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

FORM 10-Q

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

For the quarterly period ended March 31, 2006

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

For the transition period from   to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act. Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ]

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

As of May 5, 2006, there were 382, 224,928 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2006

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2006	December 31, 2005
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 38,286	$ 60,027
Accounts receivable:		
Oil and natural gas sales	503,808	615,382
Joint interest, net of allowances of $4,311,000 and $4,904,000, respectively	83,708	84,765
Service operations	20,735	—
Related parties	15,589	12,839
Other	100,922	78,208
Deferred income taxes	—	234,592
Short-term derivative instruments	363,969	10,503
Inventory and other	67,179	87,081
Total Current Assets	1,194,196	1,183,397
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	17,380,076	15,880,919
Unevaluated properties	2,140,882	1,739,095
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(4,247,865)	(3,945,703)
Total Oil and Natural Gas Properties, at cost based on full-cost accounting	15,273,093	13,674,311
Other property and equipment	859,343	750,083
Drilling rigs	308,385	116,133
Less: accumulated depreciation and amortization of other property and equipment and drilling rigs	(133,543)	(128,640)
Total Property and Equipment	16,307,278	14,411,887
OTHER ASSETS:		
Investments	210,338	297,443
Long-term derivative instruments	176,119	78,860
Other assets	164,429	146,875
Total Other Assets	550,886	523,178
TOTAL ASSETS	$ 18,052,360	$ 16,118,462

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS – (Continued)
(Unaudited)

	March 31, 2006	December 31, 2005
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 676,739	$ 516,792
Short-term derivative instruments	191,899	577,681
Other accrued liabilities	302,071	364,501
Deferred income taxes	50,803	—
Revenues and royalties due others	288,132	394,693
Accrued interest	82,287	110,421
Total Current Liabilities	1,591,931	1,964,088
LONG-TERM LIABILITIES:		
Long-term debt, net	6,320,915	5,489,742
Deferred income tax liability	2,183,972	1,804,978
Asset retirement obligation	166,249	156,593
Long-term derivative instruments	366,432	479,996
Revenues and royalties due others	22,486	22,585
Other liabilities	37,552	26,157
Total Long-Term Liabilities	9,097,606	7,980,051
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS' EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 0 and 99,310 shares issued and outstanding as of March 31, 2006 and December 31, 2005, respectively, entitled in liquidation to $0 and $4,965,500	—	4,966
5.00% cumulative convertible preferred stock (series 2003), 842,673 and 1,025,946 shares issued and outstanding as of March 31, 2006 and December 31, 2005, respectively, entitled in liquidation to $84,267,300 and $102,594,600	84,267	102,595
4.125% cumulative convertible preferred stock, 86,310 and 89,060 shares issued and outstanding as of March 31, 2006 and December 31, 2005, respectively, entitled in liquidation to $86,310,000 and $89,060,000	86,310	89,060
5.00% cumulative convertible preferred stock (series 2005), 4,600,000 shares issued and outstanding as of March 31, 2006 and December 31, 2005, entitled in liquidation to $460,000,000	460,000	460,000
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of March 31, 2006 and December 31, 2005, entitled in liquidation to $345,000,000	345,000	345,000
5.00% cumulative convertible preferred stock (series 2005B), 5,750,000 shares issued and outstanding as of March 31, 2006 and December 31, 2005, entitled in liquidation to $575,000,000	575,000	575,000
Common Stock, $.01 par value, 500,000,000 shares authorized, 387,352,930 and 375,510,521 shares issued at March 31, 2006 and December 31, 2005, respectively	3,874	3,755
Paid-in capital	3,916,507	3,803,312
Retained earnings	1,687,214	1,100,841
Accumulated other comprehensive income (loss), net of tax of ($141,357,000) and $112,071,000, respectively	230,635	(194,972)
Unearned compensation	—	(89,242)
Less: treasury stock, at cost; 5,320,124 and 5,320,816 common shares as of March 31, 2006 and December 31, 2005, respectively	(25,984)	(25,992)
Total Stockholders' Equity	7,362,823	6,174,323
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$18,052,360	$16,118,462

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 March 31, 2006	2005
	($ in thousands, except per share data)	
REVENUES:		
Oil and natural gas sales	$ 1,510,821	$ 538,942
Marketing sales	404,367	244,508
Service operations revenue	29,379	—
Total Revenues	1,944,567	783,450
OPERATING COSTS:		
Production expenses	119,392	69,562
Production taxes	55,373	35,958
General and administrative expenses	28,791	12,067
Marketing expenses	391,360	237,276
Service operations expense	14,437	—
Oil and natural gas depreciation, depletion and amortization	304,957	180,968
Depreciation and amortization of other assets	23,872	10,082
Employee retirement expense	54,753	—
Total Operating Costs	992,935	545,913
INCOME FROM OPERATIONS	951,632	237,537
OTHER INCOME (EXPENSE):		
Interest and other income	9,636	3,357
Interest expense	(72,658)	(43,128)
Gain on sale of investment	117,396	—
Loss on repurchases or exchanges of Chesapeake debt	—	(900)
Total Other Income (Expense)	54,374	(40,671)
INCOME BEFORE INCOME TAXES	1,006,006	196,866
INCOME TAX EXPENSE:		
Current	—	—
Deferred	382,283	71,856
Total Income Tax Expense	382,283	71,856
NET INCOME	623,723	125,010
PREFERRED STOCK DIVIDENDS	(18,812)	(5,463)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(1,009)	—
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 603,902	$ 119,547
EARNINGS PER COMMON SHARE:		
Basic	$ 1.64	$ 0.39
Assuming dilution	$ 1.44	$ 0.36
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.050	$ 0.045
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):		
Basic	368,625	309,857
Assuming dilution	431,455	351,357

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)

	Three Months Ended March 31, 2006	2005
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 623,723	$ 125,010
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	325,886	189,105
Unrealized (gains) losses on derivatives	(196,611)	114,083
Deferred income taxes	382,283	71,856
Amortization of loan costs and bond discount	4,583	3,283
Realized (gains) losses on financing derivatives	(26,858)	—
Stock-based compensation	58,884	2,417
Gain on sale of investment	(117,396)	—
Income from equity investments	(4,569)	(1,167)
Loss on repurchases or exchanges of Chesapeake debt	—	900
Premiums paid for repurchasing of senior notes	—	(841)
Other	(3,062)	(24)
Change in assets and liabilities	(79,405)	8,063
Cash provided by operating activities	967,458	512,685
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(958,231)	(660,873)
Exploration and development of oil and natural gas properties	(799,098)	(451,425)
Additions to buildings and other fixed assets	(95,282)	(43,046)
Additions to drilling rig equipment	(193,252)	(11,070)
Proceeds from sale of investment in Pioneer Drilling Company	158,890	—
Additions to investments	(29,249)	(7,518)
Acquisition of trucking company, net of cash acquired	(44,916)	—
Divestitures of oil and natural gas properties	72	—
Other	1,005	(5)
Cash used in investing activities	(1,960,061)	(1,173,937)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	2,202,000	1,166,000
Payments on long-term borrowings	(1,830,000)	(501,000)
Proceeds from issuance of senior notes, net of offering costs	486,584	—
Purchases or exchanges of Chesapeake senior notes	—	(11,000)
Common stock dividends	(18,218)	(13,916)
Preferred stock dividends	(19,395)	(5,464)
Financing costs of credit facility	(3,693)	(4,640)
Purchases of treasury shares	—	(4,000)
Derivative settlements	(30,093)	—
Net increase in outstanding payments in excess of cash balance	72,356	21,345
Cash received from exercise of stock options and warrants	39,227	8,682
Excess tax benefit from stock-based compensation	77,113	—
Other financing costs	(5,019)	(1,651)
Cash provided by financing activities	970,862	654,356
Net increase (decrease) in cash and cash equivalents	(21,741)	(6,896)
Cash and cash equivalents, beginning of period	60,027	6,896
Cash and cash equivalents, end of period	$ 38,286	$ —

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 March 31, 2006	Three Months Ended March 31, 2005
	($ in thousands)	
Net income	$ 623,723	$ 125,010
Other comprehensive income, net of income tax:		
Change in fair value of derivative instruments, net of income taxes of $408,866,000 and ($63,340,000)	667,097	(110,195)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($79,012,000) and ($11,981,000)	(128,914)	(20,843)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($37,719,000) and $207,000	(61,541)	360
Unrealized gain on marketable securities, net of income taxes of $13,515,000 and $9,315,000	22,051	16,205
Reclassification of gain on sales of investments, net of income taxes of ($44,795,000) and $0	(73,086)	—
Comprehensive income	$ 1,049,330	$ 10,537

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited 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. Chesapeake's 2005 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three months ended March 31, 2006 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three months ended March 31, 2006 (the "Current Quarter") and the three months ended March 31, 2005 (the "Prior Quarter").

