CHESAPEAKE ENERGY CORP
Form 10-Q
November 10, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended September 30, 2008

¨ **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, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer , accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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 November 6, 2008, there were 600,951,146 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2008

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2008	December 31, 2007
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 1,964	$ 1
Accounts receivable	1,330	1,074
Short-term derivative instruments	463	203
Inventory	292	87
Other	62	31
Total Current Assets	4,111	1,396
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	28,498	27,656
Unevaluated properties	11,135	5,641
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(8,618)	(7,112)
Total natural gas and oil properties, at cost based on full-cost accounting	31,015	26,185
Other property and equipment:		
Natural gas gathering systems and treating plants	2,043	1,135
Buildings and land	1,393	816
Drilling rigs and equipment	246	106
Natural gas compressors	136	63
Other	426	327
Less: accumulated depreciation and amortization of other property and equipment	(414)	(295)
Total Other Property and Equipment	3,830	2,152
Total Property and Equipment	34,845	28,337
OTHER ASSETS:		
Investments	603	612
Long-term derivative instruments	157	4
Other assets	302	385
Total Other Assets	1,062	1,001
TOTAL ASSETS	$ 40,018	$ 30,734

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	September 30, 2008	December 31, 2007
	($ in millions)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,564	$ 1,262
Accrued liabilities	846	712
Short-term derivative instruments	123	174
Revenues and royalties due others	647	433
Income taxes payable	171	5
Deferred income tax liability	99	
Accrued interest	151	175
Total Current Liabilities	3,601	2,761
LONG-TERM LIABILITIES:		
Long-term debt, net	14,345	10,950
Deferred income tax liability	4,690	3,966
Asset retirement obligation	260	236
Long-term derivative instruments	570	408
Revenues and royalties due others	41	42
Other liabilities	104	241
Total Long-Term Liabilities	20,010	15,843
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
4.50% cumulative convertible preferred stock, 2,558,900 and 3,450,000 shares issued and outstanding as of September 30, 2008 and December 31, 2007, entitled in liquidation to $256 million and $345 million, respectively	256	345
5.00% cumulative convertible preferred stock (series 2005B), 2,095,615 and 5,750,000 shares issued and outstanding as of September 30, 2008 and December 31, 2007, respectively, entitled in liquidation to $209 million and $575 million, respectively	209	575
6.25% mandatory convertible preferred stock, 143,768 shares issued and outstanding as of September 30, 2008 and December 31, 2007, entitled in liquidation to $36 million	36	36
4.125% cumulative convertible preferred stock, 3,033 and 3,062 shares issued and outstanding as of September 30, 2008 and December 31, 2007, respectively, entitled in liquidation to $3 million	3	3
5.00% cumulative convertible preferred stock (series 2005), 5,000 shares issued and outstanding as of September 30, 2008 and December 31, 2007, entitled in liquidation to $1 million	1	1
Common Stock, $.01 par value, 750,000,000 shares authorized, 581,895,542 and 511,648,217 shares issued at September 30, 2008 and December 31, 2007, respectively	6	5
Paid-in capital	10,257	7,032
Retained earnings	5,604	4,150
Accumulated other comprehensive income (loss), net of tax of ($26) million and $6 million, respectively	44	(11)
Less: treasury stock, at cost; 586,779 and 500,821 common shares as of September 30, 2008 and December 31, 2007, respectively	(9)	(6)

Total Stockholders Equity	16,407	12,130
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 40,018	$ 30,734

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	($ in millions except per share data)			
REVENUES:				
Natural gas and oil sales	$ 6,408	$ 1,492	$ 5,587	$ 4,164
Natural gas and oil marketing sales	1,038	501	2,934	1,446
Service operations revenue	45	34	127	101
Total Revenues	7,491	2,027	8,648	5,711
OPERATING COSTS:				
Production expenses	239	165	658	461
Production taxes	87	56	250	151
General and administrative expenses	108	62	288	168
Natural gas and oil marketing expenses	1,014	483	2,864	1,394
Service operations expense	37	23	104	67
Natural gas and oil depreciation, depletion and amortization	480	479	1,518	1,314
Depreciation and amortization of other assets	48	44	125	120
Total Operating Costs	2,013	1,312	5,807	3,675
INCOME FROM OPERATIONS	5,478	715	2,841	2,036
OTHER INCOME (EXPENSE):				
Interest and other income (expense)	(2)	1	(13)	12
Interest expense	(48)	(116)	(212)	(279)
Loss on repurchase of Chesapeake debt	(31)		(31)	
Consent solicitation fees	(10)		(10)	
Gain on sale of investments				83
Total Other Income (Expense)	(91)	(115)	(266)	(184)
INCOME BEFORE INCOME TAXES	5,387	600	2,575	1,852
INCOME TAX EXPENSE:				
Current	193	9	196	19
Deferred	1,881	219	795	685
Total Income Tax Expense	2,074	228	991	704
NET INCOME	3,313	372	1,584	1,148
PREFERRED STOCK DIVIDENDS	(6)	(26)	(27)	(77)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK	(25)		(67)	
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 3,282	$ 346	$ 1,490	$ 1,071
EARNINGS PER COMMON SHARE:				

