ 131,067	$ 204,506	$ 303,023

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation and its 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. Certain reclassifications have been made to the condensed consolidated financial statements for 2003 to conform the presentation used for the 2004 condensed consolidated financial statements. The results for the three and nine months ended September 30, 2004 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and nine months ended September 30, 2004 (the "Current Quarter" and "Current Period", respectively) and the three and nine months ended September 30, 2003 (the "Prior Quarter" and "Prior Period", respectively).

Stock Based Compensation

Stock Options - Chesapeake has elected to follow APB No. 25, *Accounting for Stock Issued to Employees,* and related interpretations in accounting for its employee and director stock options. Under APB No. 25, compensation expense is recognized for the difference between the option price and market value on the measurement date. The original issuance of stock options has not resulted in the recognition of compensation expense because the exercise price of the stock options granted under the plans has equaled the market price of the underlying stock on the date of grant. Pursuant to Financial Accounting Standards Board Interpretation No. 44 (FIN 44), however, we recognized stock based compensation expense (a sub-category of general and administrative costs) in the condensed consolidated statements of operations of $0.3 million, $0.1 million, $0.5 million and $0.5 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively, as a result of modifications to fixed-price stock options that were made during 2000, 2001, 2003 and 2004.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	($ in thousands, except per share amounts)			
Net Income				
As reported	$ 96,872	$ 87,859	$ 306,617	$ 243,608
Add stock based compensation expense included in net income, net of tax	374	91	2,000	317
Less pro forma compensation expense, net of tax	(3,152)	(3,078)	(10,647)	(8,317)
Pro Forma	$ 94,094	$ 84,872	$ 297,970	$ 235,608
Basic earnings per common share				
As reported	$ 0.33	$ 0.38	$ 1.13	$ 1.09
Pro Forma	$ 0.32	$ 0.37	$ 1.09	$ 1.05
Diluted earnings per common share				
As reported	$ 0.29	$ 0.33	$ 0.98	$ 0.96
Pro Forma	$ 0.28	$ 0.32	$ 0.95	$ 0.93

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.

Restricted Stock - During the Current Period, Chesapeake issued 2.7 million shares of restricted common stock to employees. The total value of restricted shares granted is recorded as unearned compensation in stockholders' equity based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is four years from the date of grant. To the extent amortization of compensation cost relates to employees directly involved in acquisition, exploration and development activities, such amounts are capitalized to oil and gas properties. Amounts not associated with oil and gas properties are recognized in stock based compensation expense (a sub-category of general and administrative costs). Chesapeake recognized amortization of compensation cost related to restricted stock totaling $0.4 million and $3.9 million in the Current Quarter and Current Period, respectively. Of these amounts, $0.3 million and $2.6 million are reflected in stock based compensation expense (a sub-category of general and administrative costs) in the Current Quarter and Current Period, respectively, with the remaining $0.1 million and $1.3 million capitalized to oil and gas properties. As of September 30, 2004, the unamortized balance of unearned compensation recorded as a reduction of stockholders' equity was $34.4 million.

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, 2003, 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 sets forth 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. Consistent with oil and gas accounting and industry practice, Chesapeake classifies the cost of oil and gas mineral rights as property and equipment and not as intangible assets.

In September 2004, the FASB finalized FASB Staff Position, FSP SFAS 142-2, *Application of FASB Statement No. 142 to Oil and Gas Producing Entities*. The FSP clarifies that an exception in SFAS 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities. The FASB staff acknowledges that the existing accounting framework for oil and gas producers is based on the level of established reserves, not whether an asset is tangible or intangible. The FSP confirms Chesapeake's historical treatment of these costs.

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 September 30, 2004, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. 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, Chesapeake receives a fixed price for the hedged commodity and pays 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 put option does 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.

- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking in the value of a 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 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.

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. Changes in the value of cap-swaps and the counter-swaps are recorded as adjustments to oil and gas sales.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets, to the extent that a legal right of setoff exists.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the condensed consolidated statements 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 were ($32.5) million, $0.6 million, ($66.6) million and $33.7 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. These amounts include the gains (losses) on ineffectiveness discussed below.

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 attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as an unrealized gain (loss). We recorded a gain (loss) on ineffectiveness of ($1.8) million, $5.3 million, ($17.0) million and $5.8 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively

The estimated fair values of our oil and gas derivative instruments as of September 30, 2004 and December 31, 2003 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2004	December 31, 2003
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price gas swaps	$ (119,060)	$ (44,794)
Fixed-price gas locked swaps	(81,291)	1,777
Fixed-price gas cap-swaps	(86,621)	(18,608)
Fixed-price gas counter-swaps	4,439	—
Gas basis protection swaps	91,346	46,205
Gas call options (a)	(13,484)	(17,876)
Fixed-price gas collars	(11,290)	—
Fixed-price oil swaps	(7,660)	—
Fixed-price oil cap-swaps	(33,600)	(11,692)
Estimated fair value	$ (257,221)	$ (44,988)

(a) After adjusting for the remaining $5.7 million and $16.8 million premium paid to Chesapeake by the counterparty, the cumulative unrealized loss related to these call options as of September 30, 2004 and December 31, 2003 was ($7.8) million and ($1.1) million, respectively.

Based upon the market prices as of September 30, 2004, we expect to transfer a loss of approximately $97.3 million from accumulated other comprehensive income to earnings during the next 12 months when the hedged transactions actually close. All hedged transactions as of September 30, 2004 are expected to mature by December 31, 2007, with the exception of the basis protection swaps which extend through 2009.

In May 2004, we entered into a secured natural gas hedging facility with a nationally recognized counterparty. Under this hedging facility, which matures in May 2009, we can enter into cash-settled natural gas commodity transactions, valued by the counterparty, for up to $600 million. Outstanding transactions under the facility are collateralized by certain oil and gas properties, exclusive of the oil and gas properties that collateralize our revolving bank credit facility. The hedging facility is subject to an annual fee of 0.30% of the maximum total capacity and a 1.0% exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of September 30, 2004, the fair market value of the natural gas hedging transactions related to the hedging facility was ($7.2) million.

The hedging facility contains the standard representations and default provisions that are typical of such agreements. The agreement also contains various restrictive provisions which govern the aggregate gas production volumes that we are permitted to hedge under all of our agreements at any one time. The hedging facility is guaranteed by Chesapeake and all of its subsidiaries.

Interest Rate Derivatives

We also utilize hedging strategies to manage our exposure to changes in interest rates. To the extent the interest rate swaps have been designated as fair value hedges, changes in the fair value of the derivative instrument and the corresponding debt are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

In the Current Quarter, we entered into the following interest rate swaps to convert a portion of our long-term fixed rate debt to floating rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value as of September 30, 2004 ($ in thousands)
September 2004 – August 2012	$75,000,000	9.00%	6-month LIBOR plus 452 basis points	$ 988
September 2004 – January 2015	$75,000,000	7.75%	6-month LIBOR plus 293.75 basis points	$ (781)
August 2004 – June 2014	$75,000,000	7.50%	6-month LIBOR in arrears plus 254 basis points	$ 46
August 2004 – August 2014	$75,000,000	7.00%	6-month LIBOR in arrears plus 191 basis points	—

In September 2004, we closed the 7.00% interest rate swap listed above and received a cash settlement of $1.0 million. In October 2004, we closed the 7.50% and 7.75% interest rate swaps listed above and received cash settlements of $0.4 million and $0.5 million, respectively. Such settlement amounts will be amortized as a reduction to realized interest expense over the remaining terms of our 7.00%, 7.50% and 7.75% senior notes.

In March 2004, Chesapeake entered into an interest rate swap which requires Chesapeake to pay a fixed rate of 8.68% while the counterparty pays Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. The counterparty may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap on March 15, 2005 and annually thereafter through March 15, 2011. The interest rate swap expires on March 15, 2012. Chesapeake may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap at any time during the term of the swap.

As of September 30, 2004, the fair value of the interest rate swap was a liability of $34.3 million. Because the interest rate swap is not designated as a fair value hedge, changes in the fair value of the swap are recorded as adjustments to interest expense. The Current Quarter and Current Period include an unrealized loss of $5.9 million and $4.8 million, respectively, and a realized loss of $0.7 million and $1.5 million, respectively, in interest expense.

In January 2004, Chesapeake acquired a $50 million interest rate swap as part of the purchase of Concho Resources Inc. Under the terms of the interest rate swap, the counterparty pays Chesapeake a floating three month LIBOR rate and Chesapeake pays a fixed rate of 2.875%. Payments are made quarterly and the interest rate swap extends through September 2005. An initial liability of $0.6 million was recorded based on the fair value of the interest rate swap at the time of acquisition. As of September 30, 2004, the interest rate swap had a fair value of ($0.2) million. Because this instrument is not designated as a fair value hedge, an unrealized loss of $0.2 million and a negligible unrealized gain were recognized in the Current Quarter and Current Period, respectively, as part of interest expense.

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair value amounts by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of items comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term, fixed-rate debt using primarily quoted market prices. Our carrying amount for such debt, excluding premium (discount) for interest rate swaps, as of September 30, 2004 and December 31, 2003 was $2,609.2 million and $2,058.1 million, respectively, compared to approximate fair values of $2,892.4 million and $2,279.5 million, respectively. The carrying amounts for our 6.75% convertible preferred stock, 6.00% convertible preferred stock, 5.00% convertible preferred stock and 4.125% convertible preferred stock as of September 30, 2004 were $135.7 million, $230.0 million, $172.5 million and $313.3 million, respectively, with a fair value of $249.7 million, $322.0 million, $199.5 million and $313.3 million, respectively.

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 equity investments 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 generally exceed the federally insured limits.

