CHESAPEAKE ENERGY CORP
Form 10-Q
August 09, 2006
Table of Contents

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 June 30, 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 **(State or other jurisdiction of** **incorporation or organization)**	**73-1395733** **(I.R.S. Employer** **Identification No.)**
6100 North Western Avenue **Oklahoma City, Oklahoma** **(Address of principal executive offices)**	**73118** **(Zip Code)**

(405) 848-8000

Registrant s telephone number, including area code

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

Indicate by check mark whether the registrant is 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 August 4, 2006, there were 425,152,539 shares of our $0.01 par value common stock outstanding.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED JUNE 30, 2006

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2006	December 31, 2005
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 366,270	$ 60,027
Accounts receivable:		
Oil and natural gas sales	420,171	615,382
Joint interest, net of allowances of $4,355,000 and $4,904,000, respectively	105,495	84,765
Service operations	16,945	
Related parties	10,202	12,839
Other	99,042	78,208
Deferred income taxes		234,592
Short-term derivative instruments	570,414	10,503
Inventory and other	67,198	87,081
Total Current Assets	1,655,737	1,183,397
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	18,616,481	15,880,919
Unevaluated properties	2,580,753	1,739,095
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(4,573,109)	(3,945,703)
Total oil and natural gas properties, at cost based on full-cost accounting	16,624,125	13,674,311
Gathering systems	375,271	345,266
Drilling rigs	360,336	116,133
Buildings and land	324,471	233,467
Compressors	81,001	61,142
Other	164,158	110,208
Less: accumulated depreciation and amortization of other property and equipment	(153,993)	(128,640)
Total Property and Equipment	17,775,369	14,411,887
OTHER ASSETS:		
Investments	158,664	297,443
Long-term derivative instruments	254,071	78,860
Other assets	217,210	146,875
Total Other Assets	629,945	523,178
TOTAL ASSETS	$ 20,061,051	$ 16,118,462

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	June 30, 2006	December 31, 2005
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 705,992	$ 516,792
Short-term derivative instruments	197,152	577,681
Other accrued liabilities	336,378	364,501
Deferred income taxes	129,326	
Revenues and royalties due others	288,452	394,693
Accrued interest	119,169	110,421
Total Current Liabilities	1,776,469	1,964,088
LONG-TERM LIABILITIES:		
Long-term debt, net	6,330,115	5,489,742
Deferred income tax liability	2,435,731	1,804,978
Asset retirement obligation	171,430	156,593
Long-term derivative instruments	299,837	479,996
Revenues and royalties due others	23,397	22,585
Other liabilities	33,886	26,157
Total Long-Term Liabilities	9,294,396	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 June 30, 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), 38,625 and 1,025,946 shares issued and outstanding as of June 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $3,862,500 and $102,594,600	3,863	102,595
4.125% cumulative convertible preferred stock, 3,065 and 89,060 shares issued and outstanding as of June 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $3,065,000 and $89,060,000	3,065	89,060
5.00% cumulative convertible preferred stock (series 2005), 4,600,000 shares issued and outstanding as of June 30, 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 June 30, 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 June 30, 2006 and December 31, 2005, entitled in liquidation to $575,000,000	575,000	575,000
6.25% mandatory convertible preferred stock, 2,000,000 and 0 shares issued and outstanding as of June 30, 2006 and December 31, 2005, entitled in liquidation to $500,000,000	500,000	
Common Stock, $.01 par value, 750,000,000 and 500,000,000 shares authorized, 420,459,575 and 375,510,521 shares issued at June 30, 2006 and December 31, 2005, respectively	4,205	3,755
Paid-in capital	4,735,291	3,803,312
Retained earnings	2,005,428	1,100,841
Accumulated other comprehensive income (loss), net of tax of ($238,272,000) and $112,071,000, respectively	397,349	(194,972)

Unearned compensation		(89,242)
Less: treasury stock, at cost; 1,583,810 and 5,320,816 common shares as of June 30, 2006 and December 31, 2005, respectively	(39,015)	(25,992)
Total Stockholders Equity	8,990,186	6,174,323
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 20,061,051	$ 16,118,462

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	($ in thousands, except per share data)			
REVENUES:				
Oil and natural gas sales	$ 1,186,383	$ 772,401	$ 2,697,204	$ 1,311,343
Marketing sales	367,610	275,617	771,977	520,125
Service operations revenue	30,023		59,402	
Total Revenues	1,584,016	1,048,018	3,528,583	1,831,468
OPERATING COSTS:				
Production expenses	120,697	72,333	240,089	141,895
Production taxes	33,923	47,253	89,296	83,211
General and administrative expenses	33,555	11,788	62,346	23,855
Marketing expenses	355,688	270,003	747,048	507,279
Service operations expense	15,667		30,104	
Oil and natural gas depreciation, depletion and amortization	328,159	209,371	633,116	390,339
Depreciation and amortization of other assets	23,163	11,807	47,035	21,889
Employee retirement expense			54,753	
Total Operating Costs	910,852	622,555	1,903,787	1,168,468
INCOME FROM OPERATIONS	673,164	425,463	1,624,796	663,000
OTHER INCOME (EXPENSE):				
Interest and other income	4,974	2,005	14,610	5,362
Interest expense	(73,456)	(53,902)	(146,114)	(97,030)
Gain on sale of investment			117,396	
Loss on repurchases or exchanges of Chesapeake debt		(68,400)		(69,300)
Total Other Income (Expense)	(68,482)	(120,297)	(14,108)	(160,968)
INCOME BEFORE INCOME TAXES	604,682	305,166	1,610,688	502,032
INCOME TAX EXPENSE:				
Current				
Deferred	244,779	111,387	627,062	183,243
Total Income Tax Expense	244,779	111,387	627,062	183,243
NET INCOME	359,903	193,779	983,626	318,789
PREFERRED STOCK DIVIDENDS	(18,228)	(9,859)	(37,040)	(15,322)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(9,547)	(4,743)	(10,556)	(4,743)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 332,128	$ 179,177	$ 936,030	$ 298,724

EARNINGS PER COMMON SHARE:

Basic	$ 0.87	$ 0.58	$ 2.50	$ 0.96
Assuming dilution	$ 0.82	$ 0.52	$ 2.27	$ 0.88
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.060	$ 0.050	$ 0.110	$ 0.095
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):				
Basic	380,675	311,181	374,683	310,523
Assuming dilution	428,169	364,063	433,414	356,478

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 983,626	$ 318,789
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	674,074	408,084
Unrealized (gains) losses on derivatives	(212,286)	29,896
Deferred income taxes	627,062	183,243
Amortization of loan costs and bond discount	9,420	6,909
Realized (gains) losses on financing derivatives	(59,953)	
Stock-based compensation	66,835	4,923
Gain on sale of investment	(117,396)	
Income from equity investments	(6,981)	(2,169)
Loss on repurchases or exchanges of Chesapeake debt		69,300
Premiums paid for repurchasing of senior notes		(60,390)
Other	(3,372)	(229)
Change in assets and liabilities	84,115	61,561
Cash provided by operating activities	2,045,144	1,019,917
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(1,704,039)	(1,435,132)
Exploration and development of oil and natural gas properties	(1,688,849)	(954,785)
Additions to buildings and other fixed assets	(181,147)	(98,389)
Additions to drilling rig equipment	(244,203)	(29,255)
Proceeds from sale of investment in Pioneer Drilling Company	158,890	
Additions to investments	(38,433)	(22,422)
Acquisition of trucking company, net of cash acquired	(45,166)	
Deposits for acquisitions	(42,500)	
Other	1,390	105
Cash used in investing activities	(3,784,057)	(2,539,878)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	4,055,000	2,419,000
Payments on long-term borrowings	(4,127,000)	(2,023,000)
Proceeds from issuance of senior notes, net of offering costs	969,193	1,180,766
Proceeds from issuance of common stock, net of offering costs	698,932	
Proceeds from issuance of preferred stock, net of offering costs	484,843	447,167
Purchases or exchanges of Chesapeake senior notes		(547,684)
Common stock dividends	(37,038)	(27,901)
Preferred stock dividends	(38,155)	(10,928)

Financing costs of credit facility	(4,074)	(4,645)
Purchases of treasury shares	(86,185)	(4,000)
Derivative settlements	(50,720)	
Net increase in outstanding payments in excess of cash balance	42,373	75,164
Cash received from exercise of stock options and warrants	67,595	11,600
Excess tax benefit from stock-based compensation	81,492	
Other financing costs	(11,100)	(2,474)
Cash provided by financing activities	2,045,156	1,513,065
Net increase (decrease) in cash and cash equivalents	306,243	(6,896)
Cash and cash equivalents, beginning of period	60,027	6,896
Cash and cash equivalents, end of period	$ 366,270	$

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

6

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	($ in thousands)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 147,576	$ 105,072
Income taxes, net of refunds received	$	$

SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

For the six months ended June 30, 2006 and 2005, holders of our 6.0% cumulative convertible preferred stock converted 99,310 and 1,735 shares, respectively, into 482,694 and 8,432 shares, respectively, of common stock.

For the six months ended June 30, 2006 and 2005, holders of our 4.125% cumulative convertible preferred stock exchanged 2,750 and 45,000 shares, respectively, for 172,594 and 2,911,250 shares, respectively, of common stock in privately negotiated exchanges.

For the six months ended June 30, 2006, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of common stock in privately negotiated exchanges.

During the six months ended June 30, 2006, we completed tender offers for our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock, issuing 5.2 million shares of our common stock in exchange for 83,245 shares of the 4.125% preferred stock, which represented 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, and 5.0 million shares of our common stock in exchange for 804,048 shares of the 5.0% (Series 2003) preferred stock, which represented 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding. No cash was received or paid in connection with these transactions.

As of June 30, 2006 and 2005, dividends payable on our common and preferred stock were $41.7 million and $25.4 million, respectively.

For the six months ended June 30, 2006 and 2005, oil and gas properties were adjusted by $81.4 million and $251.7 million, respectively, for net tax liabilities related to acquisitions.

For the six months ended June 30, 2006 and 2005, $41.6 million and $22.4 million, respectively, of accrued exploration and development costs were recorded as additions to oil and gas properties.

We recorded non-cash asset additions to net oil and gas properties of $9.1 million and $6.5 million for the six months ended June 30, 2006 and 2005, respectively, for asset retirement obligations.