Basic	$ 5.93	$ 0.76	$ 2.85	$ 2.37
Assuming dilution	$ 5.61	$ 0.72	$ 2.73	$ 2.23
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.0675	$ 0.2175	$ 0.195
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	554	454	523	452
Assuming dilution	588	517	557	516

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2008	2007
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 1,584	$ 1,148
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,643	1,434
Deferred income taxes	795	685
Unrealized (gains) losses on derivatives	(89)	126
Realized (gains) losses on financing derivatives	59	(76)
Stock-based compensation	100	59
Loss from equity investments	34	
Loss on repurchase of Chesapeake debt	31	
Gain on sale of investment		(83)
Other	6	6
Change in assets and liabilities	142	90
Cash provided by operating activities	4,305	3,389
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(4,641)	(3,770)
Acquisitions of natural gas and oil companies, proved and unproved properties and leasehold, net of cash acquired	(7,589)	(2,331)
Proceeds from sale of volumetric production payment	1,210	
Divestitures of proved and unproved properties and leasehold	4,666	
Additions to other property and equipment	(1,969)	(1,005)
Additions to investments	(61)	(7)
Proceeds from sale of drilling rigs and equipment	46	322
Proceeds from sale of compressors	114	147
Sale of other assets	21	32
Proceeds from sale of investments	2	124
Cash used in investing activities	(8,201)	(6,488)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facility borrowings	12,831	5,949
Payments on credit facility borrowings	(11,307)	(4,177)
Proceeds from issuance of senior notes, net of offering costs	2,136	1,607
Proceeds from issuance of common stock, net of offering costs	2,598	
Cash paid to repurchase Chesapeake debt	(312)	
Cash paid for common stock dividends	(106)	(85)
Cash paid for preferred stock dividends	(29)	(78)
Derivative settlements	(146)	(65)
Net increase (decrease) in outstanding payments in excess of cash balance	210	(54)
Excess tax benefit from stock-based compensation	42	13
Cash received from exercise of stock options	8	8
Other financing costs	(66)	(20)

Cash provided by financing activities		5,859		3,098
Net increase (decrease) in cash and cash equivalents		1,963		(1)
Cash and cash equivalents, beginning of period		1		3
Cash and cash equivalents, end of period	$	1,964	$	2

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	($ in millions)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 215	$ 274
Income taxes, net of refunds received	$ 5	$ 33
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

As of September 30, 2008 and 2007, dividends payable on our common and preferred stock were $48 million and $56 million, respectively.

For the nine months ended September 30, 2008 and 2007, natural gas and oil properties were adjusted by $13 million and $130 million, respectively, for income tax liabilities related to acquisitions.

For the nine months ended September 30, 2008 and 2007, natural gas and oil properties were adjusted by ($3) million and $103 million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

For the nine months ended September 30, 2008 and 2007, other property and equipment were adjusted by $88 million and ($6) million, respectively, as a result of an increase (decrease) in accrued costs.

We recorded non-cash asset additions to natural gas and oil properties of $6 million and $15 million for the nine months ended September 30, 2008 and 2007, respectively, for asset retirement obligations.

We recorded non-cash asset additions to natural gas gathering systems of $6 million and $0 for the nine months ended September 30, 2008 and 2007, respectively, for asset retirement obligations.

For the nine months ended September 30, 2008, a holder of our 4.5% cumulative convertible preferred stock exchanged 891,100 shares for 2,227,750 shares of common stock in a privately negotiated exchange.

For the nine months ended September 30, 2008, holders of our 5.0% (Series 2005B) cumulative convertible preferred stock exchanged 3,654,385 shares for 10,443,642 shares of common stock in privately negotiated exchanges.

For the nine months ended September 30, 2008, holders of our 4.125% cumulative convertible preferred stock converted 29 shares into 1,743 shares of common stock, and for the nine months ended September 30, 2007, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock.

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Nine Months Ended September 30, 2008	2007
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 960	$ 1,958
Exchange of common stock for 3,654,385 shares of 5.00% preferred stock (series 2005B)	(366)	
Exchange of common stock for 891,100 shares of 4.50% preferred stock	(89)	
Exchange of common stock for 29 shares and 3 shares of 4.125% preferred stock		
Balance, end of period	505	1,958
COMMON STOCK:		
Balance, beginning of period	5	5
Issuance of 23,000,000 and 28,750,000 shares of common stock in 2008	1	
Exchange of 12,673,135 and 180 shares of common stock for preferred stock		
Balance, end of period	6	5
PAID-IN CAPITAL:		
Balance, beginning of period	7,032	5,873
Issuance of 23,000,000 shares of common stock	1,052	
Issuance of 28,750,000 shares of common stock	1,646	
Stock-based compensation	124	82
Exercise of stock options	8	8
Offering expenses	(101)	
Exchange of 12,673,135 and 180 shares of common stock for preferred stock	454	
Tax benefit from exercise of stock options and restricted stock	42	13
Balance, end of period	10,257	5,976
RETAINED EARNINGS:		
Balance, beginning of period	4,150	2,913
Net income	1,584	1,148
Dividends on common stock	(115)	(88)
Dividends on preferred stock	(15)	(77)
Adoption of FIN 48		(4)
Balance, end of period	5,604	3,892
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(11)	528
Hedging activity	54	(334)
Marketable securities activity	1	(15)
Balance, end of period	44	179