Stock-Based Compensation

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment*, (SFAS 123(R)) to account for stock-based employee compensation. Among other items, SFAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized in general and administrative expense and production expense. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated.

Any unearned compensation recorded under APB 25 related to stock-based compensation awards is required to be eliminated against the appropriate equity accounts. As a result, upon adoption of SFAS 123(R) we eliminated $89.2 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our condensed consolidated balance sheet.

For the three months ended March 31, 2006 and 2005, we recorded the following stock-based compensation ($ in thousands):

	Restricted Stock		Stock Options		Total	
	Current Quarter	Prior Quarter	Current Quarter	Prior Quarter	Current Quarter	Prior Quarter
Production expenses	$ 1,253	$ —	$ 201	$ —	$ 1,454	$ —
General and administrative expenses	5,020	2,298	1,179	119	6,199	2,417
Employee retirement expense	35,720	—	15,510	—	51,230	—
Oil and natural gas properties	4,242	1,825	669	—	4,911	1,825
Total	$ 46,235	$ 4,123	$ 17,559	$ 119	$ 63,794	$ 4,242

The impact to income before income taxes of adopting SFAS 123(R) for the Current Quarter was a reduction of $1.0 million. SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock ("excess tax benefits") to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the quarter ended March 31, 2006, we reported $77.1 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

Pro forma Disclosures

Prior to January 1, 2006, we accounted for our employee stock options using the intrinsic value method prescribed by APB 25. As required by SFAS 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for the three months ended March 31, 2005 ($ in thousands, except per share amounts):

Net Income:	
As reported	$ 125,010
Add: Stock-based compensation expense included in reported net income, net of tax	1,535
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of tax	(3,887)
Pro forma net income	$ 122,658
Basic earnings per common share	
As reported	$ 0.39
Pro forma	$ 0.38
Diluted earnings per common share	
As reported	$ 0.36
Pro forma	$ 0.35

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to directors in July 2005. The fair value of the awards issued is determined 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 for employees and three years for directors.

A summary of the status of the non-vested shares as of March 31, 2006, and changes during the Current Quarter, is presented below:

	Number of Non-vested Shares	Weighted Average Grant-Date Fair Value
Non-vested shares as of December 31, 2005	5,805,210	$ 18.38
Granted	1,890,990	33.04
Vested	(2,029,560)	19.22
Forfeited	(53,202)	23.78
Non-vested shares as of March 31, 2006	5,613,438	$ 22.96

The aggregate intrinsic value of restricted stock vested during the Current Quarter was approximately $62.4 million.

As of March 31, 2006, there was $115.0 million of total unrecognized compensation cost related to non-vested restricted stock. The cost is expected to be recognized over a weighted average period of 1.79 years.

During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to restricted stock of $2.9 million and $0.1 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options

We granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable over a four year period.

The following table provides information related to stock option activity for the three months ended March 31, 2006:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in thousands)
Outstanding at December 31, 2005	20,256,013	$ 6.14		
Granted	—	—		
Exercised	(8,362,875)	4.75		
Forfeited	(24,578)	9.46		
Outstanding at March 31, 2006	11,868,560	$ 7.11	5.92	$ 288,434
Exercisable at March 31, 2006	9,185,217	$ 6.73	5.64	$ 226,673

(a) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during the Current Quarter was approximately $221.2 million.

As of March 31, 2006, there was $5.3 million of total unrecognized compensation cost related to non-vested stock options. The cost is expected to be recognized over a weighted average period of 0.66 years.

During the Current Quarter and the Prior Quarter, we recognized excess tax benefits related to stock options of $74.2 million and $6.3 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural 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, 2005.

2. Financial Instruments and Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of March 31, 2006, our oil and natural 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 natural 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 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.
- Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, 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 Appalachian Basin basis protection swaps, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater 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, then 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 new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural 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 the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

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

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or natural gas from a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual prices we receive for much of our natural gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future natural gas price differentials. As of March 31, 2006, the fair value of our basis protection swaps was $309.7 million. As of March 31, 2006, our Mid-Continent basis protection swaps cover approximately 25% of our anticipated remaining Mid-Continent natural gas production in 2006, 26% in 2007, 21% in 2008 and 15% in 2009. As of March 31, 2006, our Appalachian Basin basis protection swaps cover approximately 78% of our anticipated Appalachian Basin natural gas production in 2007, 61% in 2008 and 43% in 2009.

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains included in oil and natural gas sales were $248.2 million and $40.3 million in the Current Quarter and the Prior Quarter, respectively. 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 natural gas sales.

Unrealized gains (losses) included in oil and natural gas sales were $197.6 million and ($117.1) million, in the Current Quarter and the Prior Quarter, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows 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 natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $99.3 million and ($0.6) million in the Current Quarter and the Prior Quarter, respectively.

The estimated fair values of our oil and natural gas derivative instruments as of March 31, 2006 and December 31, 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	March 31, 2006	December 31, 2005
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ (112,158)	$ (1,047,094)
Natural gas basis protection swaps	309,739	307,308
Fixed-price natural gas cap-swaps	(47,332)	(161,056)
Fixed-price natural gas counter-swaps	14,601	37,785
Natural gas call options[(a)]	(43,008)	(21,461)
Fixed-price natural gas collars	(8,784)	(9,374)
Fixed-price natural gas locked swaps	(25,428)	(34,229)
Floating-price natural gas swaps	—	2,607
Fixed-price oil swaps	(39,877)	(16,936)
Fixed-price oil cap-swaps	(4,238)	(3,364)
Estimated fair value	$ 43,515	$ (945,814)

(a) After adjusting for $53.4 million and $23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of March 31, 2006 and December 31, 2005 was $10.4 million and $1.6 million, respectively.

Based upon the market prices at March 31, 2006, we expect to transfer approximately $245 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of March 31, 2006 are expected to mature by December 31, 2009.

We have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for each of these facilities is May 2010. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. One of the hedging facilities is subject to an annual fee of 0.30% of the maximum total capacity, and each of them has 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 March 31, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $56.1 million under one of the facilities and an asset of $340.0 million under the other facility. As of May 5, 2006, the fair market value of the same transactions was an asset of approximately $1.0 million and $196.6 million, respectively. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, A*mendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives as of March 31, 2006:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at March 31, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
2Q 2006	10,510,500	4.86	—	—	Yes	$ (25,260)
3Q 2006	10,626,000	4.86	—	—	Yes	(30,235)
4Q 2006	10,626,000	4.86	—	—	Yes	(43,422)
1Q 2007	10,350,000	4.82	—	—	Yes	(57,688)
2Q 2007	10,465,000	4.82	—	—	Yes	(41,050)
3Q 2007	10,580,000	4.82	—	—	Yes	(41,743)
4Q 2007	10,580,000	4.82	—	—	Yes	(47,793)
1Q 2008	9,555,000	4.68	—	—	Yes	(51,438)
2Q 2008	9,555,000	4.68	—	—	Yes	(31,638)
3Q 2008	9,660,000	4.68	—	—	Yes	(32,071)
4Q 2008	9,660,000	4.66	—	—	Yes	(37,335)
1Q 2009	4,500,000	5.18	—	—	Yes	(18,451)
2Q 2009	4,550,000	5.18	—	—	Yes	(9,656)
3Q 2009	4,600,000	5.18	—	—	Yes	(9,965)
4Q 2009	4,600,000	5.18	—	—	Yes	(12,351)
Collars:						
1Q 2009	900,000	—	4.50	6.00	Yes	(3,304)
2Q 2009	910,000	—	4.50	6.00	Yes	(1,633)
3Q 2009	920,000	—	4.50	6.00	Yes	(1,696)
4Q 2009	920,000	—	4.50	6.00	Yes	(2,151)
Total Natural Gas						$ (498,880)

Interest Rate Derivatives

We utilize hedging strategies to manage our exposure to changes in interest rates. To the extent 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.

As of March 31, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value
				($ in thousands)
September 2004 – August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (4,131)
July 2005 – January 2015	$150,000,000	7.750%	6 month LIBOR plus 289 basis points	(8,309)
July 2005 – June 2014	$150,000,000	7.500%	6 month LIBOR plus 282 basis points	(8,677)
September 2005 – August 2014	$250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(10,738)
October 2005 – June 2015	$200,000,000	6.375%	6 month LIBOR plus 112 basis points	(5,899)
October 2005 – January 2018	$250,000,000	6.250%	6 month LIBOR plus 99 basis points	(10,655)
January 2006 – January 2016	$250,000,000	6.625%	6 month LIBOR plus 129 basis points	(6,424)
March 2006 – January 2016	$250,000,000	6.875%	6 month LIBOR plus 120 basis points	(2,921)
March 2006 – August 2017	$250,000,000	6.500%	6 month LIBOR plus 125.5 basis points	(4,003)
				$ (61,757)

Subsequent to March 31, 2006, we entered into the following interest rate swap (which qualifies as a fair value hedge) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
April 2006 – January 2018	$250,000,000	6.250%	6 month LIBOR plus 35.5 basis points

In the Current Quarter, we closed one interest rate swap for a gain totaling $1.0 million. This interest rate swap was designated as a fair value hedge, and the settlement amount received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair values 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 and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at March 31, 2006 and December 31, 2005 were $5.926 billion and $5.429 billion, respectively, compared to approximate fair values of $6.100 billion and $5.582 billion, respectively. The carrying amounts for our convertible preferred stock as of March 31, 2006 and December 31, 2005 were $1.551 billion and $1.577 billion, respectively, compared to approximate fair values of $1.618 billion and $1.686 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. 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.