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Six Months Ended June 30,	
	2006	2005
	($ in thousands)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,576,621	$ 490,906
Issuance of 6.25% mandatory convertible preferred stock	500,000	
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)		460,000
Exchange of common stock for 85,995 and 45,000 shares of 4.125% preferred stock	(85,995)	(45,000)
Exchange of common stock for 987,321 and 0 shares of 5.00% preferred stock (Series 2003)	(98,732)	
Exchange of common stock for 99,310 and 1,735 shares of 6.00% preferred stock, respectively	(4,966)	(87)
Balance, end of period	1,886,928	905,819
COMMON STOCK:		
Balance, beginning of period	3,755	3,169
Issuance of 25,000,000 and 0 shares of common stock, respectively	250	
Exchange of 12,016,423 and 2,919,682 shares of common stock for preferred stock	120	29
Exercise of stock options and warrants	62	23
Restricted stock grants	18	18
Balance, end of period	4,205	3,239
PAID-IN CAPITAL:		
Balance, beginning of period	3,803,312	2,440,105
Issuance of common stock	726,000	
Exchange of 12,016,423 and 2,919,682 shares of common stock for preferred stock, respectively	189,573	45,058
Equity-based compensation	71,702	29,004
Adoption of SFAS 123(R)	(89,242)	
Offering expenses	(42,464)	(12,833)
Exercise of stock options and warrants	67,533	11,578
Release of 6,400,000 shares from treasury stock upon exercise of stock options	(71,874)	
Tax benefit from exercise of stock options and restricted stock	81,492	8,483
Preferred stock conversion/exchange expenses	(741)	
Balance, end of period	4,735,291	2,521,395
RETAINED EARNINGS:		
Balance, beginning of period	1,100,841	262,987
Net income	983,626	318,789
Dividends on common stock	(43,611)	(29,699)
Dividends on preferred stock	(35,428)	(15,061)
Balance, end of period	2,005,428	537,016
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(194,972)	20,425
Hedging activity	674,920	(79,670)

Marketable securities activity	(82,599)	23,483
Balance, end of period	397,349	(35,762)
UNEARNED COMPENSATION:		
Balance, beginning of period	(89,242)	(32,618)
Restricted stock granted		(29,437)
Amortization of unearned compensation		8,085
Adoption of SFAS 123(R)	89,242	
Balance, end of period		(53,970)
TREASURY STOCK COMMON:		
Balance, beginning of period	(25,992)	(22,091)
Purchase of 2,707,471 and 257,220 shares of treasury stock, respectively	(86,185)	(4,000)
Release of 6,400,000 shares upon exercise of stock options	71,874	
Shares released for company benefit plans	1,288	
Balance, end of period	(39,015)	(26,091)
TOTAL STOCKHOLDERS EQUITY	$ 8,990,186	$ 3,851,646

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
	($ in thousands)			
Net income	$ 359,903	$ 193,779	$ 983,626	$ 318,789
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $229,459,000, $18,778,000, $632,482,000 and ($44,563,000)	381,951	32,668	1,049,048	(77,527)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($85,843,000), $10,964,000, ($163,735,000) and ($1,017,000)	(141,816)	19,074	(270,730)	(1,769)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($24,891,000), ($422,000), ($61,500,000) and ($215,000)	(41,857)	(734)	(103,398)	(374)
Unrealized gain (loss) on marketable securities, net of income taxes of ($18,777,000), $4,183,000, ($5,659,000) and $13,498,000	(31,564)	7,278	(9,513)	23,483
Reclassification of gain on sales of investments, net of income taxes of $0, $0, ($45,824,000) and $0			(73,086)	
Comprehensive income	$ 526,617	$ 252,065	$ 1,575,947	$ 262,602

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

Table of Contents

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 and six months ended June 30, 2006 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2006 (the Current Quarter and the Current Period , respectively) and the three and six months ended June 30, 2005 (the Prior Quarter and the Prior Period , respectively).

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 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 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. 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

For the three and six months ended June 30, 2006 and 2005, we recorded the following stock-based compensation ($ in thousands):

	Restricted Stock Three Months Ended June 30, 2006	Restricted Stock Three Months Ended June 30, 2005	Stock Options Three Months Ended June 30, 2006	Stock Options Three Months Ended June 30, 2005	Total Three Months Ended June 30, 2006	Total Three Months Ended June 30, 2005
Production expenses	$ 1,195	$	$ 179	$	$ 1,374	$
General and administrative expenses	5,098	2,224	1,479	282	6,577	2,506
Oil and natural gas properties	4,045	1,894	596		4,641	1,894
Total	$ 10,338	$ 4,118	$ 2,254	$ 282	$ 12,592	$ 4,400

	Restricted Stock Six Months Ended June 30, 2006	Restricted Stock Six Months Ended June 30, 2005	Stock Options Six Months Ended June 30, 2006	Stock Options Six Months Ended June 30, 2005	Total Six Months Ended June 30, 2006	Total Six Months Ended June 30, 2005
Production expenses	$ 2,448	$	$ 380	$	$ 2,828	$
General and administrative expenses	10,118	4,522	2,658	401	12,776	4,923
Employee retirement expense	35,720		15,510		51,230	
Oil and natural gas properties	8,287	3,719	1,265		9,552	3,719
Total	$ 56,573	$ 8,241	$ 19,813	$ 401	$ 76,386	$ 8,642

The impact to income before income taxes of adopting SFAS 123(R) for the Current Quarter and the Current Period was a reduction of $0.9 million and $1.9 million, respectively. 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 six months ended June 30, 2006, we reported $81.5 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 and non-employee director 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 and six months ended June 30, 2005 ($ in thousands, except per share amounts):

	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net Income:		
As reported	$ 193,779	$ 318,789
Add: Stock-based compensation expense included in reported net income, net of tax	1,591	3,126
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of tax	(4,071)	(7,958)

Pro forma net income	$	191,299	$	313,957
Basic earnings per common share				
As reported	$	0.58	$	0.96
Pro forma	$	0.57	$	0.95
Diluted earnings per common share				
As reported	$	0.52	$	0.88
Pro forma	$	0.51	$	0.87

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee 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 non-employee directors.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

A summary of the status of the unvested shares of restricted stock as of June 30, 2006, and changes during the Current Period, is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2006	5,805,210	$ 18.38
Granted	2,019,295	32.89
Vested	(2,099,789)	19.27
Forfeited	(96,626)	24.28
Unvested shares as of June 30, 2006	5,628,090	$ 23.15

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $64.6 million.

As of June 30, 2006, there was $109.6 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.82 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to restricted stock of $0.1 million, a nominal amount, $3.0 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 during the Current Period:

	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 January 1, 2006	20,256,013	$ 6.14		
Exercised	(12,589,138)	5.30		
Forfeited	(34,845)	9.37		
Outstanding at June 30, 2006	7,632,030	$ 7.51	5.79	$ 173,612
Exercisable at June 30, 2006	5,596,137	$ 7.36	5.50	$ 128,148

(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 Period was approximately $329.2 million.

As of June 30, 2006, there was $3.8 million of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of 0.53 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $4.3 million, $2.0 million, $78.5 million and $8.3 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 June 30, 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, which have negative differentials to NYMEX, 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, which have positive differentials to NYMEX, 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, 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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 June 30, 2006, the fair value of our basis protection swaps was $244.3 million. As of June 30, 2006, our Mid-Continent basis protection swaps cover approximately 25% of our anticipated remaining Mid-Continent natural gas production in 2006, 25% in 2007, 20% in 2008 and 14% in 2009. As of June 30, 2006, our Appalachian Basin basis protection swaps cover approximately 65% of our anticipated Appalachian Basin natural gas production in 2007, 61% in 2008 and 28% 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 (losses) included in oil and natural gas sales were $257.4 million, ($44.4) million, $505.6 million and ($4.0) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, 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 $16.5 million, $84.1 million, $214.1 million and ($33.1) million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, 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 $65.6 million, $1.2 million, $164.9 million and $0.6 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

The estimated fair values of our oil and natural gas derivative instruments as of June 30, 2006 and December 31, 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2006	December 31, 2005
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ 357,876	$ (1,047,094)
Natural gas basis protection swaps	244,269	307,308
Fixed-price natural gas cap-swaps	(23,646)	(161,056)
Fixed-price natural gas counter-swaps	6,399	37,785
Natural gas call options[(a)]	(38,667)	(21,461)
Fixed-price natural gas collars	(8,912)	(9,374)
Fixed-price natural gas locked swaps	(21,036)	(34,229)
Floating-price natural gas swaps		2,607
Fixed-price oil swaps	(80,404)	(16,936)
Fixed-price oil cap-swaps	(5,859)	(3,364)
Estimated fair value	$ 430,020	$ (945,814)

(a) After adjusting for $51.5 million and $23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of June 30, 2006 and December 31, 2005 was $12.8 million and $1.6 million, respectively.