TREASURY STOCK COMMON:		
Balance, beginning of period	(6)	(26)
Purchase of 87,056 shares for company benefit plans	(3)	
Release of 1,098 and 665,673 shares for company benefit plans		20
Balance, end of period	(9)	(6)
TOTAL STOCKHOLDERS EQUITY	$ 16,407	$ 12,004

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	($ in millions)			
Net income	$ 3,313	$ 372	$ 1,584	$ 1,148
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $728 million, $68 million, ($105) million and $3 million	1,187	110	(170)	6
Reclassification of (gain) loss on settled contracts, net of income taxes of $65 million, ($65) million, $117 million and ($243) million	104	(106)	189	(398)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($29) million, $11 million, $20 million and $35 million	(46)	17	34	57
Unrealized (gain) loss on marketable securities, net of income taxes of ($16) million, ($8) million, $1 million and ($9) million	(27)	(13)	1	(15)
Comprehensive income	$ 4,531	$ 380	$ 1,638	$ 798

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited 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 annual report on Form 10-K for the year ended December 31, 2007 (2007 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 nine months ended September 30, 2008 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and nine months ended September 30, 2008 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2007 (the Prior Quarter and the Prior Period , respectively).

Income Taxes

Chesapeake adopted the provisions of FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109* on January 1, 2007. As of September 30, 2008, the company estimates we have uncertain tax positions which could result in AMT liabilities of $140 million. If the outcome of these uncertain tax positions results in AMT liabilities, they can be utilized as credits against future regular tax liabilities; therefore, we are only required to establish an interest accrual associated with these liabilities. The uncertain tax positions identified would not have an effect on the effective tax rate. At September 30, 2008, we had a liability of $11 million for interest related to these same uncertain tax positions. Chesapeake recognizes interest related to uncertain tax positions in interest expense. Penalties, if any, related to uncertain tax positions would be recorded in other expenses.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil 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 2007 Form 10-K.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Financial Instruments and Hedging Activities

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options, put options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil 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.

Basis protection swaps are arrangements that guarantee a price differential for natural gas or oil from a specified delivery point. For Mid-Continent basis protection swaps, which typically 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 typically 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 knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

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.

For call options, Chesapeake receives a 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.

For put options, Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put 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.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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. Generally, 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 natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

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

Gains or losses from certain derivative transactions are reflected as adjustments to natural gas and oil sales on the condensed consolidated statements of operations. Realized gains (losses) are included in natural gas and oil sales in the month of related production. 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 natural gas and oil sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows 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 currently recognized in natural gas and oil sales as unrealized gains (losses). The components of natural gas and oil sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	($ in millions)			
Natural gas and oil sales	$ 2,036	$ 1,161	$ 5,961	$ 3,361
Realized gains (losses) on natural gas and oil derivatives	(246)	286	(454)	916
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	4,543	73	134	(21)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	75	(28)	(54)	(92)
Total natural gas and oil sales	$ 6,408	$ 1,492	$ 5,587	$ 4,164

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The estimated fair values of our natural gas and oil derivative instruments as of September 30, 2008 and December 31, 2007 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	Nine Months Ended September 30, 2008	December 31, 2007
	($ in millions)	
Derivative assets (liabilities)[a]:		
Fixed-price natural gas swaps	$ 412	$ (54)
Natural gas basis protection swaps	127	151
Fixed-price natural gas knockout swaps	409	108
Natural gas call options	(303)	(230)
Natural gas put options	(10)	
Fixed-price natural gas collars	(49)	4
Fixed-price oil swaps	(39)	(110)
Fixed-price oil knockout swaps	(309)	(125)
Fixed-price oil cap-swaps	(6)	(17)
Oil call options	(182)	(96)
Fixed-price oil collars	(4)	
Estimated fair value	$ 46	$ (369)

(a) See Item 3. *Quantitative and Qualitative Disclosures About Market Risk* in Part I. of this report for additional information concerning any associated premiums received, or discounts paid, in connection with certain derivative transactions.

Based upon the market prices at September 30, 2008, we expect to transfer approximately $163 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of September 30, 2008 are expected to mature by December 31, 2022.

We have six 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 a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 or 1.5 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet any additional collateral coverage requirements. The hedging facilities are subject to a per annum exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. 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. The fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities[a]					
	#1	#2	#3	#4	#5	#6

	($ in millions)					
Fair value of outstanding transactions, as of September 30, 2008	$ 88	$ (91)	$ (160)	$ (9)	$ 203	$ (195)
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2013	2020	2012	2012	2012

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 6.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 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.