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 all currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Employment Agreements with Officers

Currently, 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 agreement with the chief executive officer has a term of five years commencing July 1, 2005. The term of the agreement is automatically extended for one additional year on each January 31 unless the company provides 30 days notice of non-extension. The agreements with the chief operating officer, 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 is entitled to receive a payment in the amount of three times his base compensation and three times the value of the prior year's benefits, plus a tax gross-up payment. In addition, any stock-based awards held by the chief executive officer will immediately become 100% vested, and any unexercised options will not terminate as a result of his termination of employment. The company will also provide him office space and secretarial and accounting support for a period of 12 months after a change of control. The chief operating officer, chief financial officer and other officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year in the event of a change in control.

Environmental Risk

Due to the nature of the oil and natural 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 contingent 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 at March 31, 2006.

Other Commitments

As of March 31, 2006, Chesapeake's wholly owned subsidiary, Nomac Drilling Corporation, had contracted to acquire 23 rigs to be constructed during 2006. The total cost of the rigs will be approximately $204 million.

Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company up to $25 million each. The agreement matures on December 31, 2009. There were no outstanding borrowings under this agreement at March 31, 2006. As of May 5, 2006, there was $7.5 million outstanding under the facility.

4. Net Income Per Share

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

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

- For the Prior Quarter, outstanding options to purchase 0.1 million shares of common stock at a weighted average exercise price of $30.63 were antidilutive because the exercise price of the options was greater than the average market price of the common stock during the period.

- In the Current Quarter, holders of our 4.125% preferred stock exchanged 2,750 shares for 172,594 shares of common stock. The common stock equivalent of these preferred shares outstanding prior to these exchanges of 32,596 shares was deemed to be antidilutive and therefore excluded from the diluted shares outstanding. The associated $0.2 million of dividends and loss on exchange was also excluded from the net income utilized to determine diluted earnings per share.

- In the Current Quarter, holders of our 5% preferred stock (Series 2003) exchanged 183,273 shares for 1,140,223 shares of common stock. The common stock equivalent of these preferred shares outstanding prior to these exchanges of 235,584 shares was deemed to be antidilutive and therefore excluded from the diluted shares outstanding. The associated $0.8 million of dividends and loss on exchange was also excluded from net income utilized to determine diluted earnings per share.

During the Current Quarter, the remaining 99,310 shares of our 6.0% preferred stock were converted or exchanged into 482,694 shares of common stock.

Reconciliations for the three months ended March 31, 2006 and 2005 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	($ in thousands, except per share data)		
For the Three Months Ended March 31, 2006:			
Basic EPS:			
Income available to common shareholders	$ 603,902	368,625	$ 1.64
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 4.125% convertible preferred stock	—	5,183	
Common shares assumed issued for 4.50% convertible preferred stock	—	7,811	
Common shares assumed issued for 5.00% convertible preferred stock (series 2003)	—	5,137	
Common shares assumed issued for 5.00% convertible preferred stock (series 2005)	—	17,853	
Common shares assumed issued for 5.00% convertible preferred stock (series 2005B)	—	14,717	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 6.00% convertible preferred stock	—	416	
Employee stock options	—	9,777	
Restricted stock	—	1,936	
Preferred stock dividends	18,812	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 622,714	431,455	$ 1.44

	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the Three Months Ended March 31, 2005:			
Basic EPS:			
Income available to common shareholders	$ 119,547	309,857	$ 0.39
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 4.125% convertible preferred stock	—	18,812	
Common shares assumed issued for 5.00% convertible preferred stock (series 2003)	—	10,516	
Common shares assumed issued for 6.00% convertible preferred stock	—	499	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion, 6.00% convertible preferred stock	—	2	
Employee stock options	—	10,662	
Restricted stock	—	986	
Warrants assumed in Gothic acquisition	—	23	
Preferred stock dividends	5,463	—	
Diluted EPS Income available to common shareholders and assumed conversions	$ 125,010	351,357	$ 0.36

5. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of March 31, 2006 and December 31, 2005:

	March 31, 2006	December 31, 2005
	($ in thousands)	
7.5% Senior Notes due 2013	363,823	363,823
7.0% Senior Notes due 2014	300,000	300,000
7.5% Senior Notes due 2014	300,000	300,000
7.75% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	600,000
6.875% Senior Notes due 2016	670,437	670,437
6.5% Senior Notes due 2017	1,100,000	600,000
6.25% Senior Notes due 2018	600,000	600,000
6.875% Senior Notes due 2020	500,000	500,000
2.75% Contingent Convertible Senior Notes due 2035[a]	690,000	690,000
Revolving bank credit facility	444,000	72,000
Discount on senior notes	(98,936)	(95,577)
Discount for interest rate derivatives[b]	(48,817)	(11,349)
Total senior notes and long-term debt	$ 6,320,915	$ 5,489,742

(a) The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of these notes.

(b) See note 2 for further discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $363.8 million is due.

There were no repurchases or exchanges of Chesapeake debt in the Current Quarter. The following table sets forth the loss we incurred in connection with a repurchase of senior notes in the Prior Quarter ($ in millions):

	Notes Retired	Loss on Repurchases/Exchanges		
		Premium	Other[a]	Total
For the Three Months Ended March 31, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9

(a) Includes the write-off of unamortized discounts, deferred charges, transaction costs and derivative charges.

The senior note indentures permit us to redeem the senior notes at any time at specified make-whole or redemption prices. The indentures issued before July 2005 contain covenants limiting our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; engage in transactions with affiliates; sell assets and consolidate, merge or transfer assets.

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 wholly owned subsidiaries other than minor subsidiaries.

We have a $2.0 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006. As of March 31, 2006, we had $444.0 million of outstanding borrowings under our facility and utilized $54.2 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural 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 from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.47 to 1 and our indebtedness to EBITDA ratio was 1.95 to 1 at March 31, 2006. 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 ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion 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 $75 million.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility. The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned subsidiaries except minor subsidiaries.

6. Segment Information

In accordance with Statement of Financial Accounting Standards No. 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 reportable segments have historically been the exploration and production segment and the marketing segment. Based upon the recent growth of the company's drilling rig and trucking operations, these service operations have been presented in "Other" for all years presented. These operations previously had been considered a part of the exploration and production 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 primarily from Chesapeake-operated wells. Service operations are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment's sale of oil and natural gas related to Chesapeake's ownership interests are reflected as exploration and production revenues. Such amounts totaled $691.2 million and $405.2 million for the Current Quarter and the Prior Quarter, respectively. The following tables present selected financial information for Chesapeake according to our operating segments:

	Exploration and Production	Marketing	Other Operations	Intercompany Eliminations	Consolidated Total
			($ in thousands)		
For the Three Months Ended March 31, 2006:					
Revenues	$ 1,510,821	$ 1,095,536	$ 49,646	$ (711,436)	$ 1,944,567
Intersegment revenues	—	(691,169)	(20,267)	711,436	—
Total revenues	$ 1,510,821	$ 404,367	$ 29,379	$ —	$ 1,944,567
Income before income taxes	$ 988,823	$ 11,519	$ 11,199	$ (5,535)	$ 1,006,006
For the Three Months Ended March 31, 2005:					
Revenues	$ 538,942	$ 649,707	$ 8,989	$ (414,188)	$ 783,450
Intersegment revenues	—	(405,199)	(8,989)	414,188	—
Total revenues	$ 538,942	$ 244,508	$ —	$ —	$ 783,450
Income (loss) before income taxes	$ 191,188	$ 5,678	$ (2)	$ 2	$ 196,866
As of March 31, 2006:					
Total assets	$ 17,436,897	$ 571,413	$ 460,286	$ (416,236)	$ 18,052,360
As of December 31, 2005:					
Total assets	$ 15,722,795	$ 688,747	$ 305,875	$ (598,955)	$ 16,118,462

7. Acquisitions

Oil and Natural Gas Properties

The following table describes oil and natural gas property acquisitions of proved and unproved properties that we completed in the Current Quarter ($ in millions):

Acquisition	Location	Amount
Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
Tulsa-based oil and gas company	Texas Gulf Coast/Mid-Continent	146
Houston-based oil and gas company	Texas Gulf Coast	125
Tulsa-based oil and gas company	Ark-La-Tex	70
Houston-based oil and gas company	Various	53
Dallas-based oil and gas company	Mid-Continent	30
Other	Various	297
Total acquisitions		$ 993

We also recorded approximately $81.1 million of deferred taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

Drilling Rigs and Oilfield Trucks

In January 2006, we acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for $150 million. In February 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. We recorded approximately $24.7 million of deferred taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. The purchase price allocations reflected in the accompanying condensed consolidated financial statements for the trucking company and Martex acquisitions are preliminary, pending the completion of the final valuation of the acquired assets, which is expected to be completed in the second quarter of 2006.