Based upon the market prices at June 30, 2006, we expect to transfer approximately $364.3 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 June 30, 2006 are expected to mature by December 31, 2009.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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. Both of the hedging facilities are subject to a 1.0% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of June 30, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $108.7 million under one of the facilities and an asset of $490.7 million under the other facility. As of August 4, 2006, the fair market value of the same transactions was an asset of approximately $16.4 million and $246.5 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 our acquisition of Columbia Natural Resources, LLC in November 2005. 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 does 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, *Amendment 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 June 30, 2006:

Natural Gas (mmbtu):	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 June 30, 2006 ($ in thousands)
Swaps:						
3Q 2006	10,626,000	$ 4.86	$	$	Yes	$ (13,382)
4Q 2006	10,626,000	4.86			Yes	(34,595)
1Q 2007	10,350,000	4.82			Yes	(55,646)
2Q 2007	10,465,000	4.82			Yes	(34,517)
3Q 2007	10,580,000	4.82			Yes	(36,574)
4Q 2007	10,580,000	4.82			Yes	(46,556)
1Q 2008	9,555,000	4.68			Yes	(53,329)
2Q 2008	9,555,000	4.68			Yes	(26,996)
3Q 2008	9,660,000	4.68			Yes	(28,549)
4Q 2008	9,660,000	4.66			Yes	(37,506)
1Q 2009	4,500,000	5.18			Yes	(19,734)
2Q 2009	4,550,000	5.18			Yes	(8,558)
3Q 2009	4,600,000	5.18			Yes	(9,262)

4Q 2009	4,600,000	5.18			Yes		(13,166)
Collars:							
1Q 2009	900,000		4.50	6.00	Yes		(3,543)
2Q 2009	910,000		4.50	6.00	Yes		(1,457)
3Q 2009	920,000		4.50	6.00	Yes		(1,590)
4Q 2009	920,000		4.50	6.00	Yes		(2,322)
Total Natural Gas						$	(427,282)

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were $1.2 million, $0.7 million, $2.4 million and $1.8 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were ($0.8) million, $0.1 million, ($1.8) million and $3.2 million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

As of June 30, 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	$ (5,308)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(10,900)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(11,193)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(15,016)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(9,590)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(16,012)
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points	(11,478)
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points	(7,276)
March 2006 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 125.5 basis points	(10,435)
April 2006 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 35.5 basis points	(5,316)
				$ (102,524)

In the Current Period, 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 June 30, 2006 and December 31, 2005 were $6.419 billion and $5.429 billion, respectively, compared to approximate fair values of $6.242 billion and $5.582 billion, respectively. The carrying amounts for our convertible preferred stock as of June 30, 2006 and December 31, 2005 were $1.887 billion and $1.577 billion, respectively, compared to approximate fair values of $1.885 billion and $1.686 billion, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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. Accounts receivable potentially subject us to concentrations of credit risk as well. 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, various benefits and eligibility for bonus compensation. 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, 2006. 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 June 30, 2006.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Other Commitments

As of June 30, 2006, Chesapeake s wholly owned subsidiary, Nomac Drilling Corporation, had contracted to acquire 18 rigs to be constructed during 2006 and 2007. The total remaining cost of the rigs will be approximately $115 million.

Currently, Chesapeake has contracts with various drilling contractors to use 46 rigs in 2006 with terms of one to three years. As of June 30, 2006, the minimum aggregate drilling rig commitment was approximately $400 million.

As of June 30, 2006, Chesapeake had agreed to invest approximately $70 million to acquire a drilling contractor and an affiliated trucking company in the Appalachian Basin. Through this acquisition, Chesapeake will acquire 15 rigs. This transaction closed on July 27, 2006.

As of June 30, 2006, Chesapeake had agreed to acquire oil and natural gas properties and mid-stream natural gas systems from Four Sevens Oil Co., Ltd. and Sinclair Oil Corporation for $845 million in cash. This transaction closed on July 28, 2006.

Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which the company is a 49% equity owner, up to $25 million each through December 31, 2009. At June 30, 2006, there was a $12.5 million loan outstanding under this agreement.

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 and the Prior Period, outstanding options to purchase 0.2 million and 0.1 million shares of common stock at a weighted average exercise price of $26.53 and $27.88 were antidilutive because the exercise price of the options was greater than the average market price of the common stock during the period.

For the Current Quarter, Prior Quarter and Prior Period, diluted shares do not include the common stock equivalent of our 4.125% preferred stock outstanding prior to conversion (convertible into 3,406,130, 2,613,403 and 2,657,704 shares, respectively), and the preferred stock dividend adjustment to net income does not include $8.0 million, $5.1 million and $5.5 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on dilutive earnings per share would have been antidilutive.

For the Current Quarter, diluted shares do not include the common stock equivalent of our 5.0% (Series 2003) preferred stock outstanding prior to conversion (convertible into 3,339,576 shares), and the preferred stock dividend adjustment to net income does not include $2.8 million of dividends and loss on conversion related to these preferred shares, as the effect on dilutive earnings per share would have been antidilutive.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Reconciliations for the three months ended June 30, 2006 and 2005 and the six months ended June 30, 2006 and 2005 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	($ in thousands, except per share data)		
For the Three Months Ended June 30, 2006:			
Basic EPS:			
Income available to common shareholders	$ 332,128	380,675	$ 0.87
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		184	
Common shares assumed issued for 4.50% convertible preferred stock		7,811	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		235	
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	
Common shares assumed issued for 6.25% convertible preferred stock		189	
Employee stock options		4,986	
Restricted stock		1,519	
Preferred stock dividends	16,985		
Diluted EPS Income available to common shareholders and assumed conversions	$ 349,113	428,169	$ 0.82
For the Three Months Ended June 30, 2005:			
Basic EPS:			
Income available to common shareholders	$ 179,177	311,181	$ 0.58
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		16,110	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		10,516	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		14,168	
Common shares assumed issued for 6.00% convertible preferred stock		493	
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		5	
Employee stock options		10,408	
Restricted stock		1,175	
Warrants assumed in Gothic acquisition		7	
Preferred stock dividends	9,550		

Diluted EPS Income available to common shareholders and assumed conversions	$ 188,727	364,063	$ 0.52
For the Six Months Ended June 30, 2006:			
Basic EPS:			
Income available to common shareholders	$ 936,030	374,683	$ 2.50
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		184	
Common shares assumed issued for 4.50% convertible preferred stock		7,811	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		235	
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	
Common shares assumed issued for 6.25% convertible preferred stock		95	
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		207	
4.125% convertible preferred stock		4,215	
5.00% convertible preferred stock (Series 2003)		4,233	
Employee stock options		7,369	
Restricted stock		1,812	
Loss on redemption of preferred stock	10,556		
Preferred stock dividends	37,040		
Diluted EPS Income available to common shareholders and assumed conversions	$ 983,626	433,414	$ 2.27

19

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Income (Numerator)	Shares (Denominator)	Per Share Amount
For the Six Months Ended June 30, 2005:			
Basic EPS:			
Income available to common shareholders	$ 298,724	310,523	$ 0.96
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		16,110	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		10,516	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005) `		7,123	
Common shares assumed issued for 6.00% convertible preferred stock		493	
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		7	
Employee stock options		10,539	
Restricted stock		1,151	
Warrants assumed in Gothic acquisition		16	
Preferred stock dividends	14,549		
Diluted EPS Income available to common shareholders and assumed conversions	$ 313,273	356,478	$ 0.88

5. Stockholders Equity

The following is a summary of the changes in our common shares issued for the six months ended June 30, 2006 and 2005:

	2006	2005
	(in thousands)	
Shares outstanding at January 1	375,511	316,941
Stock option and warrant exercises	6,176	2,265
Restricted stock issuances	1,756	1,746
Preferred stock conversions/exchanges	12,017	2,920
Common stock issuances	25,000	
Shares outstanding at June 30	420,460	323,872

The following is a summary of the changes in our preferred shares outstanding for the six months ended June 30, 2006 and 2005:

6.00%	5%	4.125%	4.50%	5%	6.25%

		(2003)		**5% (2005)**		**(2005B)**	
			(in thousands)				
Shares outstanding at January 1, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,000
Conversion/exchange of preferred for common stock	(99)	(987)	(86)				
Shares outstanding at June 30, 2006		39	3	4,600	3,450	5,750	2,000
Shares outstanding at January 1, 2005	103	1,725	313				
Preferred stock issuances				4,600			
Conversion/exchange of preferred for common stock	(2)		(45)				
Shares outstanding at June 30, 2005	101	1,725	268	4,600			

In connection with the exchanges and conversions noted above, we recorded a loss of $9.5 million, $4.7 million, $10.6 million and $4.7 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

During the Current Period, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of our common stock.

During the Current Period, holders of our 4.125% cumulative convertible preferred stock exchanged 2,750 shares for 172,594 shares of our common stock.

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

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

During the Current Quarter, we completed tender offers for our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock, issuing 5.2 million shares of our common stock in exchange for 83,245 shares of the 4.125% preferred stock, which represented 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, and 5.0 million shares of our common stock in exchange for 804,048 shares of the 5.0% (Series 2003) preferred stock, which represented 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding. No cash was received or paid in connection with these transactions.

In June 2006, we issued 2,000,000 shares of 6.25% mandatory convertible preferred stock, par value $0.01 per share and liquidation preference $250 per share, in a public offering for net proceeds of $484.8 million. We issued an additional 300,000 shares of preferred stock in July 2006, upon the exercise of the underwriters option to purchase the additional shares, for net proceeds of $72.5 million.

In June 2006, we issued 25,000,000 shares of Chesapeake common stock at $29.05 per share in a public offering for net proceeds of $698.9 million. We issued an additional 3.75 million shares in July 2006 at the same price pursuant to the underwriters exercise of their overallotment option to purchase the additional shares for net proceeds of $104.9 million.

6. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of June 30, 2006 and December 31, 2005:

	June 30, 2006	December 31, 2005
	($ in thousands)	
7.5% Senior Notes due 2013	$ 363,823	$ 363,823
7.625% Senior Notes due 2013	500,000	
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		72,000
Discount on senior notes	(105,904)	(95,577)
Discount for interest rate derivatives[(b)]	(88,649)	(11,349)
Total senior notes and long-term debt	$ 6,330,115	$ 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, or upon a fundamental change, at 100% of the principal amount of these notes. The notes are convertible, at the holder s option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the six-month period ending May 14, 2016, under certain conditions.

We may redeem the convertible senior notes on or after November 15, 2015 at a redemption price of 100% of the principal amount of such notes.

(b) See Note 2 for a description of these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $863.8 million is due.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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

	Notes	Loss on Repurchases/Exchanges		
	Retired	Premium	Other[(a)]	Total
For the Three Months Ended June 30, 2005:				
8.125% Senior Notes due 2011	$ 237.8	$ 16.8	$ 4.3	$ 21.1
9.0% Senior Notes due 2012	298.9	41.3	6.0	47.3
	$ 536.7	$ 58.1	$ 10.3	$ 68.4
For the Six Months Ended June 30, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9
8.125% Senior Notes due 2011	237.8	16.8	4.3	21.1
9.0% Senior Notes due 2012	298.9	41.3	6.0	47.3
	$ 547.7	$ 58.9	$ 10.4	$ 69.3

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

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 2.75% Contingent Convertible Senior Notes due 2035, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit 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; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; 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, jointly and severally, by all of our wholly owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

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 June 30, 2006, we had no outstanding borrowings under our facility and utilized $5.4 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 0.42 to 1 and our indebtedness to EBITDA ratio was 1.69 to 1 at June 30, 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.

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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.