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 ($5) million, $1 million, ($1) million and a nominal amount in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Unrealized gains (losses) included in interest expense were $8 million, ($19) million, $9 million and ($13) million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

As of September 30, 2008, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:							
January 2008 November 2020	$ 1,400	6.81%	6 month LIBOR plus 257 basis points		Yes	$	$ (30)
January 2008 January 2018	$ 500	6.94%	6 month LIBOR plus 290 basis points		No	2	(6)
Floating to Fixed Swaps:							
August 2007 August 2010	$ 825	4.74%	1 - 3 month LIBOR		No		(14)
Swaption:							
July 2008 October 2008	$ 250	6.50%			No	4	(6)
Call Options:							
January 2008 July 2010	$ 1,000	6.63%			No	9	(18)
Collars:							
August 2007 August 2010	$ 800			5.37% 4.52%	No		(19)
						$ 15	$ (93)

In the Current Period, we sold call options on five of our interest rate swaps and received $12 million in premiums. Three call options were exercised in the Current Period resulting in the termination of three interest rate swaps and one call option expired unexercised. Additionally, we sold two swaptions in the Current Period and received $6 million in net premiums. One swaption was exercised during the Current Period and resulted in a new interest rate swap.

In the Current Period, we closed 32 interest rate swaps for gains totaling $72 million. These interest rate swaps were designated as fair value hedges and the settlement amounts received will be amortized as a reduction to interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($845 million at September 30, 2008) using an exchange rate of $1.4081 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $27 million at September 30, 2008.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in both cash and cash equivalents and derivative instruments. On September 30, 2008, our cash and cash equivalents were invested in money market funds with investment grade ratings. A significant portion of these funds was invested at the close of business on September 19, 2008, and is protected under the U.S. Treasury Department s Temporary Guarantee Program. The remaining funds were spread among several counterparties to mitigate the risk. The derivative instruments enable us to hedge a portion of our exposure to natural gas and oil price and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment-grade rated counterparties deemed by management to be competent and competitive market makers. Recently there have been concerns about the ability of certain counterparties to continue to meet their financial obligations. On September 30, 2008, our commodity and interest rate derivative instruments were spread among 19 counterparties and no single counterparty represented a material credit risk to the company.

On September 15, 2008, Lehman Brothers Holdings Inc. (Lehman) filed for protection under Chapter 11 of the federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. Chesapeake and its subsidiaries had certain business relationships with Lehman and its subsidiaries. We believe the Lehman bankruptcy and its potential impact on subsidiaries of Lehman will not have a material adverse effect on Chesapeake or its subsidiaries individually or collectively.

Lehman Brothers Commercial Bank (LBCB), a subsidiary of Lehman, had $75 million (2.1%) of the $3.5 billion in commitments under our revolving bank credit facility. Although LBCB, to date, has not filed for bankruptcy (to our knowledge), LBCB has not funded approximately $11 million of its share of our borrowings under the credit facility and we have no reason to expect that LBCB will do so in the future. The loss of $11 million in borrowing capacity is not material to us.

Chesapeake was a counterparty with Lehman Brothers Commodity Services Inc. (LBCS), a subsidiary of Lehman, in financial transactions. Specifically, we utilized LBCS as a counterparty to hedge a portion of our natural gas and oil production. The obligations of LBCS are guaranteed by Lehman, and the Lehman bankruptcy filing resulted in an event of default under our ISDA agreement with LBCS allowing us to terminate the ISDA on September 18, 2008, and cancel the outstanding transactions. The potential loss associated with the termination of such transactions is not material to us.

Chesapeake sells natural gas to Eagle Energy Partners 1, LP (Eagle Energy), previously an affiliate of Lehman. Eagle Energy was not included in the Lehman bankruptcy filing. On September 26, 2008, Eagle Energy notified us that EDF Trading Limited (EDFT), a wholly-owned subsidiary of Électricité de France SA (EDF), had entered into an agreement with Lehman to acquire Eagle Energy. The acquisition of Eagle Energy by EDFT was completed on October 31, 2008. We have received cash payment for all natural gas that has been sold to Eagle Energy and are continuing to do business with it.

Chesapeake will continue to closely monitor the Lehman bankruptcy situation and will assert its rights under the various contractual relationships. We monitor the credit worthiness of all our counterparties and do not believe a failure by a counterparty would have a material negative impact on our liquidity.

Other financial instruments which potentially subject us to concentrations of credit risk consist principally of investments in equity instruments and accounts receivable. Our accounts receivable are primarily from purchasers of natural gas and oil 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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Contingencies and Commitments

Litigation

We are involved in various disputes incidental to our business operations, including claims from royalty owners regarding volume measurements, post-production costs and prices for royalty calculations. In *Tawney, et al. v. Columbia Natural Resources, Inc.*, Chesapeake s wholly-owned subsidiary Chesapeake Appalachia, L.L.C., formerly known as Columbia Natural Resources, LLC (CNR), is a defendant in a class action lawsuit filed in 2003 in the Circuit Court for Roane County, West Virginia by royalty owners. The plaintiffs allege that CNR underpaid royalties by improperly deducting post-production costs, failing to pay royalty on total volumes of natural gas produced and not paying a fair value for the natural gas produced from their leases. The plaintiff class consists of West Virginia royalty owners receiving royalties after July 31, 1990 from CNR. Chesapeake acquired CNR in November 2005, and its seller acquired CNR in 2003 from NiSource Inc. NiSource, a co-defendant in the case, has managed the litigation and indemnified Chesapeake against underpayment claims based on the use of fixed prices for natural gas production sold under certain forward sale contracts and other claims with respect to CNR s operations prior to September 2003.