3. Contingencies and Commitments

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

Employment Agreements with Officers. 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 January 1, 2004. The term of each agreement is automatically extended for one additional year on each January 31 unless the company provides 30 days prior notice of non-extension or the parties otherwise terminate the agreement. The agreements with the chief financial officer and other senior managers expire on September 30, 2006. The company's employment agreements with the executive officers provide for payments in the event of a change in control. The chief executive officer and chief operating officer are each entitled to receive a payment in the amount of five times their 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 two times the sum of their base compensation and bonuses paid during the prior year.

Environmental Risk. 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 our 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 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 as of September 30, 2004.

4. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share (EPS)*, 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 and Prior Period, outstanding warrants to purchase 0.4 million shares of common stock at a weighted-average exercise price of $14.55 were antidilutive because the exercise price of the warrants was greater than the average market price of the common stock.
- For the Current Quarter, the Prior Quarter, Current Period and Prior Period, outstanding options to purchase 0.2 million, 0.2 million, 0.1 million and 1.3 million shares of common stock at a weighted-average exercise price of $22.72, $19.21, $23.58 and $11.60, respectively, were antidilutive because the exercise prices of the options were greater than the average market price of the common stock.

Under SFAS 128, we did not assume the conversion of our 4.125% cumulative convertible preferred stock into 18,812,385 common shares (at a conversion price of $16.65 per share) because the holders did not have the right to convert. A holder's right to convert will only arise when the closing sales price of our common stock reaches, or the trading price of the preferred stock falls below, specified thresholds or upon the occurrence of specified corporate transactions.

The Emerging Issues Task Force (EITF) Issue 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings Per Share*, which was issued in September 2004, provides new guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. The new guidance states that these securities should be included in the diluted EPS computation regardless of whether the market price trigger has been met. The guidance in EITF 04-8 is effective for all periods ending after December 15, 2004 and would be applied by retrospectively restating previously reported EPS. Accordingly, effective December 15, 2004, the company will assume the conversion of the 4.125% convertible preferred shares (if dilutive) for purposes of determining earnings per share assuming dilution. The company has determined that the impact of this new guidance on prior period earnings per share is not material.

During the Current Quarter, holders of our 6.75% preferred stock converted 283,600 shares into 1,841,556 shares of common stock (at a conversion price of $7.70 per share). During November 2004, we expect to cause conversion of the remaining 6.75% preferred stock into 17,624,657 shares of common stock.

Reconciliations for the three and nine months ended September 30, 2004 and 2003 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Three Months Ended September 30, 2004:			
Basic EPS:			
Income available to common shareholders	$ 85,585	257,096	$ 0.33
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.00% convertible preferred stock	—	10,516	
Common shares assumed issued for 6.00% convertible preferred stock	—	22,358	
Common shares assumed issued for 6.75% convertible preferred stock	—	17,625	
Common stock equivalent of preferred stock outstanding prior to conversion, 6.75% convertible preferred stock		1,621	
Preferred stock dividends	11,287	—	
Preferred stock dividends on 4.125% convertible preferred stock	(3,230)	—	
Employee stock options	—	9,992	
Restricted stock	—	249	
Warrants assumed in Gothic Acquisition	—	16	
Diluted EPS Income available to common shareholders and assumed conversions	$ 93,642	319,473	$ 0.29
For the Three Months Ended September 30, 2003:			
Basic EPS:			
Income available to common shareholders	$ 81,880	216,080	$ 0.38
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 6.00% convertible preferred stock	—	22,358	
Common shares assumed issued for 6.75% convertible preferred stock	—	19,468	
Preferred stock dividends	5,979	—	
Employee stock options	—	7,639	
Diluted EPS Income available to common shareholders and assumed conversions	$ 87,859	265,545	$ 0.33
For the Nine Months Ended September 30, 2004:			
Basic EPS:			
Income available to common shareholders	$ 275,818	245,087	$ 1.13
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.00% convertible preferred stock	—	10,516	
Common shares assumed issued for 6.00% convertible preferred stock	—	22,358	
Common shares assumed issued for 6.75% convertible preferred stock	—	17,625	
Common stock equivalent of preferred stock outstanding prior to conversion, 6.75% convertible preferred stock	—	1,774	
Preferred stock dividends	30,799	—	
Preferred stock dividends on 4.125% convertible preferred stock	(6,470)	—	
Employee stock options	—	9,927	
Restricted stock	—	142	
Warrants assumed in Gothic Acquisition	—	9	
Diluted EPS Income available to common shareholders and assumed conversions	$ 300,147	307,438	$ 0.98

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in thousands, except per share data)		
For the Nine Months Ended September 30, 2003:			
Income before cumulative effect of accounting change, net of tax	$ 241,219		
Preferred stock dividends	(15,484)		
Basic EPS:			
Income available to common shareholders before cumulative effect of accounting change, net of tax	$ 225,735	209,394	$ 1.08
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 6.00% convertible preferred stock	—	17,198	
Common shares assumed issued for 6.75% convertible preferred stock	—	19,468	
Preferred stock dividends	15,484	—	
Employee stock options	—	7,507	
Diluted EPS Income available to common shareholders before cumulative effect of accounting change, net of tax	$ 241,219	253,567	$ 0.95

5. Notes Payable and Revolving Credit Facility

Our long-term debt consisted of the following as of September 30, 2004 and December 31, 2003:

	September 30, 2004	December 31, 2003
	($ in thousands)	
8.375% Senior Notes due 2008	$ 209,815	$ 209,815
8.125% Senior Notes due 2011	245,407	728,255
9.0% Senior Notes due 2012	300,000	300,000
7.5% Senior Notes due 2013	363,823	363,823
7.0% Senior Notes due 2014	300,000	—
7.5% Senior Notes due 2014	300,000	—
7.75% Senior Notes due 2015	300,408	236,691
6.875% Senior Notes due 2016	670,437	200,000
7.875% Senior Notes due 2004	—	42,137
8.5% Senior Notes due 2012	—	4,290
Revolving bank credit facility	152,000	—
Discount on senior notes	(80,661)	(26,959)
Premium (discount) for interest rate swaps and swaption	1,196	(339)
Total notes payable and long-term debt	$ 2,762,425	$ 2,057,713

On August 2, 2004, we issued $300 million principal amount of 7.0% Senior Notes due 2014 in a private placement. These notes were exchanged on October 19, 2004 for substantially identical notes registered under the Securities Act of 1933.

On May 27, 2004, we issued $300 million principal amount of 7.5% Senior Notes due 2014 in a private placement. These notes were exchanged on August 6, 2004 for substantially identical notes registered under the Securities Act of 1933.

On January 14, 2004, we completed a public exchange offer in which we retired $458.5 million of our 8.125% Senior Notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% Senior Notes due 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% Senior Notes due 2016 and $4.1 million of accrued interest. In connection with this exchange, we recorded a pre-tax charge of $6.0 million, consisting of a $5.7 million underwriter's fee and $0.3 million in other transaction costs.

In January and February of 2004, we issued an additional $37.0 million of our 6.875% Senior Notes due 2016 and $0.5 million of accrued interest in exchange for $24.3 million of our 8.125% Senior Notes due 2011 and $0.7 million of accrued interest and $9.1 million of our 7.75% Senior Notes due 2015 and $0.1 million of accrued interest in four private exchange transactions.

On November 12, 2003, we commenced a tender offer to purchase for cash our $110.7 million aggregate principal amount of 8.5% Senior Notes due 2012 and concurrently conducted a consent solicitation to amend the indenture governing the 8.5% Senior Notes. On December 10, 2003, we purchased $106.4 million principal amount of 8.5% Senior Notes tendered, which represented approximately 96% of the outstanding aggregate principal amount of the 8.5% Senior Notes, and we amended the indentures eliminating substantially all of the restrictive covenants. We redeemed the remaining $4.3 million of 8.5% Senior Notes on March 15, 2004. In connection with the redemption, we recorded a pre-tax loss of $0.9 million, consisting of $0.2 million of redemption premium, $0.1 million of unamortized debt issue costs and discount on senior notes and $0.6 million carried as a discount on the 8.5% Senior Notes based on the hedging relationship between the notes and a swaption.

On March 15, 2004, we paid $42.1 million to retire the balance outstanding on our 7.875% Senior Notes that matured on that date.

The senior note indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures contain covenants limiting us and our 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; mergers or consolidations; and transactions with affiliates.

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 all of our subsidiaries including Chesapeake Energy Marketing, Inc., Mayfield Processing, LLC and MidCon Compression, L.P., for which the guarantee became effective on September 21, 2004.

We have a $600 million revolving bank credit facility (with current bank commitments of $500 million) which matures in June 2008. As of September 30, 2004, we had $152.0 million of outstanding borrowings under this facility and utilized $73.9 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 (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies according to our senior unsecured long-term debt ratings. Currently, the annual commitment fee rate is 0.30%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. We plan to increase the commitments under the revolving bank credit facility to $600 million in November 2004.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, sell properties, purchase or redeem our capital stock, make investments or loans, and create liens. The credit facility agreement requires us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio (as defined) of at least 2.5 to 1. As of September 30, 2004, our current ratio was 1.13 to 1 and our fixed charge coverage ratio was 5.19 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $35.0 million.

6. Segment Information

In accordance with SFAS 131, *Disclosures about Segments of an Enterprise and Related Information*, we have identified two reportable operating segments. These segments are managed separately because of the nature of their products and services. Chesapeake's two segments are the exploration and production segment and the marketing segment. The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, transporting, and selling natural gas and crude oil production primarily from Chesapeake operated wells. Revenues from the marketing segment's sale of oil and gas related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled $349.6 million and $224.8 million for the Current Quarter and Prior Quarter, respectively, and $932.0 million and $654.7 million for the Current Period and Prior Period, respectively.