7. Segment Information

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have 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, compressing, 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 $597.1 million, $463.9 million, $1.288 billion and $869.1 million for the Current Quarter, Prior Quarter, Current Period and Prior Period, 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 June 30, 2006:					
Revenues	$ 1,186,383	$ 964,686	$ 70,862	$ (637,915)	$ 1,584,016
Intersegment revenues		(597,076)	(40,839)	637,915	
Total revenues	$ 1,186,383	$ 367,610	$ 30,023	$	$ 1,584,016
Income before income taxes	$ 592,674	$ 7,919	$ 22,554	$ (18,465)	$ 604,682
For the Three Months Ended June 30, 2005:					
Revenues	$ 772,401	$ 739,514	$ 14,193	$ (478,090)	$ 1,048,018
Intersegment revenues		(463,897)	(14,193)	478,090	
Total revenues	$ 772,401	$ 275,617	$	$	$ 1,048,018
Income before income taxes	$ 301,188	$ 3,978	$ 2,817	$ (2,817)	$ 305,166
For the Six Months Ended June 30, 2006:					
Revenues	$ 2,697,204	$ 2,060,222	$ 120,508	$ (1,349,351)	$ 3,528,583
Intersegment revenues		(1,288,245)	(61,106)	1,349,351	
Total revenues	$ 2,697,204	$ 771,977	$ 59,402	$	$ 3,528,583

Income before income taxes	$	1,581,497	$	19,438	$	33,753	$	(24,000)	$	1,610,688
For the Six Months Ended June 30, 2005:										
Revenues	$	1,311,343	$	1,389,221	$	23,182	$	(892,278)	$	1,831,468
Intersegment revenues				(869,096)		(23,182)		892,278		
Total revenues	$	1,311,343	$	520,125	$		$		$	1,831,468
Income before income taxes	$	492,375	$	9,657	$	2,815	$	(2,815)	$	502,032
As of June 30, 2006:										
Total assets	$	19,431,406	$	542,830	$	503,930	$	(417,115)	$	20,061,051
As of December 31, 2005:										
Total assets	$	15,722,795	$	688,747	$	305,875	$	(598,955)	$	16,118,462

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

8. 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 Period ($ in millions):

Quarter	Acquired From	Location of Properties	Amount
First	Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
	Tulsa-based oil and gas company	Texas Gulf Coast and 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
Second	Dallas-based oil and gas company	Permian	375
	Oklahoma City-based oil and gas company	Permian	175
	Other	Various	196
	Total acquisitions		$ 1,739

We also recorded approximately $81.4 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 a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. In addition to the cash purchase price, we recorded approximately $17.5 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. Of the total $65.0 million purchase price, $27.1 million was allocated to tangible equipment, $11.0 million to intangibles and $26.9 million to goodwill. The amounts allocated to intangibles and goodwill are included in long-term assets in the accompanying condensed consolidated balance sheet. Goodwill is not amortized but is subject to an annual assessment of impairment. In February 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.

9. Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) 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 FASB 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 did not have a material impact on our financial statements.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a

Table of Contents

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

10. Subsequent Events

On July 11, 2006, we issued 3.75 million shares of common stock at $29.05 per share and 300,000 shares of our 6.25% mandatory convertible preferred stock upon the exercise of the underwriters options to purchase the additional shares pursuant to the June 2006 public offerings of our common stock and 6.25% preferred stock.

On July 27, 2006, we acquired a drilling contractor and affiliated trucking company in the Appalachian Basin for $70 million in cash.

On July 28, 2006, we acquired oil and natural gas properties and mid-stream natural gas systems from Four Sevens Oil Co., Ltd. and Sinclair Oil Corporation for $845 million in cash.

Table of Contents

P ART I. FINANCIAL INFORMATION

I TEM 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, other operating income and expenses for the three and six months ended June 30, 2006 (the Current Quarter and the Current Period) and the three and six months ended June 30, 2005 (the Prior Quarter and the Prior Period):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Net Production:				
Oil (mbbls)	2,143	2,012	4,259	3,758
Natural gas (mmcf)	129,818	101,128	253,874	195,259
Natural gas equivalent (mmcfe)	142,676	113,200	279,428	217,807
Oil and Natural Gas Sales ($ in thousands):				
Oil sales	$ 138,241	$ 96,798	$ 262,908	$ 176,742
Oil derivatives realized gains (losses)	(12,227)	(10,650)	(16,035)	(17,717)
Oil derivatives unrealized gains (losses)	(2,564)	10,900	(3,899)	(1,942)
Total oil sales	123,450	97,048	242,974	157,083
Natural gas sales	774,259	635,901	1,714,577	1,171,678
Natural gas derivatives realized gains (losses)	269,650	(33,702)	521,679	13,713
Natural gas derivatives unrealized gains (losses)	19,024	73,154	217,974	(31,131)
Total natural gas sales	1,062,933	675,353	2,454,230	1,154,260
Total oil and natural gas sales	$ 1,186,383	$ 772,401	$ 2,697,204	$ 1,311,343
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 64.51	$ 48.11	$ 61.73	$ 47.03
Natural gas ($ per mcf)	$ 5.96	$ 6.29	$ 6.75	$ 6.00
Natural gas equivalent ($ per mcfe)	$ 6.40	$ 6.47	$ 7.08	$ 6.19
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 58.80	$ 42.82	$ 57.97	$ 42.32
Natural gas ($ per mcf)	$ 8.04	$ 5.95	$ 8.81	$ 6.07
Natural gas equivalent ($ per mcfe)	$ 8.20	$ 6.08	$ 8.89	$ 6.17
Other Operating Income[(a)] ($ in thousands):				
Marketing	$ 11,922	$ 5,614	$ 24,929	$ 12,846
Service operations	$ 14,356	$	$ 29,298	$
Other Operating Income ($ per mcfe):				
Marketing	$ 0.08	$ 0.05	$ 0.09	$ 0.06
Service operations	$ 0.10	$	$ 0.10	$
Expenses ($ per mcfe):				
Production expenses	$ 0.85	$ 0.64	$ 0.86	$ 0.65
Production taxes	$ 0.24	$ 0.42	$ 0.32	$ 0.38
General and administrative expenses	$ 0.24	$ 0.10	$ 0.22	$ 0.11

Oil and natural gas depreciation, depletion and amortization	$ 2.30	$ 1.85	$ 2.27	$ 1.79
Depreciation and amortization of other assets	$ 0.16	$ 0.10	$ 0.17	$ 0.10
Interest expense[(b)]	$ 0.51	$ 0.48	$ 0.52	$ 0.46
Interest Expense ($ in thousands):				
Interest expense	$ 73,834	$ 54,710	$ 146,732	$ 102,003
Interest rate derivatives realized (gains) losses	(1,163)	(675)	(2,407)	(1,796)
Interest rate derivatives unrealized (gains) losses	785	(133)	1,789	(3,177)
Total interest expense	$ 73,456	$ 53,902	$ 146,114	$ 97,030
Net Wells Drilled	329	196	584	365
Net Producing Wells as of the End of the Period	18,016	9,054	18,016	9,054

(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.

26

Table of Contents

Chesapeake is currently the second largest independent producer of natural gas in the United States. We own interests in approximately 32,700 producing oil and natural gas wells that are currently producing approximately 1.6 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the U.S. east of the Rocky Mountains. Our most important operating area has historically been in various conventional plays in the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At June 30, 2006, 49% of our estimated proved oil and natural gas reserves were located in the Mid-Continent. During the past four years, we have also built significant positions in various conventional and unconventional plays 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 Texas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Fayetteville Shale in Arkansas and the Barnett and Woodford Shales in West Texas.

Oil and natural gas production for the Current Quarter was 142.7 bcfe, an increase of 29.5 bcfe, or 26% over the 113.2 bcfe produced in the Prior Quarter. We have increased our production for 20 consecutive quarters. During these 20 quarters, Chesapeake s U.S. production has increased 296% for an average compound quarterly growth rate of 7.1% and an average compound annual growth rate of 31.7%.

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 $8.20 per mcfe in the Current Quarter compared to $6.08 per mcfe in the Prior Quarter. The increase in prices resulted in an increase in revenue of $302.4 million, and increased production resulted in an increase in revenue of $179.2 million, for a total increase in revenue of $481.6 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 continued to lead the nation in drilling activity with an average utilization of 87 operated rigs and 76 non-operated rigs. Through this drilling activity, we drilled 351 (286 net) operated wells and participated in another 430 (43 net) wells operated by other companies. The company s drilling success rate was 97% for company-operated wells and 99% for non-operated wells. During the Current Quarter, Chesapeake invested $593 million in operated wells, $130 million in non-operated wells and $195 million in acquiring new 3-D seismic data and leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $752 million during the Current Quarter, including amounts paid for unproved leasehold and excluding $0.2 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 8.101 tcfe, an increase of 580 bcfe, or 7.7%. During the Current Period, we replaced 279 bcfe of production with an estimated 860 bcfe of new proved reserves, for a reserve replacement rate of 308%. Reserve replacement through the drillbit was 590 bcfe, or 211% of production (including 352 bcfe of positive performance revisions and 196 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and June 30, 2006) and 69% of the total increase. Reserve replacement through the acquisition of proved reserves was 269 bcfe, or 97% of production and 31% 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 one year.

Chesapeake attributes its strong drilling results and organic growth rates during the first half 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. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff by over 450% to nearly 800 employees. Today, the company has more than 4,100 employees, of which approximately 70% work in the company s E&P operations and 30% work in the company s oilfield service operations.

Since 2000, Chesapeake has invested $4.7 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be one of the largest inventories of onshore leasehold (9.7 million net acres) and 3-D seismic (12.9 million acres) in the U.S. On this leasehold, the company has an estimated 24,000 net drilling locations representing an approximate 10-year inventory of drilling projects.

Table of Contents

In July 2006, Chesapeake purchased a drilling contractor in the Appalachian Basin. The company is currently utilizing two of the contractor s 15 rigs and, through this acquisition, will gain enhanced operational flexibility in expanding activity levels in the basin. This acquisition bolsters the scale and operating capabilities of the company s 100% owned drilling rig subsidiary, Nomac Drilling Corporation. To date, Chesapeake has invested approximately $400 million to build or acquire 57 drilling rigs (including the recent acquisition of the Appalachian Basin drilling contractor), and is building 22 additional rigs. In total, Chesapeake s drilling rig fleet should reach 79 rigs by the end of the 2007 first quarter, which would rank Nomac as one of the six largest drilling rig contractors in the U.S.