On January 27, 2007, the Circuit Court jury returned a verdict against the defendants of $404 million, consisting of $134 million in compensatory damages and $270 million in punitive damages. The jury found fraudulent conduct by the defendants with respect to the sales prices used to calculate royalty payments and with respect to the failure of CNR to disclose post-production deductions. On June 28, 2007, the Circuit Court sustained the jury verdict for punitive damages, and on September 27, 2007, it denied all post-trial motions. The defendants stayed the judgment during the pendency of their appeal to the West Virginia Supreme Court of Appeals by filing an irrevocable letter of credit in the amount of $50 million. They filed their initial Petition for Appeal on January 24, 2008. On May 22, 2008, the West Virginia Supreme Court of Appeals refused to hear the appeal. NiSource and Chesapeake filed two petitions for writ of certiorari to the United States Supreme Court on August 20, 2008, asserting among other things that their constitutional rights were violated by the manner in which punitive damages were awarded, the amount of punitive damages, and the lack of meaningful state court appellate review of the punitive damages award. The U.S. Supreme Court may or may not decide to accept the appeal. The West Virginia Supreme Court of Appeals has granted a stay of the judgment until the proceedings before the U.S. Supreme Court are concluded.

On October 22, 2008, the parties in the *Tawney* matter entered into a settlement agreement providing for the establishment of a settlement fund of $380 million, and the Circuit Court for Roane County, West Virginia granted preliminary approval of the settlement on October 23, 2008. The settlement is subject to final approval by the Circuit Court, following a fairness hearing currently scheduled for November 22, 2008. Chesapeake s share of the prospective settlement fund would be approximately $41 million, which amount has previously been fully reserved. If the settlement receives final approval, NiSource and Chesapeake intend to withdraw their U.S. Supreme Court certiorari petitions. Chesapeake believes this litigation will not have a material adverse effect on its results of operations, financial condition or liquidity.

Chesapeake is subject to other legal proceedings and claims which arise in the ordinary course of business. In our opinion, the final resolution of these proceedings and claims will not have a material effect on the company.

Employment Agreements with Officers

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing January 1, 2008. The term of the agreement is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer s base compensation (defined as base salary plus bonus compensation received during the preceding 12 months) and benefits would continue during the remaining term of the agreement. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation upon the happening of certain events following a change of control. The agreement further provides that any stock-based awards held by the chief executive officer and deferred compensation will immediately become 100% vested upon termination of employment without cause, incapacity, death or retirement at or after

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

age 55, and any unexercised stock options will not terminate as the result of termination of employment. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009. These agreements provide for the continuation of salary for one year in the event of termination of employment without cause or death and, in the event of a change of control, a payment in the amount of two times the executive officer s base compensation. These executive officers are entitled to continue to receive compensation and benefits for 180 days following termination of employment as a result of incapacity. Any stock-based awards held by such executive officers will immediately become 100% vested upon termination of employment without cause, a change of control, death, or retirement at or after age 55.

Environmental Risk

Due to the nature of the natural gas and oil 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 September 30, 2008.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 81 drilling rigs and related equipment for $660 million and entered into a master lease agreement under which we agreed to lease the rigs from the buyer for initial terms of seven to ten years for lease payments of approximately $90 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to service operations expense over the lease term. Under the rig leases, we can exercise an early purchase option after six or seven years or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic lease equal to the fair market rental value of the rigs as determined at the time of renewal. As of September 30, 2008, Chesapeake s drilling subsidiaries had contracted to acquire 24 rigs to be constructed during 2008 and 2009. The total remaining cost of the rigs is estimated to be approximately $295 million. Our intent is to sell and lease back those rigs as they are delivered. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2008, the minimum aggregate future rig lease payments were approximately $619 million.

Compressor Leases

In 2007 and 2008, our compression subsidiary sold a significant portion of its existing compressor fleet, consisting of 1,443 compressors, for $303 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from seven to ten years for aggregate lease payments of approximately $36 million annually. The lease obligations are guaranteed by Chesapeake and its other material restricted subsidiaries. These transactions were recorded as sales and operating leasebacks and any related gain or loss will be amortized to natural gas and oil marketing expenses over the lease term. Under the leases, we can exercise an early purchase option after six to nine years or we can purchase the compressors at expiration of the lease for the fair market value at the time. In addition, we have the option to renew the lease for negotiated new terms at the expiration of the lease. Approximately 650 new compressors are on order for approximately $300 million and our intent is to sell and lease back those compressors as they are delivered. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2008, the minimum aggregate future compressor lease payments were approximately $317 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from one to 93 years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. Under the terms of these contracts, we are obligated to pay demand charges as set forth in the transporter s Federal Energy Regulatory Commission (FERC) gas tariff. In exchange, the company receives rights to flow natural gas production through pipelines located in highly competitive markets. As of September 30, 2008, the aggregate amount of such required demand payments was approximately $1.6 billion (excluding demand charges for pipeline projects that are currently seeking regulatory approval).

Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 40 rigs with terms of one to three years. As of September 30, 2008, the aggregate drilling rig commitment was approximately $206 million.

Gas Purchase Obligations

Our marketing segment regularly commits to purchase natural gas from other owners in our properties and such commitments typically are short term in nature. We have also committed to purchase natural gas associated with volumetric production payment transactions. The purchase commitments extend over 11 to 15 year terms based on market prices at the time of production, and the purchased natural gas will be resold. As of September 30, 2008, we were obligated to purchase 371 bcfe under the terms of the volumetric production payments.

Other Commitments

We own a 49% interest in Mountain Drilling Company, a company that specializes in hydraulic drilling rigs which are designed for drilling in urban areas. Chesapeake has an agreement to lend Mountain Drilling Company up to $32 million through December 31, 2009. At September 30, 2008, Mountain Drilling owed Chesapeake $19 million under this agreement.

We invested in Ventura Refining and Transmission LLC in early 2007 and today own a 25% interest. There were no refineries in western Oklahoma until Ventura opened its refinery in 2006. We have an agreement to lend Ventura Refining and Transmission LLC up to $28 million through January 31, 2017. At September 30, 2008, there was $27 million outstanding under this agreement. Additionally, we have agreed to guarantee up to $70 million in commitments for Ventura to support its operating activities. As of September 30, 2008, we had guaranteed $62 million.

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(Unaudited)

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 Current Quarter and the Current Period, diluted shares do not include the common stock equivalent of our 4.5% preferred stock outstanding prior to conversion (convertible into 526,477 and 1,517,305 shares, respectively) and the preferred stock adjustment to net income does not include $12 million and $14 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the Current Quarter and the Current Period, diluted shares do not include the common stock equivalent of our 5.0% (Series 2005B) preferred stock outstanding prior to conversion (convertible into 1,019,947 and 5,229,841 shares, respectively) and the preferred stock adjustment to net income does not include $13 million and $62 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

Reconciliations for the three and nine months ended September 30, 2008 and 2007 are as follows:

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions except per share data)		
For the Three Months Ended September 30, 2008:			
Basic EPS:			
Income available to common shareholders	$ 3,282	554	$ 5.93
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 4.50% convertible preferred stock		6	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		5	
Common shares assumed issued for 6.25% convertible preferred stock		1	
Effect of contingent convertible senior notes outstanding during the period	9	13	
Employee stock options		2	
Restricted stock		7	
Preferred stock dividends	6		
Diluted EPS Income available to common shareholders and assumed conversions	$ 3,297	588	$ 5.61

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(Unaudited)

	Income (Numerator)	Shares (Denominator)	Per Share Amount
	(in millions except per share data)		
For the Three Months Ended September 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 346	454	$ 0.76
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 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		15	
Common shares assumed issued for 6.25% convertible preferred stock		17	
Employee stock options		3	
Restricted stock		2	
Preferred stock dividends	26		
Diluted EPS Income available to common shareholders and assumed conversions	$ 372	517	$ 0.72
For the Nine Months Ended September 30, 2008:			
Basic EPS:			
Income available to common shareholders	$ 1,490	523	$ 2.85
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 4.50% convertible preferred stock		6	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		5	
Common shares assumed issued for 6.25% convertible preferred stock		1	
Effect of contingent convertible senior notes outstanding during the period	12	13	
Employee stock options		2	
Restricted stock		7	
Preferred stock dividends	18		
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,520	557	$ 2.73
For the Nine Months Ended September 30, 2007:			
Basic EPS:			
Income available to common shareholders	$ 1,071	452	$ 2.37
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 4.50% convertible preferred stock		8	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		18	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		15	
Common shares assumed issued for 6.25% convertible preferred stock		17	

Employee stock options		4	
Restricted stock		2	
Preferred stock dividends	77		
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,148	516	$ 2.23

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5. Stockholders Equity, Restricted Stock and Stock Options

Common Shares

The following is a summary of the changes in our common shares outstanding for the nine months ended September 30, 2008 and 2007:

	2008	2007
	(in thousands)	
Shares outstanding at January 1	511,648	458,601
Common stock issuances	51,750	
Preferred stock conversions	12,673	
Stock option exercises	1,473	1,254
Restricted stock issuances net of terminations	4,352	14,367
Shares outstanding at September 30	581,896	474,222

In the Prior Period, we issued 9.8 million shares of restricted stock to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in August 2009 with the remaining 50% vesting in August 2011.

Preferred Shares

The following is a summary of the changes in our preferred shares outstanding for the nine months ended September 30, 2008 and 2007:

	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)		
Shares outstanding at January 1, 2008	3	5	3,450	5,750	144
Conversion/exchange of preferred for common stock			(891)	(3,654)	
Shares outstanding at September 30, 2008	3	5	2,559	2,096	144
Shares outstanding at January 1, 2007 and September 30, 2007	3	4,600	3,450	5,750	2,300

In connection with the exchanges and conversions noted above, we recorded losses of $25 million and $67 million in the Current Quarter and the Current 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 common stock issuable pursuant to the original conversion terms of the preferred stock.