Management has determined that these are its only two segments and any assets that do not support the marketing segment are considered part of the exploration and production segment. Management evaluates each segment's performance based upon income before income taxes and cumulative effect of accounting change. The following table presents information about each segment's operations:

	Exploration and Production	Marketing	Total
		($ in thousands)	
Three months ended September 30, 2004:			
Revenues	$ 450,936	$ 178,860	$ 629,796
Income before income taxes and cumulative effect of accounting change	151,714	(353)	151,361
Three months ended September 30, 2003:			
Revenues	$ 345,587	$ 108,962	$ 454,549
Income before income taxes and cumulative effect of accounting change	140,253	1,449	141,702
Nine months ended September 30, 2004:			
Revenues	$ 1,270,394	$ 496,823	$ 1,767,217
Income before income taxes and cumulative effect of accounting change	478,127	960	479,087
Nine months ended September 30, 2003:			
Revenues	$ 951,125	$ 309,566	$ 1,260,691
Income before income taxes and cumulative effect of accounting change	385,120	3,940	389,060
As of September 30, 2004:			
Total assets	$ 7,188,526	$ 237,765	$ 7,426,291
As of December 31, 2003:			
Total assets	$ 4,376,558	$ 195,733	$ 4,572,291

7. Acquisitions and Related Financing

We completed the acquisition of Concho Resources Inc. in January 2004 to acquire oil and gas interests primarily in the Permian Basin and the Mid-Continent. We paid $420 million in cash for these assets, $10 million of which was paid in 2003. We also paid $12 million in employee severance and other transaction costs at closing. We recorded a $127 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. We also completed an acquisition of Texas Gulf Coast properties in January 2004 from a private company. We paid $65 million for these assets, $3.3 million of which was paid in 2003. On January 14, 2004, we issued 23,000,000 shares of common stock at a price to the public of $13.51 per share. We used the net proceeds of approximately $298.1 million to finance a portion of the acquisitions completed in January 2004.

On March 30, 2004, we issued 275,000 shares of 4.125% convertible preferred stock having a liquidation preference of $1,000 per share in a private placement. In April 2004, the original purchasers exercised their option to purchase an additional 38,250 shares of 4.125% convertible preferred stock on the same terms and conditions. We used the net proceeds from these issuances of approximately $304.9 million to pay the outstanding borrowings under our bank credit facility which were incurred to finance a portion of the acquisitions completed in the first quarter of 2004. As of September 30, 2004, 18.8 million shares of common stock were reserved for issuance upon conversion of the 4.125% convertible preferred stock.

We completed a $425 million acquisition of privately-held Greystone Petroleum, LLC in June 2004 to acquire natural gas assets in the Ark-La-Tex region of northern Louisiana. We recorded a $46 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. On May 27, 2004, we issued $300.0 million principal amount of 7.5% senior notes due 2014 in a private placement. We used the net proceeds of approximately $288.6 million, along with borrowings from the bank credit facility and cash on hand, to finance the Greystone acquisition.

We completed a $335 million acquisition of Bravo Natural Resources, Inc. in August 2004 to acquire oil and gas interests in the Anadarko Basin. We recorded a $177 million deferred tax liability to reflect the tax effect of the cost in excess of the tax basis acquired. We also completed the acquisition of South Texas oil and gas assets from Legend Natural Gas, LLP in August 2004. We paid $215 million in cash for these assets which are located primarily in Zapata County, Texas. In addition, we completed the acquisition of substantially all of the Mid-Continent oil and gas assets of Tilford Pinson Exploration, LLC in July 2004. We paid $20 million in cash for these assets.

In August 2004, we completed a private offering of $300 million principal amount of 7.0% Senior Notes due 2014 and issued 23 million shares of common stock at a price to the public of $14.75 per share. Net proceeds of $620.5 million from these transactions were used to finance the Bravo, Legend and Tilford Pinson acquisitions and to repay amounts outstanding under our bank credit facility.

In addition to the acquisitions mentioned previously, we invested approximately $190 million to acquire various other oil and gas properties during the Current Period. These acquisitions are primarily located in the Mid-Continent region and include both corporate and asset purchases.

8. Recently Issued Accounting Standards

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin 106 which summarizes the views of the staff regarding the application of SFAS 143, *Accounting for Asset Retirement Obligations*, by oil and gas producing companies following the full cost accounting method. This bulletin will be effective in the Fourth Quarter of 2004. Implementation of this pronouncement is not expected to have a material effect on our financial statements.

In September 2004, the Emerging Issues Task Force issued EITF No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. EITF No. 04-8 provides new guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. The guidance in EITF No. 04-8 is effective for all periods ending after December 15, 2004 and Chesapeake will comply by retrospectively restating previously reported EPS. The effect of this pronouncement on diluted EPS is more fully described in Note 4 to these interim condensed consolidated financial statements.

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 three and nine months ended September 30, 2004 (the "Current Quarter" and "Current Period", respectively) and the three and nine months ended September 30, 2003 (the "Prior Quarter" and "Prior Period", respectively) :

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
Net Production:				
Oil (mbbl)	1,834	1,216	4,972	3,500
Gas (mmcf)	83,219	63,684	229,827	174,066
Gas equivalent (mmcfe)	94,223	70,980	259,659	195,066
Oil and Gas Sales ($ in thousands):				
Oil sales	$ 73,921	$ 33,908	$ 181,882	$ 101,811
Oil derivatives – realized gains (losses)	(20,464)	(2,045)	(41,672)	(8,924)
Oil derivatives – unrealized gains (losses)	(14,436)	185	(21,925)	(993)
Total oil sales	39,021	32,048	118,285	91,894
Gas sales	447,466	293,309	1,222,783	889,598
Gas derivatives – realized gains (losses)	(17,514)	19,781	(25,976)	(65,028)
Gas derivatives – unrealized gains (losses)	(18,037)	449	(44,698)	34,661
Total gas sales	411,915	313,539	1,152,109	859,231
Total oil and gas sales	$ 450,936	$ 345,587	$1,270,394	$ 951,125
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 40.31	$ 27.88	$ 36.58	$ 29.09
Gas ($ per mcf)	$ 5.38	$ 4.61	$ 5.32	$ 5.11
Gas equivalent ($ per mcfe)	$ 5.53	$ 4.61	$ 5.41	$ 5.08
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 29.15	$ 26.20	$ 28.20	$ 26.54
Gas ($ per mcf)	$ 5.17	$ 4.92	$ 5.21	$ 4.74
Gas equivalent ($ per mcfe)	$ 5.13	$ 4.86	$ 5.15	$ 4.70
Expenses ($ per mcfe):				
Production expenses	$ 0.57	$ 0.51	$ 0.57	$ 0.52
Production taxes (a)	$ 0.33	$ 0.30	$ 0.26	$ 0.29
General and administrative expenses:				
General and administrative expenses (excluding stock based compensation)	$ 0.09	$ 0.07	$ 0.09	$ 0.08
Stock based compensation	$ 0.01	$ —	$ 0.01	$ —
Oil and gas depreciation, depletion and amortization	$ 1.63	$ 1.38	$ 1.58	$ 1.36
Depreciation and amortization of other assets	$ 0.08	$ 0.07	$ 0.08	$ 0.06
Interest expense (b)	$ 0.45	$ 0.53	$ 0.46	$ 0.57
Interest Expense ($ in thousands):				
Interest expense	$ 42,258	$ 38,855	$ 118,335	$ 113,011
Interest rate derivatives – realized (gains) losses	221	(1,097)	(184)	(2,453)
Interest rate derivatives – unrealized (gains) losses	6,210	3,093	5,889	5,333
Total interest expense	$ 48,689	$ 40,851	$ 124,040	$ 115,891
Net Wells Drilled	181	130	420	326
Net Producing Wells as of the End of Period	7,838	5,710	7,838	5,710

(a) Current Period includes a pre-tax benefit of $6.8 million, or $0.03 per mcfe, from prior period severance tax credits.
(b) Includes the effects of realized gains or (losses) from hedging, but does not include the effects of unrealized gains or (losses) from hedging.

Chesapeake is the fifth largest independent producer of natural gas in the U.S. and owns interests in approximately 19,000 (7,838 net) producing oil and gas wells. Our primary operating area is the Mid-Continent region of the United States, which includes Oklahoma, western Arkansas, southwestern Kansas and the Texas Panhandle, and we are building significant operating areas in the Permian Basin of western Texas and eastern New

Mexico, in the Ark-La-Tex area of eastern Texas and northern Louisiana and in the South Texas and Texas Gulf Coast regions.

Oil and natural gas production for the Current Quarter was 94.2 bcfe, an increase of 23.2 bcfe, or 33%, over the 71.0 bcfe produced in the Prior Quarter. The 23.2 bcfe increase in production consisted of approximately 9.3 bcfe generated from organic growth through drilling and approximately 13.9 bcfe generated from acquisitions.

We have increased our production for 15 consecutive years and the Current Quarter was Chesapeake's 13th consecutive quarter of sequential production growth. During these 13 quarters, Chesapeake's production has increased 141%, for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 31%.

In addition to increased oil and natural gas production, the prices we received were higher in the Current Quarter than in the Prior Quarter. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $5.13 per mcfe in the Current Quarter compared to $4.86 per mcfe in the Prior Quarter. The increase in prices resulted in an increase in revenue of $25.4 million, and increased production resulted in an increase in revenue of $113.1 million, for a total increase in revenue of $138.5 million (excluding the effect of unrealized gains or losses on derivatives).

Chesapeake began the Current Quarter with estimated proved reserves of 3,805 bcfe and ended the quarter with 4,455 bcfe. Taking into account production of 94.2 bcfe, reserve replacement during the Current Quarter was 744 bcfe, or 789%, at a finding and acquisition cost of $756 million, or $1.02 per mcfe (excluding $66 million of leasehold and seismic purchases, $187 million of acquisition costs allocated to unevaluated leasehold, $177 million of deferred tax step-up incurred in connection with certain corporate acquisitions and $17 million of other additions. Reserve replacement through the drillbit was 364 bcfe (including 91 bcfe from performance revisions and 18 bcfe from oil and natural gas price increases), or 49% of the total increase, and reserve replacement through acquisitions was 380 bcfe, or 51% of the total increase.