Chesapeake s direct rig ownership is complemented by its $63 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake owns approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain owns four rigs and has ordered another six rigs for delivery later in 2006 and 2007. Chesapeake s rig investments have served as an effective 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 June 30, 2006, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 41% compared to 47% as of December 31, 2005. During the Current Period, we received net proceeds of $2.15 billion through issuances of $500 million of preferred equity, $726.3 million of common equity and $1.0 billion principal amount of senior notes. We used the net proceeds from these offerings primarily to fund the purchase price for acquisitions and to repay outstanding indebtedness under our revolving bank credit facility. As a result of our debt transactions in 2005 and the Current Period, we have extended the average maturity of our long-term debt to over nine years and have lowered our average interest rate to approximately 6.4%.

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 at some point in the future.

Liquidity and Capital Resources

Sources and Uses of Funds

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 $3.7 billion and $4.0 billion. We believe this level of exploration and development will be sufficient to increase our proved oil and natural gas reserves in 2006 and achieve our goal of an organic growth rate of 10% over 2005 production and at least a 25% 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 $2.045 billion in the Current Period compared to $1.020 billion in the Prior Period. The $1.025 billion increase was primarily due to higher realized prices and higher oil and natural gas production. 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 87% of our expected oil production for the second half of 2006 hedged at an average NYMEX price of $65.25 per barrel of oil, and 90% of our expected natural gas production for the second half of 2006 hedged at an average NYMEX price of $9.17 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. All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties

Table of Contents

mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and gas properties, rather than posting cash or letters of credit with the counterparties. As of June 30, 2006, we had outstanding collateral allocations and pledges of oil and gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our bank credit facility. As of August 4, 2006, we had outstanding transactions with thirteen counterparties, seven of which hold collateral allocations from our bank facility or liens against certain oil and gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. As of August 4, 2006, we were not required to post cash or letters of credit with the remaining four counterparties. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

A significant source of liquidity is our $2.0 billion syndicated revolving bank credit facility which matures in February 2011. At August 4, 2006, there was $1.0 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 $4.055 billion and repaid $4.127 billion in the Current Period, and we borrowed $2.419 billion and repaid $2.023 billion in the Prior Period under the credit facility. We incurred $4.1 million and $4.6 million of financing costs related to amendments to the credit facility agreement in the Current Period and the Prior Period, 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, debt service 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 to finance 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.

The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Six Months Ended June 30,			
	2006		2005	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$ 500.0	$ 484.8	$ 460.0	$ 447.2
Common stock	726.3	698.9		
Unsecured senior notes guaranteed by subsidiaries	1,000.0	969.2	1,200.0	1,180.7
Total	$ 2,226.3	$ 2,152.9	$ 1,660.0	$ 1,627.9

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 $37.0 million and $27.9 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.05 to $0.06 per share beginning with the dividend paid in July 2006. We paid dividends on our preferred stock of $38.2 million and $10.9 million in the Current Period and the Prior Period, respectively. We received $67.6 million and $11.6 million from the exercise of employee and director stock options and warrants in the Current Period and the Prior Period, respectively. The Current Period amount included $38.3 million paid by Tom L. Ward, our former President and Chief Operating Officer, to exercise all of his stock options following his resignation in February 2006.

In the Current Period, we paid $50.7 million to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

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 Period, we reported a tax benefit of $81.5 million.

29

Table of Contents

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $42.4 million and $75.2 million in the Current Period and the Prior Period, 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. The following table shows our purchases and exchanges of senior notes in the Prior Period ($ in millions):

	Senior Notes Activity			
	Retired	Premium	Other[(a)]	Cash Paid
For the Six Months Ended June 30, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$	$ 11.8
8.125% Senior Notes due 2011	237.8	16.8	0.7	255.3
9.0% Senior Notes due 2012	298.9	41.3	0.8	341.0
	$ 547.7	$ 58.9	$ 1.5	$ 608.1

(a) Includes adjustments to accrued interest and discount associated with notes retired and new notes issued, cash in lieu of fractional notes, transaction costs and fair value hedging adjustments.

Cash used in investing activities increased to $3.784 billion during the Current Period, compared to $2.540 billion during the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Six Months Ended June 30,	
	2006	2005
Oil and Natural Gas Investing Activities:		
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 447.9	$ 932.8
Acquisition of unproved properties	1,256.1	502.4
Exploration and development of oil and natural gas properties	1,289.4	832.9
Leasehold acquisitions	323.9	91.0
Geological and geophysical costs	71.7	26.6
Other oil and natural gas activities	3.8	4.1
Total oil and natural gas investing activities	3,392.8	2,389.8
Other Investing Activities:		
Additions to buildings and other fixed assets	181.1	98.4
Additions to drilling rig equipment (including Martex Drilling Company, L.L.P)	244.2	29.3
Additions to investments	38.4	22.4
Proceeds from sale of investment in Pioneer Drilling Company `	(158.9)	
Acquisition of trucking company, net of cash acquired	45.2	
Deposit for acquisitions	42.5	
Other	(1.2)	
Total other investing activities	391.3	150.1
Total cash used in (provided by) investing activities	$ 3,784.1	$ 2,539.9

Our accounts receivable are primarily from purchasers of oil and natural gas ($420.2 million at June 30, 2006) and exploration and production companies which own interests in properties we operate ($105.5 million at June 30, 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 as a source of liquidity. We are not a commercial paper issuer.

Table of Contents

Acquisitions and Financing Transactions

The following table describes investing transactions related to the acquisition of proved and unproved properties that we completed in the Current Period ($ in millions):

Quarter	Acquired From	Location of Properties	Amount
First	Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
	Tulsa-based oil and gas company	Texas Gulf Coast and 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
Second	Dallas-based oil and gas company	Permian	375
	Oklahoma City-based oil and gas company	Permian	175
	Other	Various	196
	Total oil and natural gas acquisitions		1,739
	Less cash deposits paid in 2005		(35)
	Total oil and natural gas acquisitions in the Current Period		$ 1,704

We also recorded approximately $81.4 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 a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. We recorded approximately $17.5 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. In February 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.

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 nine years with an average interest rate of approximately 6.4%. 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 Period:

First Quarter 2006

- 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.

Second Quarter 2006

Completed a public exchange of 83,245 shares of our 4.125% cumulative convertible preferred stock, representing 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, for 5.2 million shares of our common stock pursuant to a tender offer. No cash was received or paid in connection with this transaction.

Completed a public exchange of 804,048 shares of our 5.0% (Series 2003) cumulative convertible preferred stock, representing 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding, for 5.0 million shares of our common stock pursuant to a tender offer. No cash was received or paid in connection with this transaction.

Table of Contents

Completed public offerings of $500 million of 7.625% Senior Notes due 2013, 2.0 million shares of 6.25% mandatory convertible preferred stock having a liquidation preference of $250 per share, and 25 million shares of common stock at $29.05 per share. Net proceeds of approximately $1.666 billion were used to fund acquisitions, to repay borrowings under our revolving bank credit facility and for general corporate purposes.

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 June 30, 2006, we had no outstanding borrowings under this facility and had utilized $5.4 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 0.42 to 1 and our indebtedness to EBITDA ratio was 1.69 to 1 at June 30, 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. All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and gas properties, rather than posting cash or letters of credit with the counterparties. As of June 30, 2006, we had outstanding collateral allocations and pledges of oil and gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our bank credit facility. As of August 4, 2006, we had outstanding transactions with thirteen counterparties, seven of which hold collateral allocations from our bank facility or liens against certain oil and gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. We were not required to post cash or letters of credit with the remaining four counterparties, as of August 4, 2006. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

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. The hedging facilities are subject to a 1.0% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of June 30, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $108.7 million under one of the facilities and an asset of $490.7 million under the other facility. As of August 4, 2006, the fair market value of the same transactions was an asset of approximately $16.4 million and $246.5 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.

Table of Contents

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 June 30, 2006, our senior notes consisted of the following ($ in thousands):

7.5% Senior Notes due 2013	$ 363,823
7.625% Senior Notes due 2013	500,000
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	(105,904)
Discount for interest rate derivatives	(88,649)
	$ 6,330,115

No scheduled principal payments are required under our senior notes until 2013, when $863.8 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 these notes.

As of June 30, 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 in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly-owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit 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; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; 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 June 30, 2006, we estimate that secured commercial bank indebtedness of approximately $3.1 billion could have been incurred under the most restrictive indenture covenant.

Results of Operations Three Months Ended June 30, 2006 vs. June 30, 2005

General. For the Current Quarter, Chesapeake had net income of $359.9 million, or $0.82 per diluted common share, on total revenues of $1.584 billion. This compares to net income of $193.8 million, or $0.52 per diluted common share, on total revenues of $1.048 billion during the Prior Quarter.

Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.186 billion compared to $772.4 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 142.7 bcfe at a weighted average price of $8.20 per mcfe, compared to 113.2 bcfe produced in the Prior Quarter at a weighted average price of $6.08 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $16.5 million and $84.1 million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $302.4 million and increased production resulted in a $179.2 million increase, for a total increase in revenues of $481.6 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 and acquisitions completed in 2005 and 2006.

For the Current Quarter, we realized an average price per barrel of oil of $58.80, compared to $42.82 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 $8.04 and $5.95 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 $257.4 million, or $1.80 per mcfe, in the Current Quarter and a net decrease of $44.4 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 $13.0 million and $12.3 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 June 30,			
	2006		2005	
	Mmcfe	**Percent**	**Mmcfe**	**Percent**
Mid-Continent	78,208	55%	74,569	66%
Ark-La-Tex and Barnett Shale	21,179	15	12,491	11
South Texas and Texas Gulf Coast	19,357	14	16,142	14
Permian Basin	12,048	8	9,325	8
Appalachian Basin	11,225	8		
Other	659		673	1
Total Production	142,676	100%	113,200	100%

Natural gas production represented approximately 91% of our total production volume on a natural gas equivalent basis in the Current Quarter, compared to 89% in the Prior Quarter.

Marketing Sales and Operating Expenses. Marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $367.6 million in oil and natural gas marketing sales to third parties in the Current Quarter, with corresponding oil and natural gas marketing expenses of $355.7 million, for a net margin of $11.9 million. This compares to sales of $275.6 million, expenses of $270.0 million and a net margin of $5.6 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and natural gas marketing sales volumes.