8. Recently Issued Accounting Standards

The Financial Accounting Standards Board recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the Financial Accounting Standards Board issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, *Accounting for Stock-Based Compensation*. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123 (R) is more fully described in Note 1.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 is not expected to have a material impact on our financial statements.

9. Subsequent Events

On May 3, 2006, we announced offers to exchange common stock for any and all of our outstanding 86,310 shares of 4.125% Convertible Preferred Stock and 842,673 shares of 5.00% Convertible Preferred Stock (Series 2003). The offers are scheduled to expire on June 1, 2006.

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 natural gas sales, average sales prices received, expenses and other income for the three months ended March 31, 2006 (the "Current Quarter") and the three months ended March 31, 2005 (the "Prior Quarter"):

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
Net Production:		
Oil (mbbls)	2,116	1,746
Natural gas (mmcf)	124,056	94,131
Natural gas equivalent (mmcfe)	136,752	104,607
Oil and Natural Gas Sales ($ in thousands):		
Oil sales	$ 124,667	$ 79,944
Oil derivatives – realized gains (losses)	(3,808)	(7,067)
Oil derivatives – unrealized gains (losses)	(1,335)	(12,842)
Total oil sales	119,524	60,035
Natural gas sales	940,318	535,777
Natural gas derivatives – realized gains (losses)	252,029	47,415
Natural gas derivatives – unrealized gains (losses)	198,950	(104,285)
Total natural gas sales	1,391,297	478,907
Total oil and natural gas sales	$ 1,510,821	$ 538,942
Average Sales Price (excluding all gains (losses) on derivatives):		
Oil ($ per bbl)	$ 58.92	$ 45.79
Natural gas ($ per mcf)	$ 7.58	$ 5.69
Natural gas equivalent ($ per mcfe)	$ 7.79	$ 5.89
Average Sales Price (excluding unrealized gains (losses) on derivatives):		
Oil ($ per bbl)	$ 57.12	$ 41.74
Natural gas ($ per mcf)	$ 9.61	$ 6.20
Natural gas equivalent ($ per mcfe)	$ 9.60	$ 6.27
Other Operating Income ($ in thousands):[(a)]		
Marketing	$ 13,007	$ 7,232
Service operations	$ 14,942	$ —
Other Operating Income ($ per mcfe):		
Marketing	$ 0.10	$ 0.07
Service operations	$ 0.11	$ —
Expenses ($ per mcfe):		
Production expenses	$ 0.87	$ 0.66
Production taxes	$ 0.40	$ 0.34
General and administrative expenses	$ 0.21	$ 0.12
Oil and natural gas depreciation, depletion and amortization	$ 2.23	$ 1.73
Depreciation and amortization of other assets	$ 0.17	$ 0.10
Interest expense[(b)]	$ 0.52	$ 0.44
Interest Expense ($ in thousands):		
Interest expense	$ 72,898	$ 47,293
Interest rate derivatives – realized (gains) losses	(1,244)	(1,121)
Interest rate derivatives – unrealized (gains) losses	1,004	(3,044)
Total interest expense	$ 72,658	$ 43,128
Net Wells Drilled	255	169
Net Producing Wells as of the End of the Period	17,669	8,611

(a) Includes revenue and operating costs.

(b) Includes the effects of realized gains (losses) from interest rate derivatives, but does not include the effects of unrealized gains (losses) and is net of amounts capitalized.

Chesapeake is the second largest independent producer of natural gas in the United States and we own interests in approximately 31,900 producing oil and natural gas wells. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the southwestern U.S. and in the Appalachian Basin of the eastern U.S. Our most important operating area has historically been the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At March 31, 2006, 49% of our proved reserves were located in the Mid-Continent. During the past four years, we have also built significant positions in the South Texas and Texas Gulf Coast regions, the Permian Basin of West Texas and eastern New Mexico, the Barnett Shale area of north-central Texas, the Ark-La-Tex area of East Texas and northern Louisiana and the emerging Fayetteville Shale play in Arkansas. As a result of our recent acquisition of Columbia Energy Resources, LLC and its subsidiaries, including Columbia Natural Resources, LLC ("CNR"), we now have a significant presence in the Appalachian Basin, principally in West Virginia, eastern Kentucky, eastern Ohio and southern New York.

Chesapeake attributes its strong organic growth rates during the first quarter of 2006 and in this decade to management's early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry – people, land and seismic. Since 2000, Chesapeake has invested $3.8 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be the largest inventories of onshore leasehold (8.9 million net acres) and 3-D seismic (12.3 million acres) in the U.S. On this leasehold, the company has more than a 10-year drilling inventory of an estimated 29,000 drilling locations.

In addition, Chesapeake has significantly strengthened its technical capabilities during the past five years by increasing its land, geoscience and engineering staff by 425% to over 650 employees. Today, the company has more than 3,600 employees, of which approximately 70% work in the company's E&P operations and 30% work in the company's oilfield service operations.

Oil and natural gas production for the Current Quarter was 136.8 bcfe, an increase of 32.2 bcfe, or 31% over the 104.6 bcfe produced in the Prior Quarter. We have increased our production for 19 consecutive quarters. During these 19 quarters, Chesapeake's U.S. production has increased 280% for an average compound quarterly growth rate of 7% and an average compound annual growth rate of 32%.

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 $9.60 per mcfe in the Current Quarter compared to $6.27 per mcfe in the Prior Quarter. The increase in prices resulted in an increase in revenue of $455.6 million, and increased production resulted in an increase in revenue of $201.5 million, for a total increase in revenue of $657.1 million (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist thereby contributing to relatively high wellhead price realizations for our production.

During the Current Quarter, Chesapeake drilled 262 (210 net) operated wells and participated in another 371 (45 net) wells operated by other companies. The company's drilling success rate was 97% for company-operated wells and 98% for non-operated wells. During the Current Quarter, Chesapeake invested $505 million in operated wells (using an average of 77 operated rigs), $110 million in non-operated wells (using an average of approximately 75 non-operated rigs) and $200 million in acquiring new 3-D seismic data and leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $1.0 billion during the Current Quarter, including amounts paid for unproved leasehold and excluding $81 million of deferred taxes in connection with certain corporate acquisitions. We expect to continue replacing reserves through the drillbit and acquisitions, although the timing and magnitude of future additions are uncertain.

Chesapeake began 2006 with estimated proved reserves of 7.521 tcfe and based on internal estimates ended the Current Quarter with 7.811 tcfe, an increase of 290 bcfe, or 4%. During the Current Quarter, we replaced 137 bcfe of production with an estimated 427 bcfe of new proved reserves, for a reserve replacement rate of 312%. Reserve replacement through the drillbit was 184 bcfe, or 135% of production (including 76 bcfe of positive performance revisions and 88 bcfe of downward revisions resulting from oil and natural gas price declines between December 31, 2005 and March 31, 2006) and 43% of the total increase. Reserve replacement through acquisitions was 243 bcfe, or 177% of production and 57% of the total increase. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2006 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within a year.

On February 10, 2006, Chesapeake sold its 7.7 million shares of common stock of Pioneer Drilling Company and received proceeds of $159 million. The sale resulted in a gain to Chesapeake of $117 million on an investment which had an average holding period of approximately 2.3 years. With proceeds from the Pioneer sale, the company acquired 13 U.S. onshore rigs from privately-owned Martex Drilling Company, L.L.P., for $150 million in February 2006, adding to the rig fleet of Chesapeake's 100% owned drilling rig subsidiary, Nomac Drilling Corporation.

In anticipation of today's tight drilling rig market, Chesapeake began making a series of investments in drilling rigs in 2001. In that year, Chesapeake formed Nomac, with an investment of $26 million to build and refurbish five drilling rigs. Chesapeake has now invested a total of $283 million to build or acquire 34 operating rigs, another $47 million in 23 rigs that Nomac is currently building and has budgeted an additional $157 million for completion of these rigs.