Chesapeake drilled 182 (143 net) operated wells and participated in another 292 (38 net) wells operated by other companies during the Current Quarter. Chesapeake's drilling costs were $224 million for operated wells and $68 million for non-operated wells. The company's success rate was 98% for operated wells and 96% for non-operated wells. Our investment in leasehold and 3-D seismic data totaled $66 million and our acquisition expenditures totaled $650 million during the Current Quarter.

During the Current Period, we received net proceeds of $1,512 million through issuances of $650 million of common equity, $313 million of preferred equity (4.125% convertible preferred stock), $300 million principal amount of 7.5% Senior Notes due 2014 and $300 million principal amount of 7.0% Senior Notes due 2014. As of September 30, 2004, the company's total debt as a percentage of total capitalization (total capitalization is the sum of total debt and stockholders' equity) was 49%, compared to 56% as of September 30, 2003. Additionally, through debt repurchases and exchanges completed in the second half of 2003 and the Current Period, we have extended the average maturity of our long-term debt to over nine years and have lowered our average interest rate to 7.6%.

During the Current Quarter, holders of our 6.75% preferred stock converted 283,600 shares into 1,841,556 shares of common stock (at a conversion price of $7.70 per share). During November 2004, we expect to cause conversion of the remaining 6.75% preferred stock into 17,624,657 shares of common stock.

Our revenues, operating results, profitability and future growth depend on our ability to find, develop and acquire oil and gas reserves that are economically recoverable based on prevailing prices for natural gas and oil. The company favors gas over oil, strives to establish regional dominance in our operating areas, grows through a combination of drilling and acquisitions and manages price risk through opportunistic oil and natural gas hedging.

We intend to continue to focus on improving the strength of our balance sheet. The company's revolving bank credit facility is currently rated as investment grade by one rating agency. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt in the future.

Liquidity and Capital Resources

Sources of Liquidity

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for large acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our budgeted drilling capital expenditures in the fourth quarter of 2004 and in 2005. Our budget for drilling, land and seismic activities is currently $300 million to $325 million for the 2004 fourth quarter and $1.2 billion to $1.3 billion for 2005. While we believe this level of exploration and development will be sufficient to increase our reserves in the fourth quarter of 2004 and in 2005 and achieve our target of year-over-year production growth of 33% in 2004 and 14% in 2005, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which is largely discretionary. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes.

Cash flows from operating activities, excluding changes in assets and liabilities, were $995.1 million in the Current Period, compared to $641.5 million in the Prior Period. The $353.6 million increase in the Current Period was due primarily to higher realized prices and higher volumes of oil and gas production. We expect that production volumes in the 2004 fourth quarter and full-year 2005 will be higher than in the 2003 fourth quarter and full-year 2004, respectively, and that cash flows from operating activities in the 2004 fourth quarter and full-year 2005 will be higher than in the 2003 fourth quarter and full-year 2004, respectively. While a precipitous decline in oil and gas prices would significantly affect the amount of cash flow that would be generated from operations, we have 96% of our expected oil production in the 2004 fourth quarter hedged at an average NYMEX price of $30.10 per barrel of oil and 86% of our expected natural gas production in the 2004 fourth quarter hedged at an average NYMEX price of $5.77 per mcf. In addition, we have 30% of our expected oil production in 2005 hedged at an average NYMEX price of $40.20 per barrel of oil and 35% of our expected natural gas production in 2005 hedged at an average NYMEX price of $5.96 per mcf. This level of hedging provides certainty of the cash flow we will receive for a substantial portion of our remaining 2004 production and approximately one-third of our 2005 production. Depending on changes in oil and gas futures markets and management's view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. To mitigate the liquidity impact of those collateral requirements, we have negotiated caps on the amount of collateral that we might be required to post with five of our counterparties. All of our existing commodity hedges that are not under our secured hedging facility are with these counterparties and the maximum amount of collateral that we would be required to post with these counterparties is capped at $250 million.

Another source of liquidity is our $600 million revolving bank credit facility (with current bank commitments of $500 million) which matures in June 2008. We had $152 million and $253 million of outstanding borrowings under the bank credit facility as of September 30, 2004 and November 4, 2004, respectively. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $1,413 million and repaid $1,261 million in the Current Period and borrowed $485 million and repaid $413 million in the Prior Period under the bank credit facility. We plan to increase the commitments under the revolving bank credit facility to $600 million in November 2004.

We believe that our available cash, cash flows from operating activities and funds available under our bank credit facility will be sufficient to fund our operating, interest and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future.

The public and institutional markets have been our principal source of capital to finance large acquisitions. We have issued debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future for acquisitions. Nevertheless, we caution you that ready access to capital on reasonable terms and the availability of desirable acquisition targets at attractive prices are subject to many uncertainties, as explained under "Risk Factors" in Item 1—Business of our Form 10-K for the year ended December 31, 2003. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30,			
	2004		2003	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$ 313.3	$ 304.9	$ 230.0	$ 222.9
Common stock	650.0	624.2	186.3	177.4
Unsecured senior notes guaranteed by subsidiaries	600.0	582.9	300.0	290.9
Total	$ 1,563.3	$ 1,512.0	$ 716.3	$ 691.2

We filed a $600 million "universal shelf" registration statement with the Securities and Exchange Commission on September 28, 2004. Securities issued under this shelf may be in the form of common stock, preferred stock, depository shares representing fractional shares of preferred stock or debt securities of Chesapeake. A prospectus supplement will be prepared at the time of a debt or equity offering and will contain specific information about the security issued and the use of proceeds. We have not issued any securities under this shelf registration.

In June 2004, we amended our certificate of incorporation to increase authorized capital stock. The number of authorized shares of our common stock increased from 350 million to 500 million and the number of authorized shares of our preferred stock increased from 10 million to 20 million.

We paid common stock dividends of $26.9 million and $19.7 million in the Current Period and in the Prior Period, respectively, and we paid dividends of $30.3 million and $14.9 million on our preferred stock in the Current Period and in the Prior Period, respectively. We received $9.0 million and $7.8 million from the exercise of employee and director stock options in the Current Period and in the Prior Period, respectively. We used $2.1 million to purchase treasury stock in the Prior Period to fund our matching contributions to the 401(k) Make-Up Plan.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set off exist increased by $89.3 million in the Current Period. All disbursement accounts are funded the next business day using available cash on hand or draws on our credit facility.

Historically, we have used significant amounts of funds to purchase and retire our obligations under outstanding Senior Notes. In March 2004, we retired $42.1 million of our 7.875% Senior Notes at maturity and we redeemed the remaining $4.3 million of our 8.5% Senior Notes for $4.5 million, including a redemption premium of $0.2 million. We paid $4.6 million of cash in lieu of issuing fractional notes on our exchange of $458.5 million of 8.125% Senior Notes for $72.8 million of 7.75% Senior Notes and $433.5 million of 6.875% Senior Notes in January 2004. We paid $6.0 million in transaction costs related to this exchange.

Cash used in investing activities increased to $2,668.2 million during the Current Period, compared to $1,600.8 million during the Prior Period. The following table shows our capital expenditures during these periods ($ in millions):

	Nine Months Ended September 30,	
	2004	2003
Acquisitions of oil and gas companies, proved properties and unproved properties, net of cash acquired	$ 1,657.5	$ 1,023.0
Exploration and development of oil and gas properties	888.3	518.8
Additions to building and other fixed assets	77.1	54.4
Divestitures of oil and gas properties	(0.3)	(21.2)
Cash paid for investments and other assets	26.7	25.9
Additions to drilling rig equipment	19.3	0.1
Other	(0.4)	(0.2)
Total	$ 2,668.2	$ 1,600.8

Our accounts receivable are primarily from purchasers of oil and natural gas ($238.1 million as of September 30, 2004) and exploration and production companies which own interests in properties we operate ($60.1 million as of September 30, 2004). This 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.

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.

Investing and Financing Transactions

The following describes significant investing and financing transactions that we completed in the Current Period:

Investing Transactions:

Third Quarter 2004

- Acquired Bravo Natural Resources, Inc. (Mid-Continent oil and gas assets) and Mid-Continent gas properties from Tilford Pinson Exploration, LLC. for cash consideration of approximately $355 million.

- Acquired South Texas oil and gas assets from Legend Natural Gas, LLP for cash consideration of approximately $215 million.

- Acquired Mid-Continent oil and gas assets in various smaller transactions for total cash consideration of approximately $90 million.

Second Quarter 2004

- Acquired Greystone Petroleum, LLC (natural gas assets in Ark-La-Tex region of northern Louisiana) for cash consideration of approximately $425 million.

- Acquired Permian Resources Holdings, Inc. (Permian Basin oil and gas assets) for cash consideration of approximately $69 million.

- Acquired Mid-Continent oil and gas assets in three smaller transactions for total cash consideration of approximately $31 million.

First Quarter 2004

- Acquired Concho Resources Inc. (Permian Basin and Mid-Continent oil and gas assets) for cash consideration of approximately $420 million, of which $10 million was paid in 2003. We also paid $12 million in employee severance and other transaction costs at closing.

- Acquired Texas Gulf Coast properties for cash consideration of approximately $65 million, of which $3.3 million was paid in 2003.

Financing Transactions:

Third Quarter 2004

- Completed a public offering of 23 million shares of common stock at $14.75 per share. Net proceeds of approximately $326.2 million were used to finance a portion of the Bravo, Legend and Tilford Pinson acquisitions and to repay amounts outstanding under our bank credit facility.

- Completed a private placement of $300 million 7.0% Senior Notes due 2014. Net proceeds of approximately $294.3 million were used to finance a portion of the Bravo, Legend and Tilford Pinson acquisitions and to repay amounts outstanding under our bank credit facility.