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 recognized $30.0 million in service operations revenue in the Current Quarter with corresponding service operations expense of $15.7 million, for a net margin of $14.3 million principally associated with businesses acquired in the Current Period. During the Prior Quarter, we had no revenues or expenses from service operations due to the insignificant level of operations.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $120.7 million in the Current Quarter compared to $72.3 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.85 per mcfe in the Current Quarter compared to $0.64 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 the remainder of 2006 will range from $0.85 to $0.95 per mcfe produced.

Production Taxes. Production taxes were $33.9 million and $47.3 million in the Current Quarter and the Prior Quarter, respectively. On a unit-of-production basis, production taxes were $0.24 per mcfe in the Current Quarter compared to $0.42 per mcfe in the Prior Quarter. The Current Quarter included the reversal of an accrual of $11.6 million as the result of the dismissal of certain severance tax claims while the Prior Quarter included an accrual of $5.0 million associated with such severance tax claims. Excluding these items, production taxes were $0.32 per mcfe in the Current Quarter compared to $0.37 in the Prior Quarter. This decrease is the result of an increase in production tax exemptions realized in the Current Quarter. 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 the remainder of 2006 to range from $0.38 to $0.42 per mcfe based on NYMEX prices of $56.25 per barrel of oil and natural gas prices ranging from $6.80 to $7.60 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 $33.6 million in the Current Quarter and $11.8 million in the Prior Quarter. General and administrative expenses were $0.24 and $0.10 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 as well as cost and wage inflation. Our growth has resulted in a substantial increase in employees and related costs. Included in general and administrative expenses is stock-based compensation of $6.6 million and $2.5 million for the Current Quarter and Prior Quarter, respectively. We anticipate that general and administrative expenses for the remainder of 2006 will be between $0.20 and $0.27 per mcfe (including stock-based compensation ranging from $0.05 and $0.07 per mcfe).

Our stock-based compensation for employees and non-employee directors is principally in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors since July 2005. Stock-based compensation awards before 2004 (and before 2005 for non-employee directors) were in the form of stock options. These stock-based compensation awards vest over a period of four years, 25% on the anniversary date of each grant. Our non-employee director awards vest over a period of three years.

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 and non-employee director 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-date 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 $2.5 million in the Prior Quarter to $6.6 million in the Current Quarter. Of this increase, $1.2 million was due to stock option expense and $2.9 million was due to a higher number of unvested restricted shares outstanding during the Current Quarter compared to the Prior Quarter.

The discussion of stock-based compensation in note 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock, as well as the effects of our adoption of SFAS 123(R).

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 exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $34.0 million and $23.5 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 $328.2 million and $209.4 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 $2.30 and $1.85 in the Current Quarter and in the Prior Quarter, respectively. The $0.45 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 the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2006 to be between $2.35 and $2.40 per mcfe produced.

Table of Contents

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $23.2 million in the Current Quarter, compared to $11.8 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of the depreciation of recently acquired assets resulting from our acquisition of various gathering facilities and compression equipment, the 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 2006. 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 Chesapeake wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for the remainder of 2006 to be between $0.18 and $0.22 per mcfe produced.

Interest and Other Income. Interest and other income was $5.0 million in the Current Quarter compared to $2.0 million in the Prior Quarter. The Current Quarter income consisted of $0.5 million of interest income, $2.4 million related to earnings of equity investees, a $0.4 million gain on sale of assets and $1.7 million of miscellaneous income. The Prior Quarter income consisted of $0.4 million of interest income, $1.1 million related to earnings of equity investees and $0.5 million of miscellaneous income.

Interest Expense. Interest expense increased to $73.5 million in the Current Quarter compared to $53.9 million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2006	**2005**
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 110.8	$ 71.2
Capitalized interest	(38.6)	(17.9)
Amortization of loan discount	1.7	1.4
Unrealized (gain) loss on interest rate derivatives	0.8	(0.1)
Realized (gain) loss on interest rate derivatives	(1.2)	(0.7)
Total interest expense	$ 73.5	$ 53.9
Average long-term borrowings	$ 6,150	$ 3,554

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 later in Item 3 - Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.51 per mcfe in the Current Quarter compared to $0.48 per mcfe in the Prior Quarter. We expect interest expense for the remainder of 2006 to be between $0.55 and $0.59 per mcfe produced (before considering the effect of interest rate derivatives).

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

	Notes	**Loss on Repurchases/Exchanges**		
	Retired	**Premium**	**Other [(a)]**	**Total**
For the Three Months Ended June 30, 2005:				
8.125% Senior Notes due 2011	$ 237.8	$ 16.8	$ 4.3	$ 21.1
9.0% Senior Notes due 2012	298.9	41.3	6.0	47.3

$ 536.7	$ 58.1	$ 10.3	$ 68.4

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with retired notes 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 $244.8 million in the Current Quarter, compared to income tax expense of $111.4 million in the Prior Quarter. Our effective income tax rate increased to

36

Table of Contents

40.5% in the Current Quarter compared to 36.5% in the Prior Quarter. This increase included the impact that both state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas House Bill 3 was signed into law which eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. Although the new margin tax is not effective until 2007, the provisions of SFAS 109, *Accounting for Income Taxes*, require us to record the impact that this change has on our liability for deferred income taxes in the period of enactment. As a result, we recorded $15 million in additional deferred state income tax expense, net of the federal income tax benefit, in the Current Quarter. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Current Quarter. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Results of Operations Six Months Ended June 30, 2006 vs. June 30, 2005

General. For the Current Period, Chesapeake had net income of $983.6 million, or $2.27 per diluted common share, on total revenues of $3.529 billion. This compares to net income of $318.8 million, or $0.88 per diluted common share, on total revenues of $1.832 billion during the Prior Period.

Oil and Natural Gas Sales. During the Current Period, oil and natural gas sales were $2.697 billion compared to $1.311 billion in the Prior Period. In the Current Period, Chesapeake produced 279.4 bcfe at a weighted average price of $8.89 per mcfe, compared to 217.8 bcfe produced in the Prior Period at a weighted average price of $6.17 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $214.1 million and ($33.1) million in the Current Period and Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $758.3 million and increased production resulted in a $380.4 million increase, for a total increase in revenues of $1.139 billion (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Period to the Current Period is due to the combination of production growth generated from drilling as well as acquisitions completed in 2005 and the Current Period.

For the Current Period, we realized an average price per barrel of oil of $57.97 compared to $42.32 in the Prior Period (weighted average prices for both periods discussed exclude the effect of unrealized gains or losses on oil and natural gas derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.81 and $6.07 in the Current Period and Prior Period, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $505.6 million, or $1.81 per mcfe, in the Current Period and a net decrease of $4.0 million, or $0.02 per mcfe, in the Prior Period.

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 Period 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 $25.4 million and $24.1 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 $4.3 million and $4.0 million, respectively, without considering the effect of derivative activities.

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

	For the Six Months Ended June 30,			
	2006		2005	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	152,132	55%	147,381	67%
Ark-La-Tex and Barnett Shale	41,358	15	23,914	11
South Texas and Texas Gulf Coast	39,619	14	28,078	13
Permian Basin	23,510	8	17,112	8
Appalachian Basin	21,518	8		
Other	1,291		1,322	1
Total Production	279,428	100%	217,807	100%

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

Marketing Sales and Operating Expenses. Marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $772.0 million in oil and natural gas marketing sales to third parties in the Current Period, with corresponding oil and natural gas marketing expenses of $747.0 million, for a net margin of $25.0 million. This compares to sales of $520.1 million, expenses of $507.3 million and a net margin of $12.8 million in the Prior Period. In the Current Period, Chesapeake realized an increase in oil and natural gas marketing sales volumes and an increase in oil and natural gas prices.

Table of Contents

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 recognized $59.4 million in service operations revenue in the Current Period with corresponding service operations expenses of $30.1 million, for a net margin of $29.3 million principally associated with businesses acquired in the Current Period. During the Prior Period, we had no revenues or expenses from service operations due to the insignificant level of operations.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $240.1 million in the Current Period compared to $141.9 million in the Prior Period. On a unit-of-production basis, production expenses were $0.86 per mcfe in the Current Period compared to $0.65 per mcfe in the Prior Period. The increase in the Current Period 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 the remainder of 2006 will range from $0.85 to $0.95 per mcfe.

Production Taxes. Production taxes were $89.3 million and $83.2 million in the Current Period and the Prior Period, respectively. On a unit-of-production basis, production taxes were $0.32 per mcfe in the Current Period compared to $0.38 per mcfe in the Prior Period. The Current Period included a $2.1 million accrual for certain severance tax claims and then a subsequent reversal of the cumulative $11.6 million accrual for such severance tax claims as a result of their dismissal. The Prior Period included an accrual of $5.0 million associated with such severance tax claims. Excluding these items, production taxes were $0.35 per mcfe in the Current Period and $0.36 per mcfe in the Prior Period. This decrease is the result of an increase in production tax exemptions realized offset by higher oil and natural gas prices. 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 the remainder of 2006 to range from $0.38 to $0.42 per mcfe based on NYMEX prices of $56.25 per barrel of oil and natural gas prices ranging from $6.80 to $7.60 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 $62.3 million in the Current Period and $23.9 million in the Prior Period. General and administrative expenses were $0.22 and $0.11 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of the company s overall growth as well as cost and wage inflation. Our growth has resulted in a substantial increase in employees and related costs. Included in general and administrative expenses is stock-based compensation of $12.8 million and $4.9 million for the Current Period and Prior Period, respectively. We anticipate that general and administrative expenses for the remainder of 2006 will be between $0.20 and $0.27 per mcfe (including stock-based compensation ranging from $0.05 and $0.07 per mcfe).

Our stock-based compensation for employees and non-employee directors is principally in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors annually since July 2005. Stock-based compensation awards before 2004 (and before 2005 for non-employee directors) were in the form of stock options. These stock-based compensation awards vest over a period of four years, 25% on the anniversary date of each grant. Our non-employee director awards vest over a period of three years.

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 and non-employee director 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-date 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 $4.9 million in the Prior Period to $12.8 million in the Current Period. Of this increase, $2.3 million was due to stock option expense, $5.5 million was due to a higher number of unvested restricted shares outstanding during the Current Period compared to the Prior Period, and $0.1 million was due to stock granted to a new director.