Chesapeake has also invested $52 million in two private drilling rig companies, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns approximately 45% and 49%, respectively. DHS owns 12 drilling rigs and has three rigs under construction. Mountain owns one drilling rig and has ordered another nine rigs for delivery later in 2006 and 2007. Chesapeake's drilling rig investments have served as a partial hedge to rising service costs and have also provided competitive advantages in making acquisitions and in developing its own leasehold on a more timely and efficient basis.

As of March 31, 2006, the company's debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders' equity) was 46% compared to 47% as of December 31, 2005. During the Current Quarter, we received net proceeds of $487 million through the issuance of $500 million principal amount of 6.50% Senior Notes due 2017. We issued 1.8 million shares of common stock in exchange for outstanding shares of our 4.125% and 5.0% (Series 2003) preferred stock and upon conversions of our 6.0% preferred stock. As a result of our debt transactions in 2005 and the Current Quarter, we have extended the average maturity of our long-term debt to over ten years and have lowered our average interest rate to approximately 6.3%.

We intend to continue to focus on improving the strength of our balance sheet. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt in the future.

Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward's Resignation Agreement provided for the immediate vesting of all of his unvested stock options and restricted stock on February 10, 2006. As a result of such vesting, options to purchase 724,615 shares of Chesapeake's common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock became immediately vested and the company incurred a non-cash charge of $54.8 million in the Current Quarter. Mr. Ward exercised all of his stock options on March 14, 2006 and paid the company an aggregate exercise price of $37.1 million.

Liquidity and Capital Resources

Sources of Liquidity

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our drilling capital expenditures in 2006. Our budget for drilling, land and seismic activities during 2006 is currently between $3.2 billion and $3.5 billion. We believe this level of exploration and development will be sufficient to increase our reserves in 2006 and achieve our goal of an organic growth rate of at least 10% over 2005 production and a 24% increase in total production (inclusive of acquisitions completed or scheduled to close in 2006 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2006). However, 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 in 2006.

Cash provided by operating activities was $967 million in the Current Quarter compared to $513 million in the Prior Quarter. The $454 million increase was primarily due to higher realized prices and higher oil and natural gas production. We expect that 2006 production will be higher than in 2005 and that cash provided by operating activities in 2006 will exceed 2005 levels. While a precipitous decline in natural gas prices in the remainder of 2006 would affect the amount of cash flow that would be generated from operations, we have 72% of our expected oil production for 2006 hedged at an average NYMEX price of $62.63 per barrel of oil and 80% of our expected natural gas production for 2006 hedged at an average NYMEX price of $9.37 per mmbtu. This level of hedging provides greater certainty of the cash flow we will receive for a substantial portion of our remaining 2006 production. Depending on changes in oil and natural 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. At March 31, 2006 and May 5, 2006, we had issued $50 million and $65 million, respectively, of letters of credit securing our performance of hedging contracts. To mitigate the liquidity impact of potential collateral requirements, we have either negotiated caps on the amount of collateral that we might be required to post or eliminated the collateral requirement entirely with six of our counterparties. All of our existing commodity hedges other than those we acquired from CNR and those not under our secured hedge facilities (described below under *Contractual Obligations*) are with these counterparties and the maximum amount of collateral that we would be required to post with them is no more than $250 million in the aggregate.

A significant source of liquidity is our $2.0 billion syndicated revolving bank credit facility which matures in February 2011. At May 5, 2006, there was $1.3 billion of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $2.202 billion and repaid $1.830 billion in the Current Quarter, and we borrowed $1.166 billion and repaid $501 million in the Prior Quarter under the credit facility. We incurred $3.7 million and $4.6 million of financing costs related to amendments to the credit facility agreement in the Current Quarter and the Prior Quarter, respectively.

We believe that our available cash, cash provided by operating activities and funds available under our revolving 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 long-term financing for acquisitions. We have sold 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 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 1A of our Form 10-K for the year ended December 31, 2005.

We issued $500 million principal amount of 6.5% Senior Notes due 2017 and received net proceeds of $486.6 million in the Current Quarter. There were no issuances of equity securities in the Current Quarter and no issuances of debt or equity securities in the Prior Quarter.

We qualify as a well-known seasoned issuer (WKSI), as defined in Rule 405 of the Securities Act of 1933, and therefore we may utilize automatic shelf registration to register future debt and equity issuances with the Securities and Exchange Commission. A prospectus supplement will be prepared at the time of an offering and will contain a description of the security issued, the plan of distribution and other information.

We paid dividends on our common stock of $18.2 million and $13.9 million in the Current Quarter and the Prior Quarter, respectively. The board of directors increased the quarterly dividend on common stock from $0.045 to $0.05 per share beginning with the dividend paid in July 2005. We paid dividends on our preferred stock of $19.4 million and $5.5 million in the Current Quarter and the Prior Quarter, respectively. We received $39.2 million and

$8.7 million from the exercise of employee and director stock options and warrants in the Current Quarter and the Prior Quarter, respectively. The Current Quarter amount included $37.1 million paid by Mr. Ward to exercise all of his stock options following his resignation in February 2006.

In the Current Quarter, we paid $30.1 million to settle derivative liabilities assumed from CNR.

On January 1, 2006, we adopted SFAS 123(R), which requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In the Current Quarter, we reported a tax benefit of $77.1 million.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $72.4 million and $21.3 million in the Current Quarter and the Prior Quarter, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake; however, there were no such transactions in the Current Quarter. During the Prior Quarter, we repurchased $11.0 million of our 8.375% Senior Notes due 2008 and paid a premium of $0.8 million.

Cash used in investing activities increased to $1.960 billion during the Current Quarter, compared to $1.174 billion during the Prior Quarter. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Three Months Ended March 31,	
Oil and Natural Gas Investing Activities:	**2006**	**2005**
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 412.5	$ 436.3
Acquisition of unproved properties	545.7	224.6
Exploration and development of oil and natural gas properties	596.8	373.5
Leasehold acquisitions	172.6	51.8
Geological and geophysical costs	27.5	14.2
Other oil and natural gas activities	2.2	11.9
Total oil and natural gas investing activities	1,757.3	1,112.3
Other Investing Activities:		
Additions to buildings and other fixed assets	95.3	43.0
Additions to drilling rig equipment (including Martex Drilling Company, L.L.P)	193.3	11.1
Additions to investments	29.2	7.5
Proceeds from sale of investment in Pioneer Drilling Company	(158.9)	—
Acquisition of trucking company, net of cash acquired	44.9	—
Other	(1.0)	—
Total other investing activities	202.8	61.6
Total cash used in (provided by) investing activities	$ 1,960.1	$ 1,173.9

Our accounts receivable are primarily from purchasers of oil and natural gas ($503.8 million at March 31, 2006) and exploration and production companies which own interests in properties we operate ($83.7 million at March 31, 2006). 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 table describes investing transactions related to the acquisition of proved and unproved properties that we completed in the Current Quarter ($ in millions):

Acquisition	Location	Amount
Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
Tulsa-based oil and gas company	Texas Gulf Coast/Northern Mid-Continent	146
Houston-based oil and gas company	Texas Gulf Coast	125
Tulsa-based oil and gas company	Ark-La-Tex	70
Houston-based oil and gas company	Various	53
Dallas-based oil and gas company	Mid-Continent	30
Other	Various	297
Total oil and natural gas acquisitions		993
Less cash deposits paid in 2005		(35)
Total oil and natural gas acquisitions in the Current Quarter		$ 958

We also recorded approximately $81.1 million of deferred taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

In January 2006, we acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and northern Louisiana, for $150 million. In February 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. We recorded approximately $24.7 million of deferred taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. The purchase price allocations reflected in the accompanying condensed consolidated financial statements for the trucking company and Martex acquisitions are preliminary, pending the completion of the final valuation of the acquired assets, which is expected to be completed in the second quarter of 2006.

During 2005 and continuing in 2006, we have taken several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over ten years with an average interest rate of approximately 6.3%. Maintaining a debt-to-total-capitalization ratio of below 50% and reducing debt per mcfe of proved reserves remain key goals of our business strategy.

We completed the following significant financing transactions in the Current Quarter:

- Amended and restated our revolving bank credit facility, increasing the commitments to $2.0 billion and extending the maturity date to February 2011.

- Issued an additional $500 million of our 6.5% Senior Notes due 2017 in a private placement and used the proceeds of approximately $487 million to repay outstanding borrowings under our revolving bank credit facility incurred primarily to fund our recent acquisitions.

Contractual Obligations

We currently have a $2.0 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006. As of March 31, 2006, we had $444 million of outstanding borrowings under this facility and had utilized $54.2 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural 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) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% per annum 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 a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility, our indebtedness to total capitalization ratio was 0.47 to 1 and our indebtedness to EBITDA ratio was 1.95 to 1 at March 31, 2006. 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 ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion 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 $75 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 March 31, 2006, we were required to post $50 million of collateral in the form of letters of credit with respect to such derivative transactions. These collateral requirements were $65 million as of May 5, 2006. Future collateral requirements are uncertain and will depend on arrangements with our counterparties and fluctuations in natural gas and oil prices and interest rates. Excluding transactions outstanding under our secured hedging facilities and the transactions we acquired from CNR which are specifically secured under our credit facility, we currently have arrangements with six of our most active counterparties, with which we have outstanding transactions, that limit the amount of collateral that we would be required to post with them to no more than $250 million in the aggregate.