Second Quarter 2004

- Completed a private placement of $300 million 7.5% Senior Notes due 2014. Net proceeds of approximately $288.6 million were used to finance a portion of the Greystone acquisition completed in June 2004.

- Issued an additional 38,250 shares of 4.125% convertible preferred stock upon exercise of an option we granted to the purchasers in a March 2004 private placement for net proceeds of $37.2 million.

First Quarter 2004

- Completed a public offering of 23 million shares of common stock at $13.51 per share. Net proceeds of approximately $298.1 million were used to finance a portion of the acquisitions completed in January 2004.

- Issued 275,000 shares of 4.125% convertible preferred stock at $1,000 per share in a private placement. Net proceeds of approximately $267.7 million were used to pay outstanding borrowings under our revolving bank credit facility which were incurred as a result of acquisitions completed in the first quarter of 2004.

- Completed a public exchange offer in which we retired $458.5 million of our 8.125% Senior Notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% Senior Notes due 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% Senior Notes due 2016 and $4.1 million of accrued interest.

- Issued an additional $37.0 million of our 6.875% Senior Notes due 2016 and $0.5 million of accrued interest in exchange for $24.3 million of our 8.125% Senior Notes due 2011 and $0.7 million of accrued interest and $9.1 million of our 7.75% Senior Notes due 2015 and $0.1 million of accrued interest in four private exchange transactions.

- Paid $4.5 million (including a premium of $0.2 million) to redeem $4.3 million of 8.5% Senior Notes due 2012 representing all outstanding notes which were not tendered pursuant to a cash tender offer completed in December 2003.

- Paid $42.1 million representing the balance outstanding on our 7.875% Senior Notes that matured on March 15, 2004.

Contractual Obligations

We have a $600 million revolving bank credit facility (with current bank commitments of $500 million) which matures in June 2008. As of September 30, 2004, we had $152.0 million of outstanding borrowings under this facility and utilized $73.9 million of the facility for various letters of credit. The outstanding borrowings under this facility and the letters of credit were $253 million and $148 million, respectively, as of November 4, 2004. Borrowings under the facility are collateralized by certain producing oil and gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to an annual commitment fee that also varies according to our senior unsecured long-term debt ratings. Currently the annual commitment fee rate is 0.30%. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. We plan to increase the commitments under the revolving bank credit facility to $600 million in November 2004.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, sell properties, purchase or redeem our capital stock, make investments or loans and create liens. In addition, the agreement requires us to maintain a current ratio (as defined) of at least 1 to 1 and a fixed charge coverage ratio (as defined) of at least 2.5 to 1. As of September 30, 2004, our current ratio was 1.13 to 1 and our fixed charge coverage ratio was 5.19 to 1. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million or more, would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $35.0 million.

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 exceed certain levels. As of September 30, 2004, we were required to post $72 million of collateral in the form of letters of credit with respect to such derivative transactions. These collateral requirements were $146 million as of November 4, 2004. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and fluctuations in natural gas and oil prices and interest rates. We currently have arrangements with five of our counterparties which limit the amount of collateral that we would be required to post with a counterparty to $50 million each.

In May 2004, we entered into a secured natural gas hedging facility with a nationally recognized counterparty. Under this hedging facility, which matures in May 2009, we can enter into cash-settled natural gas commodity transactions, valued by the counterparty, for up to $600 million. Outstanding transactions under the facility are collateralized by certain oil and gas properties, exclusive of the oil and gas properties that collateralize our revolving bank credit facility. The hedging facility is subject to an annual fee of 0.30% of the maximum total capacity and a 1.0% exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of September 30, 2004, the fair market value of the natural gas hedging transactions related to the hedging facility was ($7.2) million.

The hedging facility contains the standard representations and default provisions that are typical of such agreements. The agreement also contains various restrictive provisions which govern the aggregate gas production volumes that we are permitted to hedge under all of our agreements at any one time. The hedging facility is guaranteed by Chesapeake and all our subsidiaries.

In addition to outstanding revolving bank credit facility borrowings discussed above, as of September 30, 2004, our long-term debt included senior notes, as listed below ($ in thousands):

8.375% senior notes due 2008	$ 209,815
8.125% senior notes due 2011	245,407
9.0% senior notes due 2012	300,000
7.5% senior notes due 2013	363,823
7.0% senior notes due 2014	300,000
7.5% senior notes due 2014	300,000
7.75% senior notes due 2015	300,408
6.875% senior notes due 2016	670,437
Discount on senior notes	(80,661)
Premium for interest rate swaps	1,196
	$2,610,425

No scheduled principal payments are required on any of the senior notes until 2008, when $209.8 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. Debt ratings for our secured bank credit facility are BB+ by Standard & Poor's Ratings Services and BBB- 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 guarantee the notes including Chesapeake Energy Marketing, Inc., Mayfield Processing, LLC and MidCon Compression, L.P., for which the guarantee became effective September 21, 2004. The indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures contain covenants limiting our ability and our 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; 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 September 30, 2004, we estimate that secured bank indebtedness of approximately $1.64 billion could have been incurred under the most restrictive indenture covenant.

Results of Operations — Three Months Ended September 30, 2004 vs. September 30, 2003

General. For the Current Quarter, Chesapeake had net income of $96.9 million, or $0.29 per diluted common share, on total revenues of $629.8 million. This compares to net income of $87.9 million, or $0.33 per diluted common share, on total revenues of $454.5 million during the Prior Quarter. The Current Quarter net income includes, on a pre-tax basis, $38.7 million in net unrealized losses on oil and gas and interest rate derivatives. The Prior Quarter net income included, on a pre-tax basis, $2.5 million in net unrealized losses on oil and gas and interest rate derivatives.

Oil and Gas Sales. During the Current Quarter, oil and gas sales were $450.9 million compared to $345.6 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 94.2 bcfe at a weighted average price of

$5.13 per mcfe, compared to 71.0 bcfe produced in the Prior Quarter at a weighted average price of $4.86 per mcfe (weighted average prices for both quarters exclude the effect of unrealized gains or (losses) on derivatives of ($32.5) million and $0.6 million in the Current Quarter and Prior Quarter, respectively). The increase in prices in the Current Quarter resulted in an increase in revenue of $25.4 million and increased production resulted in a $113.1 million increase, for a total increase in revenues of $138.5 million (excluding unrealized gains or losses on oil and gas derivatives). The increase in production from the Prior Quarter to the Current Quarter is due to the combination of production growth generated from drilling as well as acquisitions completed in 2003 and in 2004.

The change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $8.3 million and $7.8 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $1.8 million and $1.7 million, respectively, without considering the effect of derivative activities.

For the Current Quarter, we realized an average price per barrel of oil of $29.15, compared to $26.20 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $5.17 and $4.92 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our oil and gas derivatives resulted in a net decrease in oil and gas revenues of $38.0 million or $0.40 per mcfe in the Current Quarter and a net increase of $17.7 million or $0.25 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 September 30,			
	2004		2003	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	68,254	73%	62,909	89%
South Texas and Texas Gulf Coast	12,438	13	4,987	7
Permian Basin	7,967	8	2,063	3
Ark-La-Tex	4,890	5	279	—
Williston Basin and Other	674	1	742	1
Total Production	94,223	100%	70,980	100%

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

Oil and Gas Marketing Sales and Expenses. Chesapeake realized $178.9 million in oil and gas marketing sales in the Current Quarter, with corresponding oil and gas marketing expenses of $175.4 million, for a net margin of $3.5 million. Marketing activities are substantially for third parties that are owners in Chesapeake operated wells. This compares to sales of $109.0 million, expenses of $105.8 million and a net margin of $3.2 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and gas marketing sales volumes and an increase in oil and gas prices.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $54.1 million in the Current Quarter compared to $35.9 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.57 per mcfe in the Current Quarter compared to $0.51 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher field service costs. We expect that production expenses per mcfe during the remainder of 2004 will range from $0.57 to $0.62.

Production Taxes. Production taxes were $30.9 million and $21.6 million in the Current Quarter and the Prior Quarter, respectively. On a unit-of-production basis, production taxes were $0.33 per mcfe in the Current Quarter compared to $0.30 per mcfe in the Prior Quarter. The increase in production taxes in the Current Quarter is due primarily to approximately 23.2 bcfe of increased production. 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 per mcfe to range from $0.40 to $0.44 during the remainder of 2004 based on an assumption that oil and natural gas wellhead prices will range from $6.00 to $7.00 per mcfe.

General and Administrative Expenses (excluding stock based compensation). General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties, were $8.4 million, or $0.09 per mcfe, in the Current Quarter and $4.7 million, or $0.07 per mcfe, in the Prior Quarter. The increase in the Current Quarter of $3.7 million is the result of additional costs associated with the company's growth. This growth has resulted in an increase in the number of employees and related compensation, facilities and other costs. We anticipate that general and administrative expenses for the remainder of 2004 will be between $0.10 and $0.11 per mcfe produced, which is approximately the same level as the Current Quarter.

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $12.0 million and $9.9 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our oil and gas exploration and development efforts.

Stock Based Compensation. Stock based compensation was $0.6 million in the Current Quarter and $0.1 million in the Prior Quarter. During the Current Quarter, 1.5 million shares of restricted stock were issued to employees. The cost of all outstanding restricted shares is amortized over a four-year period which resulted in the recognition of $0.4 million of stock based compensation costs during the Current Quarter. Of this amount, $0.3 million was reflected as stock based compensation expense (a sub-category of general and administrative costs) in the condensed consolidated statements of operations, and the remaining $0.1 million was capitalized to oil and gas properties. Chesapeake's stock based compensation did not include restricted stock awards prior to 2004. Additionally, we recognized $0.3 million and $0.1 million in stock based compensation expense in the Current Quarter and Prior Quarter, respectively, as a result of modifications made to previously issued stock options. Stock based compensation was $0.01 per mcfe for the Current Quarter and $0.00 per mcfe for the Prior Quarter. We anticipate that stock based compensation expense for the remainder of 2004 will be between $0.02 and $0.04 per mcfe produced.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $153.6 million and $97.9 million during the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.63 and $1.38 in the Current Quarter and in the Prior Quarter, respectively. The $0.25 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2004 to be between $1.65 and $1.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $7.7 million in the Current Quarter, compared to $4.8 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation costs resulting from the acquisition of a processing plant, various gathering facilities, construction of new buildings at our corporate headquarters and the purchase of additional information technology equipment and software in 2003 and the Current Period. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 39 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to fifteen years. To the extent 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 2004.