Table of Contents

The discussion of stock-based compensation in note 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock, as well as the effects of our adoption of SFAS 123(R).

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 exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $68.7 million and $45.8 million of internal costs in the Current Period and the Prior Period, 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 $633.1 million and $390.3 million during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.27 and $1.79 in the Current Period and in the Prior Period, respectively. The $0.48 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2006 to be between $2.35 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $47.0 million in the Current Period, compared to $21.9 million in the Prior Period. The increase in the Current Period was primarily the result of the depreciation of recently acquired assets resulting from our acquisition of various gathering facilities and compression equipment, the 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 Period. 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 depreciation and amortization of other assets for the remainder of 2006 to be between $0.18 and $0.22 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 Period.

Interest and Other Income. Interest and other income was $14.6 million in the Current Period compared to $5.4 million in the Prior Period. The Current Period income consisted of $1.3 million of interest income, $7.3 million related to earnings of equity investees, a $3.4 million gain on sale of assets and $2.6 million of miscellaneous income. The Prior Period income consisted of $3.1 million of interest income, $1.2 million related to earnings of equity investees and $1.1 million of miscellaneous income.

Interest Expense. Interest expense increased to $146.1 million in the Current Period compared to $97.0 million in the Prior Period as follows:

	Six Months Ended June 30,	
	2006	**2005**
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 213.3	$ 133.1
Capitalized interest	(69.9)	(33.9)
Amortization of loan discount	3.3	2.8
Unrealized (gain) loss on interest rate derivatives	1.8	(3.2)
Realized (gain) loss on interest rate derivatives	(2.4)	(1.8)
Total interest expense	$ 146.1	$ 97.0
Average long-term borrowings	$ 5,953	$ 3,356

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

Table of Contents

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 later in Item 3 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 Period compared to $0.46 per mcfe in the Prior Period. We expect interest expense for the remainder of 2006 to be between $0.55 and $0.59 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investment. In the Current Period, Chesapeake sold its investment in publicly-traded 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 Period and incurred losses in connection with the transactions. The following table shows the losses related to the transactions ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
	Retired	Premium	Other [(a)]	Total
For the Six Months Ended June 30, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9
8.125% Senior Notes due 2011	237.8	16.8	4.3	21.1
9.0% Senior Notes due 2012	298.9	41.3	6.0	47.3
	$ 547.7	$ 58.9	$ 10.4	$ 69.3

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

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

Income Tax Expense. Chesapeake recorded income tax expense of $627.1 million in the Current Period, compared to income tax expense of $183.2 million in the Prior Period. Our effective income tax rate increased to 38.9% in the Current Period compared to 36.5% in the Prior Period. This increase included the impact that both state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas House Bill 3 was signed into law which eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. Although the new margin tax is not effective until 2007, the provisions of SFAS 109, *Accounting for Income Taxes*, require us to record the impact that this change has on our liability for deferred income taxes in the period of enactment. As a result, we recorded $15 million in additional deferred state income tax expense, net of the federal income tax benefit, in the Current Period. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Current Period. 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 (FASB) 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 FASB 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.

Table of Contents

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 did not have a material impact on our financial statements.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

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. Our estimates of operating expenses per mcfe of projected 2006 production do not take into account possible curtailments we might experience as a result of high natural gas pipeline pressures and/or early filling of natural gas storage facilities.

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 June 30, 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, which have negative differentials to NYMEX, 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, which have positive differentials to NYMEX, 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, 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 June 30, 2006, the fair value of our basis protection swaps was $244.3 million. As of June 30, 2006, our Mid-Continent basis protection swaps covered approximately 25% of our anticipated Mid-Continent natural gas production remaining in 2006, 25% in 2007, 20% in 2008 and 14% in 2009. As of June 30, 2006, our Appalachian Basin basis protection swaps cover approximately 65% of our anticipated Appalachian Basin natural gas production in 2007, 61% in 2008 and 28% 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 $257.4 million, ($44.4) million, $505.6 million and ($4.0) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, 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 $16.5 million, $84.1 million, $214.1 million and ($33.1) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, 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 $65.6 million, $1.2 million, $164.9 million and $0.6 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Table of Contents

As of June 30, 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 June 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 ($ in thousands)	Fair Value at June 30, 2006 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
3Q 2006	107,780,000	$ 8.95	$	$	$	Yes	$	$ 305,360
4Q 2006	104,745,000	9.69				Yes		157,795
1Q 2007	100,350,000	11.09				Yes		71,420
2Q 2007	78,715,000	9.18				Yes		70,841
3Q 2007	79,580,000	9.24				Yes		59,222
4Q 2007	79,580,000	9.90				Yes		26,495
1Q 2008	64,610,000	10.84				Yes		3,819
2Q 2008	64,610,000	8.45				Yes		41,113
3Q 2008	65,320,000	8.51				Yes		33,097
4Q 2008	65,320,000	9.15				Yes		4,999
1Q 2009	900,000	10.53				Yes		255
2Q 2009	910,000	8.29				Yes		826
3Q 2009	920,000	8.34				Yes		709
4Q 2009	920,000	8.95				Yes		295
Basis Protection Swaps (Mid-Continent):								
3Q 2006	31,280,000				(0.31)	No		14,806
4Q 2006	33,720,000				(0.32)	No		31,355
1Q 2007	32,850,000				(0.29)	No		36,212
2Q 2007	34,125,000				(0.35)	No		21,429
3Q 2007	34,500,000				(0.35)	No		18,543
4Q 2007	35,720,000				(0.32)	No		30,006
1Q 2008	33,215,000				(0.30)	No		27,450
2Q 2008	26,845,000				(0.25)	No		14,426
3Q 2008	27,140,000				(0.25)	No		12,448
4Q 2008	31,410,000				(0.28)	No		17,469
1Q 2009	26,100,000				(0.32)	No		12,166
2Q 2009	20,020,000				(0.28)	No		3,836
3Q 2009	20,240,000				(0.28)	No		3,016
4Q 2009	20,240,000				(0.28)	No		6,308
Basis Protection Swaps (Appalachian Basin):								
1Q 2007	9,000,000				0.34	No		(496)
2Q 2007	9,100,000				0.34	No		(59)
3Q 2007	9,200,000				0.34	No		(43)
4Q 2007	9,200,000				0.34	No		(502)
1Q 2008	9,100,000				0.34	No		(1,278)
2Q 2008	9,100,000				0.35	No		(400)
3Q 2008	9,200,000				0.35	No		(410)
4Q 2008	9,200,000				0.35	No		(685)
1Q 2009	4,500,000				0.31	No		(617)
2Q 2009	4,550,000				0.31	No		(190)

3Q 2009	4,600,000			0.31	No	(177)
4Q 2009	4,600,000			0.31	No	(344)
Cap-Swaps:						
3Q 2006	11,960,000	6.85	5.13		No	3,525
4Q 2006	11,960,000	6.89	5.13		No	(20,659)
1Q 2007	9,900,000	11.47	5.89		No	1,464
2Q 2007	14,560,000	9.73	6.08		No	2,549
3Q 2007	14,720,000	9.92	6.08		No	(288)
4Q 2007	14,720,000	10.62	6.08		No	(4,731)
1Q 2008	15,470,000	11.47	6.22		No	(9,414)
2Q 2008	15,470,000	10.23	6.22		No	5,059
3Q 2008	15,640,000	10.30	6.22		No	2,686
4Q 2008	15,640,000	10.74	6.22		No	(3,837)
Counter Swaps:						
3Q 2006	(1,840,000)	(5.33)			No	1,450
4Q 2006	(1,840,000)	(5.50)			No	4,949

44

Table of Contents

	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 ($ in thousands)	Fair Value at June 30, 2006 ($ in thousands)
Call Options:								
3Q 2006	1,840,000			12.50		No	1,932	(9)
4Q 2006	1,840,000			12.50		No	1,932	(703)
1Q 2007	6,300,000			11.58		No	1,890	(9,512)
2Q 2007	6,370,000			9.96		No	1,911	(5,093)
3Q 2007	6,440,000			10.04		No	1,932	(6,623)
4Q 2007	6,440,000			10.56		No	1,932	(10,153)
1Q 2008	1,820,000			12.50		No	1,911	(3,073)
2Q 2008	1,820,000			12.50		No	1,911	(645)
3Q 2008	1,840,000			12.50		No	1,932	(881)
4Q 2008	1,840,000			12.50		No	1,932	(1,975)
Locked Swaps:								
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							19,215	943,565
Oil (bbls):								
Swaps:								
3Q 2006	1,487,000	64.46				Yes		(15,507)
4Q 2006	1,564,000	64.76				Yes		(17,657)
1Q 2007	1,260,000	67.38				Yes		(11,330)
2Q 2007	1,001,000	69.46				Yes		(6,726)
3Q 2007	1,012,000	69.14				Yes		(6,674)
4Q 2007	1,012,000	68.73				Yes		(6,520)
1Q 2008	910,000	69.97				Yes		(4,105)
2Q 2008	910,000	69.56				Yes		(3,873)
3Q 2008	920,000	69.15				Yes		(3,714)
4Q 2008	920,000	68.79				Yes		(3,418)
1Q 2009	45,000	66.64				Yes		(227)
2Q 2009	45,500	66.27				Yes		(223)
3Q 2009	46,000	65.92				Yes		(217)
4Q 2009	46,000	65.56				Yes		(213)
Cap-Swaps:								
3Q 2006	138,000	57.82	40.67			No		(2,358)
4Q 2006	92,000	56.53	40.00			No		(1,822)
1Q 2007	90,000	73.06	45.00			No		(300)
2Q 2007	91,000	73.06	45.00			No		(283)
3Q 2007	92,000	73.06	45.00			No		(252)
4Q 2007	92,000	73.06	45.00			No		(210)
1Q 2008	91,000	72.24	45.00			No		(230)
2Q 2008	91,000	72.24	45.00			No		(186)
3Q 2008	92,000	72.24	45.00			No		(151)
4Q 2008	92,000	72.24	45.00			No		(67)

Total Oil		(86,263)
Total Natural Gas and Oil	$ 19,215	$ 857,302

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 June 30, 2006.