During the Current Period, a holder of our 4.50% cumulative convertible preferred stock exchanged 891,100 shares for 2,227,750 shares of our common stock in a privately negotiated transaction.

During the Current Period, 3,654,385 shares of our 5.0% (series 2005B) cumulative convertible preferred stock were exchanged for 10,443,642 shares of common stock in privately negotiated exchange transactions.

During the Current Period, holders of our 4.125% cumulative convertible preferred stock converted 29 shares into 1,743 shares of common stock, and during the Prior Period, a holder of our 4.125% cumulative convertible preferred stock converted 3 shares into 180 shares of common stock.

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Stock-Based Compensation

Chesapeake s stock-based compensation programs consist of restricted stock and stock options issued to employees and non-employee directors. To the extent compensation cost relates to employees directly involved in natural gas and oil exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized are recognized as general and administrative expenses, production expenses, natural gas and oil marketing expenses or service operations expense. We recorded the following stock-based compensation during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	($ in millions)			
Natural gas and oil properties	$ 30	$ 23	$ 81	$ 45
General and administrative expenses	26	19	66	41
Production expenses	8	7	22	12
Natural gas and oil marketing expenses	3	2	8	3
Service operations expense	2	1	4	2
Total	$ 69	$ 52	$ 181	$ 103

Restricted Stock. Chesapeake regularly issues shares of restricted common stock to employees and to non-employee directors. 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 generally four or five years from the date of grant for employees and three years for non-employee directors.

A summary of the changes in unvested shares of restricted stock during the Current Period is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2008	19,688,759	$ 32.42
Granted	6,223,714	$ 53.24
Vested	(3,818,427)	$ 28.02
Forfeited	(744,276)	$ 36.95
Unvested shares as of September 30, 2008	21,349,770	$ 39.12

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $209 million based on the stock price at the time of vesting.

As of September 30, 2008, there was $713 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.

The vesting of certain restricted stock grants results in state and federal income tax benefits related to the difference between the market price of the common stock at the date of vesting and the date of grant. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to restricted stock of $18 million, $3 million, $27 million and $4 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

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Stock Options. Prior to 2006, we granted stock options under several stock compensation plans. Outstanding options expire ten years from the date of grant and vest 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 millions)
Outstanding at January 1, 2008	4,445,455	$ 7.55	4.37	$ 141
Exercised	(1,522,413)	$ 6.60		$ 64
Forfeited	(1,000)	$ 15.48		
Expired	(133)	$ 9.57		
Outstanding at September 30, 2008	2,921,909	$ 8.04	3.78	$ 81
Exercisable at September 30, 2008	2,918,784	$ 8.03	3.78	$ 81

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

As of September 30, 2008, unrecognized compensation cost related to unvested stock options was nominal.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $3 million, $2 million, $15 million and $9 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

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6. Senior Notes and Revolving Bank Credit Facility

Our total debt consisted of the following as of September 30, 2008 and December 31, 2007:

	September 30, 2008	December 31, 2007
	($ in millions)	
7.5% Senior Notes due 2013	$ 364	$ 364
7.625% Senior Notes due 2013	500	500
7.0% Senior Notes due 2014	300	300
7.5% Senior Notes due 2014	300	300
6.375% Senior Notes due 2015	600	600
7.75% Senior Notes due 2015(a)		300
6.625% Senior Notes due 2016	600	600
6.875% Senior Notes due 2016	670	670
6.25% Euro-denominated Senior Notes due 2017(b)	845	876
6.5% Senior Notes due 2017	1,100	1,100
6.25% Senior Notes due 2018	600	600
7.25% Senior Notes due 2018	800	
6.875% Senior Notes due 2020	500	500
2.75% Contingent Convertible Senior Notes due 2035(c)	690	690
2.5% Contingent Convertible Senior Notes due 2037(c)	1,650	1,650
2.25% Contingent Convertible Senior Notes due 2038(c)	1,380	
Revolving bank credit facility	3,474	1,950
Discount on senior notes	(90)	(105)
Interest rate derivatives(d)	62	55
Total notes payable and long-term debt	$ 14,345	$ 10,950

(a) The 7.75% Senior Notes due 2015 were redeemed on July 7, 2008 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

(b) The principal amount shown is based on the dollar/euro exchange rate of $1.4081 to 1.00 and $1.4603 to 1.00 as of September 30, 2008 and December 31, 2007, respectively. See Note 2 for information on our related cross currency swap.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. 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. One such triggering circumstance is that the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the third quarter of 2008, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the fourth quarter of 2008 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent 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. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.83	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.47	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(d) See Note 2 for discussion related to these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 contingent convertible senior notes, 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; enter into sale/leaseback transactions; 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 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. As of September 30, 2008, our obligations under our outstanding senior notes were fully and unconditionally guaranteed, jointly and severally, by all of our wholly-owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis. In October 2008, we restructured our non-Appalachian midstream operations, as described in Note 11. As a result, certain of our wholly-owned subsidiaries having significant assets and operations do not presently guarantee our outstanding senior notes.