Provision for Legal Settlements. During the Prior Quarter, we accrued and subsequently paid into the court $0.7 million related to a legal proceeding brought against us by certain royalty owners. The case was subsequently dismissed pursuant to a settlement agreement effective December 31, 2003. The settlement is described in note 4 to the consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2003.

Interest and Other Income. Interest and other income was $0.9 million in the Current Quarter compared to a loss of $0.2 million in the Prior Quarter. The Current Quarter income consisted of $0.6 million of interest income, $0.3 million related to losses of equity investees, and $0.6 million of miscellaneous income. The Prior Quarter income consisted of $0.2 million of interest income, $0.3 million related to losses of equity investees, and $0.1 million of miscellaneous losses.

Interest Expense. Interest expense increased from $40.9 million in the Prior Quarter to $48.7 million in the Current Quarter. The increase in interest expense was partially due to an increase in the average long-term borrowings under our senior notes of $553 million in the Current Quarter in comparison to the Prior Quarter, as well as an increase in amortization of bond discount from $0.4 million in the Prior Quarter to $1.2 million in the Current Quarter. This increase in interest expense was partially offset by a $7.1 million increase in the capitalized interest from $3.4 million in the Prior Quarter to $10.5 in the Current Quarter. Interest is capitalized on significant investments in unproved properties that are not currently being depreciated, depleted or amortized and on which exploration activities are in progress based on the weighted average effective interest rate on our outstanding borrowings. In addition, the increase in interest expense in the Current Quarter was also due to an increase in unrealized losses on interest rate derivatives from $3.1 million in the Prior Quarter to $6.2 million in the Current Quarter. Interest expense also increased due to a decline in realized gains related to interest rate derivatives. Realized gains on interest rate derivatives were $1.1 million in the Prior Quarter and realized losses on interest rate derivatives were $0.2 million in the Current Quarter. In total, interest expense increased by $4.4 million in the Current Quarter compared to the Prior Quarter with respect to interest rate derivatives.

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 value 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. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears below in Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized (gains) losses on derivatives, was $0.45 per mcfe in the Current Quarter compared to $0.53 per mcfe in the Prior Quarter. We expect interest expense for the remainder of 2004 to be between $0.45 and $0.49 per mcfe produced (before considering the effects of derivatives).

Income Tax Expense. Chesapeake recorded income tax expense of $54.5 million in the Current Quarter, compared to income tax expense of $53.8 million in the Prior Quarter. During the Current Quarter, our effective income tax rate decreased to 36% compared to 38% in the Prior Quarter to reflect our assessment of the impact state income taxes have on our overall effective rates. The Current Quarter income tax expense was completely deferred.

Results of Operations — Nine Months Ended September 30, 2004 vs. September 30, 2003

General. For the Current Period, Chesapeake had net income of $306.6 million, or $0.98 per diluted common share, on total revenues of $1,767.2 million. This compares to net income of $243.6 million, or $0.96 per diluted common share, on total revenues of $1,260.7 million during the Prior Period. The Current Period net income includes, on a pre-tax basis, a $6.9 million loss on repurchases or exchanges of debt and $72.5 million in net unrealized losses on oil and gas and interest rate derivatives. The Prior Period net income included, on a pre-tax basis, $28.3 million in net unrealized gains on oil and gas and interest rate derivatives.

Oil and Gas Sales. During the Current Period, oil and gas sales were $1,270.4 million compared to $951.1 million in the Prior Period. In the Current Period, Chesapeake produced 259.7 bcfe at a weighted average price of $5.15 per mcfe, compared to 195.1 bcfe produced in the Prior Period at a weighted average price of $4.70 per mcfe (weighted average prices for both periods exclude the effect of unrealized gains or (losses) on derivatives of ($66.6) million and $33.7 million in the Current Period and Prior Period, respectively). The increase in prices in the Current Period resulted in an increase in revenue of $116.9 million and increased production resulted in a $302.7 million increase, for a total increase in revenues of $419.6 million (excluding unrealized gains or losses on oil and gas derivatives). The increase in production from the Prior Period to the Current Period is due to the combination of production growth generated from drilling as well as acquisitions completed in 2003 and the Current Period.

The change in oil and gas prices has a significant impact on our oil and gas revenues and cash flows. Assuming the Current Period production levels, a change of $0.10 per mcf of gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $23.0 million and $21.8 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $5.0 million and $4.7 million, respectively, without considering the effect of derivative activities.

For the Current Period, we realized an average price per barrel of oil of $28.20, compared to $26.54 in the Prior Period (weighted average prices for both periods discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $5.21 and $4.74 in the Current Period and Prior Period, respectively. Realized gains or losses from our oil and gas derivatives resulted in a net decrease in oil and gas revenues of $67.6 million or $0.26 per mcfe in the Current Period and a net decrease of $74.0 million or $0.38 per mcfe in the Prior Period.

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

	For the Nine Months Ended September 30,			
	2004		2003	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	194,897	75%	170,898	88%
South Texas and Texas Gulf Coast	34,514	13	15,035	8
Permian Basin	21,391	8	6,049	3
Ark-La-Tex	6,877	3	836	—
Williston Basin and Other	1,980	1	2,248	1
Total Production	259,659	100%	195,066	100%

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

Oil and Gas Marketing Sales and Expenses. Chesapeake realized $496.8 million in oil and gas marketing sales in the Current Period, with corresponding oil and gas marketing expenses of $486.2 million, for a net margin of $10.6 million. Marketing activities are substantially for third parties that are owners in Chesapeake operated wells. This compares to sales of $309.6 million, expenses of $302.1 million and a net margin of $7.5 million in the Prior Period. In the Current Period, Chesapeake realized an increase in oil and gas marketing sales volumes and an increase in oil and gas prices.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $148.5 million in the Current Period compared to $101.7 million in the Prior Period. On a unit-of-production basis, production expenses were $0.57 per mcfe in the Current Period compared to $0.52 per mcfe in the Prior Period. The increase in the Current Period was primarily due to higher field service costs. We expect that production expenses per mcfe during the remainder of 2004 will range from $0.57 to $0.62.

Production Taxes. Production taxes were $68.6 million and $57.3 million in the Current Period and the Prior Period, respectively. On a unit-of-production basis, production taxes were $0.26 per mcfe in the Current Period compared to $0.29 per mcfe in the Prior Period. Included in the Current Period is a credit of $6.8 million, or $0.03 per mcfe, related to certain Oklahoma severance tax abatements for the period July 2003 through December 2003. In April 2004, the Oklahoma Tax Commission concluded that a pre-determined oil and gas price cap for 2003 sales had not been exceeded (on a statewide basis) and notified the company that it was eligible to receive certain severance tax abatements for the period from July 1, 2003 through June 30, 2004. The company had previously estimated that the average oil and gas sales prices in Oklahoma (on a statewide basis) could exceed the price cap, and did not reflect the benefit from these potential severance tax abatements until the first quarter of 2004. 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 per mcfe to range from $0.40 to $0.44 during the remainder of 2004 based on an assumption that oil and natural gas wellhead prices will range from $6.00 to $7.00 per mcfe.

General and Administrative Expenses (excluding stock based compensation). General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and gas properties, were $23.9 million in the Current Period, or $0.09 per mcfe, and $15.7 million in the Prior Period, or $0.08 per mcfe. The increase in the Current Period of $8.2 million is the result of additional costs associated with the company's growth. This growth has resulted in an increase in the number of employees and related compensation, facilities and other costs. We anticipate that general and administrative expenses for the remainder of 2004 will be between $0.10 and $0.11 per mcfe produced, which is approximately the same level as the Current Period.

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 $35.3 million and $25.7 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our oil and gas exploration and development efforts.

Stock Based Compensation. Stock based compensation was $3.1 million in the Current Period and $0.5 million in the Prior Period. During the Current Period, 2.7 million shares of restricted stock were issued to employees. The cost of all outstanding restricted shares is amortized over a four-year period which resulted in the recognition of $3.9 million of stock based compensation costs during the Current Period. Of this amount, $2.6 million was reflected as stock based compensation expense (a sub-category of general and administrative costs) in the condensed consolidated statements of operations, and the remaining $1.3 million was capitalized to oil and gas properties. Chesapeake's stock based compensation did not include restricted stock awards prior to 2004. Additionally, we recognized $0.5 million in stock based compensation expense in the Current Period and Prior Period, respectively, as a result of modifications made to previously issued stock options. Stock based compensation was $0.01 per mcfe for the Current Period and $0.00 per mcfe for the Prior Period. We anticipate that stock based compensation expense for the remainder of 2004 to be between $0.02 and $0.04 per mcfe produced.

Provision for Legal Settlements. During the Prior Period, we accrued and subsequently paid into the court $1.0 million related to a legal proceeding brought against us by certain royalty owners. The case was subsequently dismissed pursuant to a settlement agreement effective December 31, 2003. The settlement is described in note 4 to the consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2003.