We also have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for these facilities is May 2010. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. One of the hedging facilities is subject to an annual fee of 0.3% of the maximum total capacity and each of them has 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 March 31, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $56.1 million under one of the facilities and an asset of $340.0 million under the other facility. As of May 5, 2006, the fair market value of the same transactions was an asset of approximately $1.0 million and $196.6 million, respectively. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly-owned subsidiaries except minor subsidiaries. Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

As of March 31, 2006, our senior notes represented approximately $5.9 billion of our long-term debt and consisted of the following ($ in thousands):

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
6.375% Senior Notes due 2015	600,000
6.625% Senior Notes due 2016	600,000
6.875% Senior Notes due 2016	670,437
6.5% Senior Notes due 2017	1,100,000
6.25% Senior Notes due 2018	600,000
6.875% Senior Notes due 2020	500,000
2.75% Contingent Convertible Senior Notes due 2035	690,000
Discount on senior notes	(98,936)
Discount for interest rate derivatives	(48,817)
	$ 5,876,915

No scheduled principal payments are required under our senior notes until 2013, when $363.8 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of the notes.

As of March 31, 2006 and currently, debt ratings for the senior notes are Ba2 by Moody's Investor Service (stable outlook), BB by Standard & Poor's Ratings Services (stable outlook) and BB by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally with all of our other unsecured indebtedness. All of our wholly-owned subsidiaries except minor subsidiaries guarantee the notes. The indentures (other than the indentures issued after June 2005) contain covenants limiting our ability and our restricted subsidiaries' ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of March 31, 2006, we estimate that secured commercial bank indebtedness of approximately $3.4 billion could have been incurred under the most restrictive indenture covenant.

Results of Operations — Three Months Ended March 31, 2006 vs. March 31, 2005

General. For the Current Quarter, Chesapeake had net income of $623.7 million, or $1.44 per diluted common share, on total revenues of $1.945 billion. This compares to net income of $125.0 million, or $0.36 per diluted common share, on total revenues of $783.5 million during the Prior Quarter. The Current Quarter net income included, on a pre-tax basis, $196.6 million net unrealized gains on oil and natural gas and interest rate derivatives, a gain on the sale of an investment of $117.4 million and $54.8 million of early employee retirement expense. The Prior Quarter net income included, on a pre-tax basis, $114.1 million in net unrealized losses on oil and natural gas and interest rate derivatives and a $0.9 million loss on repurchase of debt.

Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.511 billion compared to $538.9 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 136.8 bcfe at a weighted average price of $9.60 per mcfe, compared to 104.6 bcfe produced in the Prior Quarter at a weighted average price of $6.27 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on derivatives of $197.6 million and ($117.1) million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $455.6 million and increased production resulted in a $201.5 million increase, for a total increase in revenues of $657.1 million (excluding unrealized gains or losses on oil and natural 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 2005 and the Current Quarter.

For the Current Quarter, we realized an average price per barrel of oil of $57.12, compared to $41.74 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 $9.61 and $6.20 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $248.2 million, or $1.82 per mcfe, in the

Current Quarter and a net increase of $40.3 million, or $0.39 per mcfe, in the Prior Quarter.

The change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $12.4 million and $11.8 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 $2.1 million and $2.0 million, respectively, without considering the effect of derivative activities.

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

	For the Three Months Ended March 31,			
	2006		2005	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	73,924	54%	72,812	70%
South Texas and Texas Gulf Coast	20,286	15	11,937	11
Ark-La-Tex and Barnett Shale	20,155	15	11,423	11
Permian Basin	11,462	8	7,787	7
Appalachian Basin	10,293	7	—	—
Other	632	1	648	1
Total Production	136,752	100%	104,607	100%

Natural gas production represented approximately 91% of our total production volume on an equivalent basis in the Current Quarter, compared to 90% in the Prior Quarter.

Marketing Sales and Operating Expenses. Marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake realized $404.4 million in oil and natural gas marketing sales to third parties in the Current Quarter, with corresponding oil and natural gas marketing expenses of $391.4 million, for a net margin of $13.0 million. This compares to sales of $244.5 million, expenses of $237.3 million and a net margin of $7.2 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and natural gas marketing sales volumes and an increase in oil and natural gas prices.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake realized $29.4 million in service operations revenue in the Current Quarter with corresponding service operations expenses of $14.4 million, for a net margin of $15.0 million principally associated with the acquisition of Martex Drilling Company, L.L.P. and a trucking company in the Current Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $119.4 million in the Current Quarter compared to $69.6 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.87 per mcfe in the Current Quarter compared to $0.66 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher third-party field service costs, energy costs, ad valorem tax increases and personnel costs. We expect that production expenses for 2006 will range from $0.85 to $0.95 per mcfe produced.

Production Taxes. Production taxes were $55.4 million and $36.0 million in the Current Quarter and the Prior Quarter, respectively. On a unit-of-production basis, production taxes were $0.40 per mcfe in the Current Quarter compared to $0.34 per mcfe in the Prior Quarter. The $19.4 million increase in production taxes in the Current Quarter is due primarily to 32.1 bcfe of increased production and the increase in sales prices (excluding gains or losses on derivatives). In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for 2006 to range from $0.41 to $0.46 per mcfe based on NYMEX prices of $60.00 per barrel of oil and natural gas wellhead prices ranging from $7.35 to $8.35 per mcf.

General and Administrative Expenses. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and natural gas properties, were $28.8 million in the Current Quarter and $12.1 million in the Prior Quarter. General and administrative expenses were $0.21 and $0.12 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of the company's overall growth. This growth has resulted in a substantial increase in employees and related costs. Included in general and administrative expenses is stock-based compensation of $6.2 million and $2.4 million for the Current Quarter and Prior Quarter, respectively. We anticipate that general and administrative expenses for

2006 will be between $0.21 and $0.28 per mcfe produced (including stock-based compensation ranging from $0.06 and $0.08 per mcfe produced).

Until December 31, 2005, as permitted under Statement of Financial Accounting Standards ("SFAS") No. 123, *Accounting for Stock-Based Compensation*, as amended, we accounted for our stock options under the recognition and measurement provisions of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Generally, we recognized no compensation cost on grants of employee stock options because the exercise price was equal to the market price of our common stock on the date of grant. Effective January 1, 2006, we implemented the fair value recognition provisions of SFAS 123(R), *Share-Based Payment,* using the modified-prospective transition method. Under this transition method, compensation cost in 2006 includes the portion vesting in the period for (1) all share-based payments granted prior to, but not vested as of January 1, 2006, based on the grant date fair value estimated in accordance with the original provisions of SFAS 123 and (2) all share-based payments granted subsequent to January 1, 2006, based on the grant fair value estimated in accordance with the provisions of SFAS 123(R). Results for prior periods have not been restated.

Stock-based compensation expense increased from $2.4 million in the Prior Quarter to $6.2 million in the Current Quarter. Of this increase, $1.0 million was due to the expensing of stock options pursuant to SFAS 123(R), $2.6 million was due to a higher number of restricted shares granted being expensed over their vesting periods during the Current Quarter compared to the Prior Quarter, and $0.2 million was due to stock granted to a new director.

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 $35.0 million and $20.5 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $305.0 million and $181.0 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 $2.23 and $1.73 in the Current Quarter and in the Prior Quarter, respectively. The $0.50 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 2006 to be between $2.30 and $2.35 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $23.9 million in the Current Quarter, compared to $10.1 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of higher depreciation resulting from the acquisition of various gathering facilities, compression equipment, construction of new buildings at our corporate headquarters complex and at various field office locations, the purchase of additional drilling rigs and oilfield trucks and the purchase of additional information technology equipment and software in 2005 and the Current Quarter. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 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 seven years. To the extent drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect 2006 depreciation and amortization of other assets to be between $0.16 and $0.20 per mcfe produced.

Employee Retirement Expense. Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward's Resignation Agreement provided for the immediate vesting of all of his unvested stock options and restricted stock on February 10, 2006. As a result of such vesting, options to purchase 724,615 shares of Chesapeake's common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock became immediately vested. As a result, we incurred an expense of $54.8 million in the Current Quarter.

Interest and Other Income. Interest and other income was $9.6 million in the Current Quarter compared to $3.4 million in the Prior Quarter. The Current Quarter income consisted of $1.7 million of interest income, $4.8 million related to earnings of equity investees, a $3.0 million gain on sale of assets and $0.1 million of miscellaneous income. The Prior Quarter income consisted of $2.7 million of interest income, $0.1 million related to earnings of equity investees and $0.6 million of miscellaneous income.