Based upon the market prices at June 30, 2006, we expect to transfer approximately $364.3 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 June 30, 2006 are expected to mature by December 31, 2009.

Table of Contents

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, 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	1,913,777
Fair value of contracts when entered into during the period	(32,300)
Contracts realized or otherwise settled during the period	(505,643)
Fair value of contracts outstanding, as of June 30	$ 430,020

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 our acquisition of Columbia Natural Resources, LLC in November 2005. 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, *Amendment 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 June 30, 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 June 30, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
3Q 2006	10,626,000	$ 4.86	$	$	Yes	$ (13,382)
4Q 2006	10,626,000	4.86			Yes	(34,595)
1Q 2007	10,350,000	4.82			Yes	(55,646)
2Q 2007	10,465,000	4.82			Yes	(34,517)
3Q 2007	10,580,000	4.82			Yes	(36,574)
4Q 2007	10,580,000	4.82			Yes	(46,556)

1Q 2008	9,555,000	4.68	Yes	(53,329)
2Q 2008	9,555,000	4.68	Yes	(26,996)
3Q 2008	9,660,000	4.68	Yes	(28,549)
4Q 2008	9,660,000	4.66	Yes	(37,506)
1Q 2009	4,500,000	5.18	Yes	(19,734)
2Q 2009	4,550,000	5.18	Yes	(8,558)
3Q 2009	4,600,000	5.18	Yes	(9,262)
4Q 2009	4,600,000	5.18	Yes	(13,166)

Table of Contents

	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 June 30, 2006 ($ in thousands)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(3,543)
2Q 2009	910,000		4.50	6.00	Yes	(1,457)
3Q 2009	920,000		4.50	6.00	Yes	(1,590)
4Q 2009	920,000		4.50	6.00	Yes	(2,322)
Total Natural Gas						$ (427,282)

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of June 30, 2006, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	2006	2007	2008	2009	2010	Years of Maturity Thereafter ($ in billions)	Total	Fair Value
Liabilities:								
Long-term debt fixed-rate[(a)]	$	$	$	$	$	$ 6.525	$ 6.525	$ 6.242
Average interest rate						6.4%	6.4%	6.4%
Long-term debt variable rate	$	$	$	$	$	$	$	$
Average interest rate								

(a) This amount does not include the discount included in long-term debt of ($105.9) million and the discount for interest rate swaps of ($88.6) 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. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were $1.2 million, $0.7 million, $2.4 million and $1.8 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value 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 interest expense. Unrealized gains (losses) included in interest expense were ($0.8) million, $0.1 million, ($1.8) million and $3.2 million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

47

Table of Contents

As of June 30, 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	$ (5,308)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(10,900)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(11,193)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(15,016)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(9,590)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(16,012)
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points	(11,478)
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points	(7,276)
March 2006 August 2017	$ 250,000,000	6.500%	6 month LIBOR plus 125.5 basis points	(10,435)
April 2006 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 35.5 basis points	(5,316)
				$ (102,524)

In the Current Period, 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, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. 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.

P ART II. OTHER INFORMATION

I tem 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 June 30, 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)]
April 1, 2006 through April 30, 2006	50,094	$ 32.762		
May 1, 2006 through May 31, 2006	2,754,179	31.823		
June 1, 2006 through June 30, 2006	41,154	30.278		
Total	2,845,427	$ 31.817		

(a) Includes 1,109,694 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the company of 4,498 shares of common stock to pay the exercise price in connection with the exercise of employee stock options, the surrender to the company of 23,764 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock and 1,707,471 shares purchased in the open market to fund Chesapeake s obligation to deliver treasury shares upon the exercise of stock options under the 2000 and 2001 executive officer stock option plans.

(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.

During the six months ended June 30, 2006, we acquired shares of our 5% Convertible Preferred Stock (Series 2003) through exchanges for our common stock, as shown in the following table:

Period	Total Number	Average	Total Number of	Maximum Number

	of Shares Purchased	Price Paid Per Share[(a)]	Shares Purchased as Part of Publicly Announced Plans or Programs	of Shares That May Yet Be Purchased Under the Plans or Programs
January 1, 2006 through January 31, 2006	183,273(b)	6.22		
February 1, 2006 through February 28, 2006				
March 1, 2006 through March 31, 2006				
Total	183,273	6.22		
April 1, 2006 through April 30, 2006				
May 1, 2006 through May 31, 2006				
June 1, 2006 through June 30, 2006	804,048(c)	6.18		
Total	804,048	6.18		

(a) Represents the average number of shares of common stock issued in full consideration for each share of preferred stock acquired.
(b) Represents shares acquired through unsolicited exchange transactions with individual holders.
(c) Represents shares acquired through an offer to exchange to all holders.

Table of Contents

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

Not applicable.

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

Three matters were submitted to a vote of the shareholders at Chesapeake s annual meeting of shareholders held on June 9, 2006: (1) the election of three directors for three-year terms expiring in 2009; (2) approval of an amendment to the company s certificate of incorporation to increase the number of authorized shares of common stock; and (3) approval of an amendment to the company s Long Term Incentive Plan covering awards of stock-based compensation to its employees, consultants and non-employee directors, including an increase in the number of shares of common stock available for awards under the plan.

In the election of directors, Richard K. Davidson received 334,940,573 votes for election and 6,753,390 votes were withheld from voting for Mr. Davidson; Breene M. Kerr received 329,613,449 votes for election and 12,080,515 votes were withheld from voting for Mr. Kerr; and Charles T. Maxwell received 332,857,393 votes for election and 8,836,571 votes were withheld from voting for Mr. Maxwell. There were no broker non-votes for the election of directors. The other directors whose terms continue after the meeting are Frank A. Keating and Frederick B. Whittemore, whose terms expire in 2007, and Donald L. Nickles and Aubrey K. McClendon, whose terms expire in 2008.

On the proposal to approve the amendment to the certificate of incorporation, 328,171,206 votes were received for approval of the amendment, 9,383,151 votes were received against approval of the amendment and holders of 2,571,851 shares abstained from voting on this proposal. There were 1,567,755 broker non-votes on this proposal.

On the proposal to approve an amendment of the Long Term Incentive Plan, 196,419,509 votes were received for approval of the amendment, 12,624,510 votes were received against approval of the amendment and holders of 2,724,542 shares abstained from voting on this proposal. There were 129,925,402 broker non-votes on this proposal.

I tem 5. ***Other Information***

Not applicable.

Table of Contents

Item 6. ***Exhibits***

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

Exhibit Number	Description
3.1.1*	Restated Certificate of Incorporation, as amended.
3.1.2*	Certificate of Designations of Series A Junior Participating Preferred Stock, as amended.
3.1.3*	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended.
3.1.4*	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.
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 filed November 9, 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.
3.1.8	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed June 30, 2006.
4.1.1*	Seventh Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2.1*	Seventh Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3.1*	Eleventh Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.75% senior notes due 2015.
4.6.1*	Tenth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.
4.7.1*	Eighth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.
4.8.1*	Sixth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.

Table of Contents

4.9.1*	Fourth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.
4.10.1*	Third Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
4.11.1*	Fourth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.
4.12.1*	Third Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.
4.13.1*	Third Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.
4.14	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.625% Senior Notes due 2013. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s current report on Form 8-K filed June 30, 2006.
10.1.18	Chesapeake s Long Term Incentive Plan, as amended. Incorporated herein by reference to Exhibit 99.1 to Chesapeake s registration statement on Form S-8 (file no. 333-135949) filed July 21, 2006.
10.2.1	Fifth Amended and Restated Employment Agreement dated as of July 1, 2006, between Aubrey K. McClendon and Chesapeake. Incorporated herein by reference to Exhibit 10.2.1 to Chesapeake s current report on Form 8-K filed June 15, 2006.
10.2.10 *	Employment Agreement dated as of July 1, 2003, between J. Mark Lester and Chesapeake Energy Corporation.
10.2.11 *	Employment Agreement dated as of July 1, 2003, between Douglas J. Jacobson and Chesapeake Energy Corporation.
10.2.12 *	Employment Agreement dated as of July 1, 2003, between Henry J. Hood and Chesapeake Energy Corporation.
10.4 *	Non-Employee Director Compensation.
10.5 *	Named Executive Officer Compensation.
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.

---

* Filed herewith.
Management contract or compensatory plan or arrangement

Table of Contents

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: August 9, 2006

Table of Contents

INDEX TO EXHIBITS

Exhibit Number	Description
3.1.1*	Restated Certificate of Incorporation, as amended.
3.1.2*	Certificate of Designations of Series A Junior Participating Preferred Stock, as amended.
3.1.3*	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended.
3.1.4*	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.
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 filed November 9, 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.
3.1.8	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed June 30, 2006.
4.1.1*	Seventh Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2.1*	Seventh Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3.1*	Eleventh Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.75% senior notes due 2015.
4.6.1*	Tenth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.
4.7.1*	Eighth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.
4.8.1*	Sixth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.
4.9.1*	Fourth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.

4.10.1*	Third Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
4.11.1*	Fourth Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.
4.12.1*	Third Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.
4.13.1*	Third Supplemental Indenture dated as of May 8, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.
4.14	Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.625% Senior Notes due 2013. Incorporated herein by reference to Exhibit 4.1 to Chesapeake s current report on Form 8-K filed June 30, 2006.
10.1.18	Chesapeake s Long Term Incentive Plan, as amended. Chesapeake s Long Term Incentive Plan, as amended. Incorporated herein by reference to Exhibit 99.1 to Chesapeake s registration statement on Form S-8 (file no. 333-135949) filed July 21, 2006.
10.2.1	Fifth Amended and Restated Employment Agreement dated as of July 1, 2006, between Aubrey K. McClendon and Chesapeake. Incorporated herein by reference to Exhibit 10.2.1 to Chesapeake s current report on Form 8-K filed June 15, 2006.
10.2.10 *	Employment Agreement dated as of July 1, 2003, between J. Mark Lester and Chesapeake Energy Corporation.
10.2.11 *	Employment Agreement dated as of July 1, 2003, between Douglas J. Jacobson and Chesapeake Energy Corporation.
10.2.12 *	Employment Agreement dated as of July 1, 2003, between Henry J. Hood and Chesapeake Energy Corporation.
10.4 *	Non-Employee Director Compensation.
10.5 *	Named Executive Officer Compensation.
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.

* Filed herewith.
Management contract or compensatory plan or arrangement