Oil and Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and gas properties was $410.2 million and $266.1 million during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs, and the related underlying reserves in the periods presented, was $1.58 and $1.36 in the Current Period and in the Prior Period, respectively. The $0.22 increase in the average rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2004 to be between $1.65 and $1.70 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $20.2 million in the Current Period, compared to $12.6 million in the Prior Period. The increase in the Current Period was primarily the result of higher depreciation costs resulting from the acquisition of a processing plant, various gathering facilities, construction of new buildings at our corporate headquarters and the purchase of additional information technology equipment and software in 2003 and the Current Period. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 39 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to fifteen years. To the extent 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 2004.

Interest and Other Income. Interest and other income was $3.6 million and $1.4 million in the Current Period and the Prior Period, respectively. The Current Period income consisted of $1.5 million of interest income, $0.8 million of income related to earnings of equity investees, and $1.3 million of miscellaneous income. The Prior Period income consisted of $0.9 million of interest income, $0.3 million related to losses of equity investees, and $0.8 million of miscellaneous income.

Interest Expense. Interest expense increased from $115.9 million in the Prior Period to $124.0 million in the Current Period. The increase in interest expense was partially due to an increase in average long-term borrowings under our senior notes of $413 million in the Current Period in comparison to the Prior Period, as well as an increase in amortization of bond discount from $1.1 million in the Prior Period to $3.3 million in the Current Period. This increase in interest expense was partially offset by an increase in capitalized interest of $14.4 million from $8.8 million in the Prior Period to $23.2 million in the Current Period. Interest is capitalized on significant investments in unproved properties that are not currently being depreciated, depleted or amortized and on which exploration activities are in progress and is based on the weighted average effective interest rate on our outstanding borrowings. In addition, the increase in interest expense in the Current Period was also due to an increase in unrealized losses on interest rate derivatives from $5.3 million in the Prior Period to $5.9 million in the Current Period. Interest expense also increased due to a decline in realized gains related to interest rate derivatives. Realized gains on interest rate derivatives were $2.5 million in the Prior Period and were $0.2 million in the Current Period. In total, interest expense increased by $2.9 million in the Current Period compared to the Prior Period with respect to interest rate derivatives.

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 value 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. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears below in Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized (gains) losses on derivatives, was $0.46 per mcfe in the Current Period compared to $0.57 per mcfe in the Prior Period. We expect interest expense for the remainder of 2004 to be between $0.45 and $0.49 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Repurchases or Exchanges of Debt. In the Current Period, we completed a public exchange offer in which we retired $458.5 million of our 8.125% Senior Notes due 2011 and $10.8 million of accrued interest and issued $72.8 million of our 7.75% Senior Notes due 2015 and $2.8 million of accrued interest and $433.5 million of our 6.875% Senior Notes due 2016 and $4.1 million of accrued interest. In connection with this exchange, we recorded a pre-tax loss of $6.0 million, consisting of $5.7 million of underwriting fees and $0.3 million in other transaction costs. During the Current Period, we redeemed $4.3 million of our 8.5% Senior Notes due 2012 for a total consideration of $4.5 million. In connection with this transaction, we recorded a pre-tax loss of $0.9 million, consisting of $0.2 million of redemption premium, $0.1 million of unamortized debt issue costs and discount on senior notes and $0.6 million carried as a discount on the 8.5% Senior Notes based on the hedging relationship between the notes and a swaption.

Income Tax Expense. Chesapeake recorded income tax expense of $172.5 million in the Current Period, compared to income tax expense of $147.8 million in the Prior Period. During the Current Period, our effective income tax rate decreased to 36% compared to 38% in the Prior Period to reflect our assessment of the impact state income taxes have on our overall effective rates. The Current Period income tax expense was completely deferred.

Cumulative Effect of Accounting Change. Effective January 1, 2003, Chesapeake adopted SFAS No. 143, *Accounting For Asset Retirement Obligations*. Upon adoption of SFAS 143 in the Prior Period, we recorded the discounted fair value of our expected future obligations of $30.5 million, a cumulative effect of 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.

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, 2003, 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 sets forth 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. Consistent with oil and gas accounting and industry practice, Chesapeake classifies the cost of oil and gas mineral rights as property and equipment and not as intangible assets.

In September 2004, the FASB finalized FASB Staff Position, FSP SFAS 142-2, *Application of FASB Statement No. 142 to Oil and Gas Producing Entities*. The FSP clarifies that an exception in SFAS 142 includes the balance sheet classification and disclosures for drilling and mineral rights of oil and gas producing entities. The FASB staff acknowledges that the existing accounting framework for oil and gas producers is based on the level of established reserves, not whether an asset is tangible or intangible. The FSP confirms Chesapeake's historical treatment of these costs.

Recently Issued Accounting Standards

In September 2004, the Securities and Exchange Commission issued Staff Accounting Bulletin 106 which summarizes the views of the staff regarding the application of SFAS 143, *Accounting for Asset Retirement Obligations*, by oil and gas producing companies following the full cost accounting method. This bulletin will be effective in the Fourth Quarter of 2004. Implementation of this pronouncement is not expected to have a material effect on our financial statements.

In September 2004, the Emerging Issues Task Force issued EITF No. 04-8, *The Effect of Contingently Convertible Instruments on Diluted Earnings per Share*. EITF No. 04-8 provides new guidance on when the dilutive effect of contingently convertible securities with a market price trigger should be included in diluted EPS. The guidance in EITF No. 04-8 is effective for all periods ending after December 15, 2004 and Chesapeake will comply by retrospectively restating previously reported EPS. The effect of this pronouncement on diluted EPS is more fully described in Note 4 to the accompanying interim condensed consolidated financial statements.

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 expenses, projections of future oil and gas prices, planned capital expenditures for drilling, leasehold acquisitions and seismic data, and statements concerning anticipated cash flow and liquidity, our business strategy and other plans and objectives for future operations. In addition, statements concerning the fair value of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Supplemental Risk Factors" in our prospectus dated September 10, 2004 filed with the Securities and Exchange Commission on September 10, 2004. They include:

- the volatility of oil and gas prices;
- adverse effects our substantial indebtedness and preferred stock obligations could have on our operations and future growth and on our ability to make debt service and preferred stock dividend payments as they become due;
- our ability to compete effectively against strong independent oil and gas companies and majors;
- financial losses and significant collateral requirements as a result of our commodity price and interest rate risk 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 and companies;
- our ability to replace reserves;
- the availability of capital;
- writedowns of oil and gas carrying values if commodity prices decline;
- environmental and other claims in excess of insured amounts resulting from drilling and production operations; and
- the loss of key personnel.

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

ITEM 3. ***Quantitative and Qualitative Disclosures About Market Risk***

Oil and Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2004, our oil and gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. 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, Chesapeake receives a fixed price for the hedged commodity and pays 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 put 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.

- For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking in the value of a 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 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.

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. Changes in the value of cap-swaps and the counter-swaps are recorded as adjustments to oil and gas sales.

In accordance with FASB Interpretation No. 39, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets, to the extent that a legal right of setoff exists.

Gains or losses from derivative transactions are reflected as adjustments to oil and gas sales on the condensed consolidated statements 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 were ($32.5) million, $0.6 million, ($66.6) million and $33.7 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. These amounts include gains (losses) on ineffectiveness discussed below.

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 attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and gas sales as unrealized gains (losses). We recorded a gain (loss) on ineffectiveness of ($1.8) million, $5.3 million, ($17.0) million and $5.8 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

As of September 30, 2004, we had the following open oil and gas derivative instruments designed to hedge a portion of our oil and gas production for periods after September 2004:

	Volume mmbtu/bbls	Weighted-Average Fixed Price to be Received (Paid)	Weighted-Average Put Fixed Price	Weighted-Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Premiums Received	Fair Value at September 30, 2004 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
2004	61,560,000	5.83	—	—	—	Yes	$ —	$ (47,619)
2005	61,045,000	6.11	—	—	—	Yes	—	(71,441)
Basis Protection Swaps:								
2004	39,560,000	—	—	—	(0.17)	No	—	14,284
2005	175,200,000	—	—	—	(0.25)	No	—	30,226
2006	113,150,000	—	—	—	(0.30)	No	—	10,990
2007	107,675,000	—	—	—	(0.26)	No	—	14,972
2008	107,970,000	—	—	—	(0.25)	No	—	13,549
2009	80,300,000	—	—	—	(0.28)	No	—	7,325
Cap-Swaps:								
2004	13,340,000	5.78	4.33	—	—	No	—	(11,507)
2005	52,925,000	5.80	4.16	—	—	No	—	(64,315)
2006	21,050,000	6.20	4.73	—	—	No	—	(10,799)
Counter Swaps:								
2006	(7,300,000)	(5.59)	—	—	—	No	—	4,439
Call Options:								
2004	5,490,000	—	—	6.67	—	No	2,489	(4,840)
2005	7,300,000	—	—	6.00	—	No	3,249	(8,644)
Collars:								
2004	1,104,000	—	3.10	4.44	—	Yes	—	(2,124)
2005	4,380,000	—	3.10	4.44	—	Yes	—	(9,166)
Locked Swaps:								
2004	11,040,000	—	—	—	—	No	—	(8,462)
2005	35,550,000	—	—	—	—	No	—	(38,602)
2006	25,550,000	—	—	—	—	No	—	(22,601)
2007	25,550,000	—	—	—	—	No	—	(11,626)
Total Natural Gas							5,738	(215,961)
Oil (bbls):								
Swaps:								
2004	460,000	32.26	—	—	—	Yes	—	(7,660)
Cap-Swaps:								
2004	1,058,000	29.15	22.35	—	—	No	—	(20,924)
2005	1,995,500	40.20	31.44	—	—	No	—	(12,676)
Total Oil							—	(41,260)
Total Natural Gas and Oil							$ 5,738	$(257,221)

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally 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 as of September 30, 2004.

Based upon the market prices as of September 30, 2004, we expect to transfer approximately $97.3 million of the loss included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the hedged transactions actually occur. All hedge transactions as of September 30, 2004 are expected to mature by December 31, 2007, with the exception of the basis protection swaps which extend through 2009.