Interest Expense. Interest expense increased to $72.7 million in the Current Quarter compared to $43.1 million in the Prior Quarter as follows:

	Three Months Ended March 31, 2006	Three Months Ended March 31, 2005
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 102.6	$ 61.9
Capitalized interest	(31.3)	(16.0)
Amortization of loan discount	1.6	1.3
Unrealized (gain) loss on interest rate derivatives	1.0	(3.0)
Realized (gain) loss on interest rate derivatives	(1.2)	(1.1)
Total interest expense	$ 72.7	$ 43.1
Average long-term borrowings	$ 5,775	$ 3,091

We use interest rate derivatives 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 are recorded on the 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 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 7A-Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in the Current Quarter compared to $0.44 per mcfe in the Prior Quarter. We expect interest expense for 2006 to be between $0.52 and $0.57 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investment. In the Current Quarter, Chesapeake sold its investment in Pioneer Drilling Company ("Pioneer") common stock, realizing proceeds of $158.9 million and a gain of $117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Loss on Repurchases or Exchanges of Chesapeake Debt. We repurchased or exchanged Chesapeake debt in the Prior Quarter and incurred a loss in connection with the transaction. The following table shows the loss related to the transaction ($ in millions):

	Notes Retired	Loss on Repurchases/Exchanges Premium	Other [(a)]	Total
For the Three Months Ended March 31, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with notes retired and transaction costs.

There were no repurchases or exchanges of Chesapeake debt in the Current Quarter.

Income Tax Expense. Chesapeake recorded income tax expense of $382.3 million in the Current Quarter, compared to income tax expense of $71.9 million in the Prior Quarter. Our effective income tax rate increased to 38% in the Current Quarter compared to 36.5% in the Prior Quarter. The increase in the Current Quarter reflected the impact state income taxes and permanent differences had on our overall effective rate. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural 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, 2005.

Recently Issued Accounting Standards

The Financial Accounting Standards Board recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the Financial Accounting Standards Board issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 is not expected to have a material impact on our 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 statements regarding oil and natural gas reserve estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expected oil and natural gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations and expected future expenses. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under "Risk Factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005 and include:

- the volatility of oil and natural gas prices,
- our level of indebtedness,
- the strength and financial resources of our competitors,
- the availability of capital on an economic basis to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities,
- inability to effectively integrate and operate acquired companies and properties,
- unsuccessful exploration and development drilling,
- declines in the value of our oil and natural gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,

- lower oil and natural gas prices negatively affecting our ability to borrow, and
- drilling and operating risks.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report 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 Natural gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of March 31, 2006, our oil and natural 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 natural 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 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.
- Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, 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 Appalachian Basin basis protection swaps, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater 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, then 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 new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural 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 the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

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

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or natural gas from a specified delivery point. We currently have basis protection swaps covering four different delivery points which correspond to the actual prices we receive for much of our natural gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future natural gas price differentials. As of March 31, 2006, the fair value of our basis protection swaps was $309.7 million. As of March 31, 2006, our Mid-Continent basis protection swaps covered approximately 25% of our anticipated Mid-Continent natural gas production remaining in 2006, 26% in 2007, 21% in 2008 and 15% in 2009. As of March 31, 2006, our Appalachian Basin basis protection swaps cover approximately 78% of our anticipated Appalachian Basin natural gas production in 2007, 61% in 2008 and 43% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $248.2 million and $40.3 million in the Current Quarter and the Prior Quarter, respectively. 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 natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $197.6 million and ($117.1) million in the Current Quarter and the Prior Quarter, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows 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 natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $99.3 million and ($0.6) million in the Current Quarter and the Prior Quarter, respectively.

As of March 31, 2006, we had the following open oil and natural gas derivative instruments (excluding CNR derivatives assumed) designed to hedge a portion of our oil and natural gas production for periods after March 2006:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received	Fair Value at March 31, 2006 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
2Q 2006	86,665,000	$ 9.10	$ —	$ —	$ —	Yes	$ —	$ 154,912
3Q 2006	90,300,000	9.14	—	—	—	Yes	—	124,884
4Q 2006	82,355,000	9.70	—	—	—	Yes	—	52,297
1Q 2007	76,950,000	11.01	—	—	—	Yes	—	28,061
2Q 2007	52,325,000	9.15	—	—	—	Yes	—	9,218
3Q 2007	52,900,000	9.18	—	—	—	Yes	—	6,721
4Q 2007	52,900,000	9.78	—	—	—	Yes	—	2,563
1Q 2008	38,220,000	10.65	—	—	—	Yes	—	1,265
2Q 2008	38,220,000	8.37	—	—	—	Yes	—	(336)
3Q 2008	38,640,000	8.41	—	—	—	Yes	—	(940)
4Q 2008	38,640,000	9.01	—	—	—	Yes	—	(2,827)
1Q 2009	900,000	10.53	—	—	—	Yes	—	535
2Q 2009	910,000	8.29	—	—	—	Yes	—	562
3Q 2009	920,000	8.34	—	—	—	Yes	—	536
4Q 2009	920,000	8.95	—	—	—	Yes	—	487
Basis Protection Swaps (Mid-Continent):								
2Q 2006	30,940,000	—	—	—	(0.31)	No	—	27,598
3Q 2006	31,280,000	—	—	—	(0.31)	No	—	21,773
4Q 2006	33,720,000	—	—	—	(0.32)	No	—	37,633
1Q 2007	32,850,000	—	—	—	(0.29)	No	—	39,290
2Q 2007	34,125,000	—	—	—	(0.35)	No	—	23,753
3Q 2007	34,500,000	—	—	—	(0.35)	No	—	20,351
4Q 2007	35,720,000	—	—	—	(0.32)	No	—	30,255
1Q 2008	33,215,000	—	—	—	(0.30)	No	—	27,570
2Q 2008	26,845,000	—	—	—	(0.25)	No	—	14,516
3Q 2008	27,140,000	—	—	—	(0.25)	No	—	12,401
4Q 2008	31,410,000	—	—	—	(0.28)	No	—	19,398
1Q 2009	26,100,000	—	—	—	(0.32)	No	—	14,621
2Q 2009	20,020,000	—	—	—	(0.28)	No	—	6,655
3Q 2009	20,240,000	—	—	—	(0.28)	No	—	5,469
4Q 2009	20,240,000	—	—	—	(0.28)	No	—	8,892
Basis Protection Swaps (Appalachian Basin):								
1Q 2007	4,500,000	—	—	—	0.36	No	—	(366)
2Q 2007	4,550,000	—	—	—	0.36	No	—	119
3Q 2007	4,600,000	—	—	—	0.36	No	—	132
4Q 2007	4,600,000	—	—	—	0.36	No	—	(71)
1Q 2008	4,550,000	—	—	—	0.34	No	—	(424)
2Q 2008	4,550,000	—	—	—	0.34	No	—	151
3Q 2008	4,600,000	—	—	—	0.34	No	—	164
4Q 2008	4,600,000	—	—	—	0.34	No	—	(37)
1Q 2009	2,700,000	—	—	—	0.31	No	—	(226)
2Q 2009	2,730,000	—	—	—	0.31	No	—	68
3Q 2009	2,760,000	—	—	—	0.31	No	—	75
4Q 2009	2,760,000	—	—	—	0.31	No	—	(21)
Cap-Swaps:								
2Q 2006	11,830,000	6.84	5.13	—	—	No	—	(5,496)
3Q 2006	11,960,000	6.85	5.13	—	—	No	—	(13,232)
4Q 2006	11,960,000	6.89	5.13	—	—	No	—	(28,604)
Counter Swaps:								
2Q 2006	(1,820,000)	(5.35)	—	—	—	No	—	3,532
3Q 2006	(1,840,000)	(5.33)	—	—	—	No	—	4,473
4Q 2006	(1,840,000)	(5.50)	—	—	—	No	—	6,596