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

	2004 ($ in thousands)
Fair value of contracts outstanding as of January 1	$ (44,988)
Change in fair value of contracts during the period	(278,245)
Contracts realized or otherwise settled during the period	67,648
Fair value of new contracts when entered into during the period	(5,369)
Fair value of contracts when closed during the period	3,733
Fair value of contracts outstanding as of September 30	$ (257,221)

The change in the fair value of our derivative instruments since January 1, 2004 resulted from an increase in market prices for natural gas and oil relative to the hedged prices. 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 condensed 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 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.

	September 30, 2004 Years of Maturity							
	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
	($ in millions)							
Liabilities:								
Long-term debt, including current portion — fixed-rate	$ —	$ —	$ —	$ 209.8	$ —	$ 2,480.1	$ 2,689.9(1)	$ 2,892.4
Average interest rate	—	—	—	8.4%	—	7.5%	7.6%	7.6%
Long-term debt-variable-rate	$ —	$ —	$ —	$ 152.0	$ —	$ —	$ 152.0	$ 152.0
Average interest rate	—	—	—	4.8%	—	—	4.8%	4.8%

(1) This amount does not include the discount included in long-term debt of ($80.7) million and premium for interest rate swaps of $1.2 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving credit facility. All of our other long-term indebtedness is fixed-rate and therefore does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

Interest Rate Derivatives

We also utilize hedging strategies to manage our exposure to changes in interest rates. To the extent the interest rate swaps have been designated as fair value hedges, changes in the fair value of the derivative instrument and the corresponding debt are reflected as adjustments to interest expense in the corresponding months covered by the derivative agreement. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

In the Current Quarter, we entered into the following interest rate swaps to convert a portion of our long-term fixed-rate debt to floating rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value as of September 30, 2004 ($ in thousands)
September 2004 – August 2012	$75,000,000	9.00%	6-month LIBOR plus 452 basis points	$ 988
September 2004 – January 2015	$75,000,000	7.75%	6-month LIBOR plus 293.75 basis points	$ (781)
August 2004 – June 2014	$75,000,000	7.50%	6-month LIBOR in arrears plus 254 basis points	$ 46
August 2004 – August 2014	$75,000,000	7.00%	6-month LIBOR in arrears plus 191 basis points	—

In September 2004, we closed the 7.00% interest rate swaps listed above and received a cash settlement of $1.0 million. In October 2004, we closed the 7.50% and 7.75% interest rate swaps listed above and received cash settlements of $0.4 million and $0.5 million, respectively. Such settlement amounts will be amortized as a reduction to realized interest expense over the remaining terms of our 7.00%, 7.50% and 7.75% senior notes.

In March 2004, Chesapeake entered into an interest rate swap which requires Chesapeake to pay a fixed rate of 8.68% while the counterparty pays Chesapeake a floating rate of six month LIBOR plus 0.75% on a notional amount of $142.7 million. The counterparty may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap on March 15, 2005 and annually thereafter through March 15, 2011. The interest rate swap expires on March 15, 2012. Chesapeake may elect to terminate the swap and cause it to be settled at the then current estimated fair value of the interest rate swap at any time during the term of the swap.

As of September 30, 2004, the fair value of the interest rate swap was a liability of $34.3 million. Because the interest rate swap is not designated as a fair value hedge, changes in the fair value of the swap are recorded as adjustments to interest expense. The Current Quarter and Current Period include an unrealized loss of $5.9 million and $4.8 million, respectively, and a realized loss of $0.7 million and $1.5 million, respectively, in interest expense.

In January 2004, Chesapeake acquired a $50 million interest rate swap as part of the purchase of Concho Resources Inc. Under the terms of the interest rate swap, the counterparty pays Chesapeake a floating three month LIBOR rate and Chesapeake pays a fixed rate of 2.875%. Payments are made quarterly and the interest rate swap extends through September 2005. An initial liability of $0.6 million was recorded based on the fair value of the interest rate swap at the time of acquisition. As of September 30, 2004, the interest rate swap had a fair value of ($0.2) million. Because this instrument is not designated as a fair value hedge, an unrealized loss of $0.2 million and a negligible unrealized gain were recognized in the Current Quarter and Current Period, respectively, as part of interest expense.

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 September 30, 2004, 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.

PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Chesapeake is currently involved in various disputes incidental to its business operations. Management is of the opinion that the final resolution of such currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position or results of operations.

Item 2. ***Unregistered Sales of Equity Securities and Use of Proceeds***

Certain of our employees have purchased shares of our common stock in 401(k) plans maintained by the company which were not registered under the Securities Act of 1933. These include shares in the Chesapeake 401(k) plan which exceeded the number of shares previously registered under Form S-8 registration statements for the plan. Plan participants purchased 20,909 shares at prices ranging from $14.29 to $16.25 between July 1, 2004 and August 16, 2004. Participants in the 401(k) plan of our wholly-owned subsidiary Nomac Drilling Corporation purchased an additional 686 unregistered shares at prices ranging from $15.08 to $16.67 between July 1, 2004 and August 16, 2004. All such shares were acquired by the trustee of the plans on behalf of participants through open market purchases, and the company received no proceeds from these transactions. We filed registration statements on Form S-8 to increase the shares of Chesapeake common stock registered for the Chesapeake 401(k) plan and to register shares for the 401(k) plan of Nomac Drilling Corporation on August 17, 2004.

The following table presents information about repurchases of our common stock during the three months ended September 30, 2004:

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share (1)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs(2)
July 1, 2004 through July 31, 2004	80,274	$ 15.364	—	—
August 1, 2004 through August 31, 2004	64,596	$ 14.507	—	—
September 1, 2004 through September 30, 2004	60,033	$ 15.104	—	—
Total	204,903	$ 15.018	—	—

(1) Includes 120,194 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the Company of 84,159 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 550 shares of common stock to pay the withholding taxes in connection with the vesting of restricted stock.

(2) We make matching contributions to our 401(k) plans and 401(k) make-up plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of Company contributions. There are no other repurchase plans or programs currently authorized by the Board of Directors.

Item 3. ***Defaults Upon Senior Securities***

Not applicable.

Item 4. ***Submission of Matters to a Vote of Security Holders***

Not applicable.

Item 5. ***Other Information***

Not applicable.

Item 6. ***Exhibits***

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

Exhibit Number	Description
3.1	Chesapeake's Restated Certificate of Incorporation, as amended, together with the Certificates of Designation for the Series A Junior Participating Preferred Stock, 6.75% Cumulative Convertible Preferred Stock, 6.0% Cumulative Convertible Preferred Stock, 5.0% Cumulative Convertible Preferred Stock and 4.125% Cumulative Convertible Preferred Stock.
4.3.1	Eleventh Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.
4.3.2	Twelfth Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of April 6, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York (formerly United States Trust Company of New York), as Trustee, with respect to the 8.125% senior notes due 2011.
4.4.1	Eighth Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 8.375% senior notes due 2008.
4.4.2	Ninth Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of November 5, 2001 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 8.375% senior notes due 2008.
4.5.1	Fifth Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 9.0% senior notes due 2012.
4.5.2	Sixth Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of August 12, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 9.0% senior notes due 2012.
4.6.1	Fifth Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.75% senior notes due 2015.
4.6.2	Sixth Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.75% senior notes due 2015.
4.9.1	Fourth Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.50% senior notes due 2013.
4.9.2	Fifth Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.50% senior notes due 2013.

4.10.1	Second Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 6.875% senior notes due 2016.
4.10.2	Third Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 6.875% senior notes due 2016.
4.11.1	First Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.50% senior notes due 2014.
4.11.2	Second Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7. 50% senior notes due 2014.
4.12	Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.00% senior notes due 2014. Incorporated herein by reference to Exhibit 4.1 to Chesapeake's registration statement on Form S-4 (No. 333-118378)
4.12.1	First Supplemental Indenture dated as of August 30, 2004 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7.00% senior notes due 2014.
4.12.2	Second Supplemental Indenture dated as of September 27, 2004 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York, as Trustee, with respect to the 7. 00% senior notes due 2014.
10.1.4.1	Form of Incentive Stock Option Agreement for Chesapeake Energy Corporation 1996 Stock Option Plan.
10.1.4.2	Form of Nonqualified Stock Option Agreement for Chesapeake Energy Corporation 1996 Stock Option Plan.
10.1.5.1	Form of Nonqualified Stock Option Agreement for Chesapeake Energy Corporation 1999 Stock Option Plan.
10.1.6.1	Form of Nonqualified Stock Option Agreement for Chesapeake Energy Corporation 2000 Employee Stock Option Plan.
10.1.8.1	Form of Incentive Stock Option Agreement for Chesapeake Energy Corporation 2001 Stock Option Plan.
10.1.8.2	Form of Nonqualified Stock Option Agreement for Chesapeake Energy Corporation 2001 Stock Option Plan and Chesapeake Energy Corporation 2001 Nonqualified Stock Option Plan.
10.1.11.1	Form of Incentive Stock Option Agreement for Chesapeake Energy Corporation 2002 Stock Option Plan.
10.1.11.2	Form of Nonqualified Stock Option Agreement for Chesapeake Energy Corporation 2002 Stock Option Plan and Chesapeake Energy Corporation 2002 Nonqualified Stock Option Plan.
10.1.12.1	Form of Stock Option Agreement for Chesapeake Energy Corporation 2002 Non-Employee Director Stock Option Plan.

10.1.14.1	Form of Restricted Stock Award Agreement for Chesapeake Energy Corporation 2003 Stock Incentive Plan.
10.1.15	Form of Stock Option Grant Notice
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.

SIGNATURES

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

CHESAPEAKE ENERGY CORPORATION
(Registrant)

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon
Chairman and Chief Executive Officer

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland
Executive Vice President and Chief Financial Officer

Date: November 9, 2004