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received	Fair Value at March 31, 2006 ($ in thousands)
Call Options:								
2Q 2006	1,820,000	12.50	—	—	—	No	1,911	(7)
3Q 2006	1,840,000	12.50	—	—	—	No	1,932	(200)
4Q 2006	1,840,000	12.50	—	—	—	No	1,932	(1,086)
1Q 2007	6,300,000	11.58	—	—	—	No	9,855	(9,648)
2Q 2007	6,370,000	9.96	—	—	—	No	9,965	(7,009)
3Q 2007	6,440,000	10.04	—	—	—	No	10,074	(7,971)
4Q 2007	6,440,000	10.56	—	—	—	No	10,074	(10,230)
1Q 2008	1,820,000	12.50	—	—	—	No	1,911	(2,962)
2Q 2008	1,820,000	12.50	—	—	—	No	1,911	(963)
3Q 2008	1,840,000	12.50	—	—	—	No	1,932	(1,137)
4Q 2008	1,840,000	12.50	—	—	—	No	1,932	(1,795)
Locked Swaps:								
2Q 2006	7,590,000	—	—	—	—	No	—	(4,392)
3Q 2006	7,680,000	—	—	—	—	No	—	(4,703)
4Q 2006	6,440,000	—	—	—	—	No	—	(4,706)
1Q 2007	6,300,000	—	—	—	—	No	—	(4,789)
2Q 2007	6,370,000	—	—	—	—	No	—	(2,517)
3Q 2007	6,440,000	—	—	—	—	No	—	(2,049)
4Q 2007	6,440,000	—	—	—	—	No	—	(2,272)
Total Natural Gas							53,429	586,510
Oil (bbls):								
Swaps:								
2Q 2006	1,153,000	61.53	—	—	—	Yes	—	(7,375)
3Q 2006	1,196,000	62.50	—	—	—	Yes	—	(8,048)
4Q 2006	1,196,000	62.31	—	—	—	Yes	—	(8,604)
1Q 2007	720,000	62.55	—	—	—	Yes	—	(5,122)
2Q 2007	455,000	64.49	—	—	—	Yes	—	(2,364)
3Q 2007	460,000	64.16	—	—	—	Yes	—	(2,450)
4Q 2007	460,000	63.73	—	—	—	Yes	—	(2,518)
1Q 2008	364,000	66.75	—	—	—	Yes	—	(757)
2Q 2008	364,000	66.34	—	—	—	Yes	—	(780)
3Q 2008	368,000	65.92	—	—	—	Yes	—	(822)
4Q 2008	368,000	65.53	—	—	—	Yes	—	(849)
1Q 2009	45,000	65.64	—	—	—	Yes	—	(41)
2Q 2009	45,000	66.27	—	—	—	Yes	—	(45)
3Q 2009	46,000	65.92	—	—	—	Yes	—	(49)
4Q 2009	46,000	65.56	—	—	—	Yes	—	(53)
Cap-Swaps:								
2Q 2006	136,500	57.82	40.67	—	—	No	—	(1,387)
3Q 2006	138,000	57.82	40.67	—	—	No	—	(1,599)
4Q 2006	92,000	56.53	40.00	—	—	No	—	(1,252)
Total Oil							—	(44,115)
Total Natural Gas and Oil							$ 53,429	$ 542,395

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 at March 31, 2006.

Based upon the market prices at March 31, 2006, we expect to transfer approximately $245 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months when the transactions actually occur. All transactions hedged as of March 31, 2006 are expected to mature by December 31, 2009.

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

	2006 ($ in thousands)
Fair value of contracts outstanding, as of January 1	$ (945,814)
Change in fair value of contracts during the period	1,269,849
Fair value of contracts when entered into during the period	(32,300)
Contracts realized or otherwise settled during the period	(248,220)
Fair value of contracts outstanding, as of March 31	$ 43,515

The change in the fair value of our derivative instruments since January 1, 2006 resulted from the settlement of derivatives for a realized gain as well as a decrease in oil and natural gas prices. Derivative instruments reflected as current in the condensed consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and natural 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.

We assumed certain liabilities related to open derivative positions in connection with the CNR acquisition. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, A*mendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives as of March 31, 2006:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at March 31, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
2Q 2006	10,510,500	4.86	—	—	Yes	$ (25,260)
3Q 2006	10,626,000	4.86	—	—	Yes	(30,235)
4Q 2006	10,626,000	4.86	—	—	Yes	(43,422)
1Q 2007	10,350,000	4.82	—	—	Yes	(57,688)
2Q 2007	10,465,000	4.82	—	—	Yes	(41,050)
3Q 2007	10,580,000	4.82	—	—	Yes	(41,743)
4Q 2007	10,580,000	4.82	—	—	Yes	(47,793)
1Q 2008	9,555,000	4.68	—	—	Yes	(51,438)
2Q 2008	9,555,000	4.68	—	—	Yes	(31,638)
3Q 2008	9,660,000	4.68	—	—	Yes	(32,071)
4Q 2008	9,660,000	4.66	—	—	Yes	(37,335)
1Q 2009	4,500,000	5.18	—	—	Yes	(18,451)
2Q 2009	4,550,000	5.18	—	—	Yes	(9,656)
3Q 2009	4,600,000	5.18	—	—	Yes	(9,965)
4Q 2009	4,600,000	5.18	—	—	Yes	(12,351)

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at March 31, 2006 ($ in thousands)
Collars:						
1Q 2009	900,000	—	4.50	6.00	Yes	(3,304)
2Q 2009	910,000	—	4.50	6.00	Yes	(1,633)
3Q 2009	920,000	—	4.50	6.00	Yes	(1,696)
4Q 2009	920,000	—	4.50	6.00	Yes	(2,151)
Total Natural Gas						$ (498,880)

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of March 31, 2006, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity							
	2006	**2007**	**2008**	**2009**	**2010**	**Thereafter**	**Total**	**Fair Value**
					($ in millions)			
Liabilities:								
Long-term debt — fixed-rate[(a)]	$ —	$ —	$ —	$ —	$ —	$ 6,024.7	$ 6,024.7	$ 6,099.8
Average interest rate	—	—	—	—	—	6.3%	6.3%	6.3%
Long-term debt — variable rate	$ —	$ —	$ —	$ —	$ —	$ 444.0	$ 444.0	$ 444.0
Average interest rate	—	—	—	—	—	7.1%	7.1%	7.1%

(a) This amount does not include the discount included in long-term debt of ($98.9) million and the discount for interest rate swaps of ($48.8) 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 bank 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 debt.

Interest Rate Derivatives

We use interest rate derivatives 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 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.

As of March 31, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value
				($ in thousands)
September 2004 – August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (4,131)
July 2005 – January 2015	$150,000,000	7.750%	6 month LIBOR plus 289 basis points	(8,309)
July 2005 – June 2014	$150,000,000	7.500%	6 month LIBOR plus 282 basis points	(8,677)
September 2005 – August 2014	$250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(10,738)
October 2005 – June 2015	$200,000,000	6.375%	6 month LIBOR plus 112 basis points	(5,899)
October 2005 – January 2018	$250,000,000	6.250%	6 month LIBOR plus 99 basis points	(10,655)
January 2006 – January 2016	$250,000,000	6.625%	6 month LIBOR plus 129 basis points	(6,424)
March 2006 – January 2016	$250,000,000	6.875%	6 month LIBOR plus 120 basis points	(2,921)
March 2006 – August 2017	$250,000,000	6.500%	6 month LIBOR plus 125.5 basis points	(4,003)
				$ (61,757)

Subsequent to March 31, 2006, we entered into the following interest rate swap (which qualifies as a fair value hedge) to convert a portion of our long-term fixed-rate debt to floating-rate debt:

Term	Notional Amount	Fixed Rate	Floating Rate
April 2006 – January 2018	$250,000,000	6.250%	6 month LIBOR plus 35.5 basis points

In the Current Quarter, we closed one interest rate swap for a gain totaling $1.0 million. This interest rate swap was designated as a fair value hedge, and the settlement amount received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

ITEM 4. *Controls and Procedures*

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. At the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake's disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

No changes in Chesapeake's internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, Chesapeake'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 currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. *Risk Factors*

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under "Risk Factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

The following table presents information about repurchases of our common stock during the three months ended March 31, 2006:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share[(a)]	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[(b)]
January 1, 2006 through January 31, 2006	216,872	$ 32.894	—	—
February 1, 2006 through February 28, 2006	44,017	31.316	—	—
March 1, 2006 through March 31, 2006	50,618	31.268	—	—
Total	311,507	$ 32.406	—	—

(a) Includes 149,954 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the company of 9,065 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 152,488 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) 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.

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
2	Purchase Agreement dated as of September 30, 2005 between Chesapeake and Triana Energy Holdings, LLC relating to the purchase and sale of Columbia Energy Resources, LLC. Incorporated herein by reference to Exhibit 2 to Chesapeake's current report on Form 8-K filed November 1, 2005.
3.1.1	Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake's Form 10-Q for the quarter ended March 31, 2005.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake's Form 10-Q for the quarter ended March 31, 2005.
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended. Incorporated herein by reference to Exhibit 3.1.4 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005.
3.1.4	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.5 to Chesapeake's annual report on Form 10-K for the year ended December 31, 2005.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K dated November 7, 2005.
3.1.6	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake's Form 10-Q for the quarter ended March 31, 2005.
3.1.7	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake's current report on Form 8-K filed September 15, 2005.
12*	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
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.

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* Filed herewith.
** Furnished as provided in Item 601 of Regulation S-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15 (d) 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 of the Board and
Chief Executive Officer

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

Date: May 10, 2006