We have a $3.5 billion syndicated revolving bank credit facility which matures in November 2012. As of September 30, 2008, we had $3.474 billion in outstanding borrowings under our facility and utilized approximately $14 million of the facility for various letters of credit. To ensure that our revolving bank credit facility could be fully utilized in these turbulent economic times, we borrowed the remaining capacity under our facility at the end of the Current Quarter and invested the cash proceeds in short-term U.S. Treasury and other highly liquid securities. As a result, on September 30, 2008, we had cash and cash equivalents on hand of approximately $1.964 billion. All 36 lenders that participate in our revolving bank credit facility fully funded their commitment, with the exception of LBCB, a subsidiary of Lehman, which did not fund its $11 million share of the advance. See *Concentration of Credit Risk* in Note 2.

Borrowings under our facility are secured by certain producing natural gas and oil properties and bear interest at our option 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), plus a margin that varies from 0.75% to 1.50% per annum 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 0.20% 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 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.47 to 1 and our indebtedness to EBITDA ratio was 2.48 to 1 at September 30, 2008. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration , if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

Two of our subsidiaries, Chesapeake Exploration, L.L.C. 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 restricted subsidiaries.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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. Our exploration and production operational segment and natural gas and oil marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and oil. As of September 30, 2008, the marketing segment was responsible for gathering, processing, compressing, transporting and selling natural gas and oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations which 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 (loss) before income taxes. Revenues from the marketing segment s sale of natural gas and oil related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $1.591 billion, $843 million, $4.667 billion and $2.441 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. The following table presents selected financial information for Chesapeake s operating segments. Our drilling rig and trucking service operations are presented in Other Operations .

	Exploration and Production	Marketing	Other Operations ($ in millions)	Intercompany Eliminations	Consolidated Total
For the Three Months Ended September 30, 2008:					
Revenues	$ 6,408	$ 2,629	$ 164	$ (1,710)	$ 7,491
Intersegment revenues		(1,591)	(119)	1,710	
Total revenues	$ 6,408	$ 1,038	$ 45	$	$ 7,491
Income (loss) before income taxes	$ 5,370	$ 19	$ 21	$ (23)	$ 5,387
For the Three Months Ended September 30, 2007:					
Revenues	$ 1,492	$ 1,344	$ 133	$ (942)	$ 2,027
Intersegment revenues		(843)	(99)	942	
Total revenues	$ 1,492	$ 501	$ 34	$	$ 2,027
Income before income taxes	$ 586	$ 11	$ 38	$ (35)	$ 600
For the Nine Months Ended September 30, 2008:					
Revenues	$ 5,587	$ 7,601	$ 467	$ (5,007)	$ 8,648
Intersegment revenues		(4,667)	(340)	5,007	
Total revenues	$ 5,587	$ 2,934	$ 127	$	$ 8,648
Income (loss) before income taxes	$ 2,528	$ 49	$ 67	$ (69)	$ 2,575
For the Nine Months Ended September 30, 2007:					
Revenues	$ 4,164	$ 3,887	$ 357	$ (2,697)	$ 5,711
Intersegment revenues		(2,441)	(256)	2,697	

Total revenues	$	4,164	$	1,446	$	101	$		$	5,711
Income before income taxes	$	1,813	$	29	$	104	$	(94)	$	1,852
As of September 30, 2008:										
Total assets	$	37,423	$	2,926	$	644	$	(975)	$	40,018
As of December 31, 2007:										
Total assets	$	29,317	$	1,759	$	487	$	(829)	$	30,734

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Natural Gas and Oil Properties

Joint Ventures

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company to develop our Haynesville Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, Plains acquired a 20% interest in our approximately 550,000 net acres of Haynesville Shale leasehold for $1.65 billion in cash, subject to normal post-closing adjustments. Plains has also agreed to fund 50% of our 80% share of the costs associated with drilling and completing future Haynesville Shale joint venture wells over a multi-year period, up to an additional $1.65 billion. In addition, Plains has the right to a 20% participation in any additional leasehold we acquire in the Haynesville Shale. Cash proceeds from the sale were reflected as a reduction of natural gas and oil properties for accounting purposes, with no gain or loss recognized. PXP s commitment to fund 50% of our share of future drilling and completion costs (up to $1.65 billion) is expected to reduce DD&A expense by reducing the amount of capital we would invest to develop our Haynesville properties.

On September 5, 2008, we entered into a joint venture with BP America Inc. to develop our Fayetteville Shale leasehold in Arkansas. Under the terms of the joint venture, BP acquired a 25% interest in our approximately 540,000 net acres of Fayetteville Shale leasehold for $1.1 billion in cash, which was paid at closing. BP has also agreed to pay $800 million by funding 100% of Chesapeake s 75% share of drilling and completion expenditures until the $800 million obligation has been funded. In addition, BP has the right to a 25% participation in any additional leasehold we acquire in the Fayetteville Shale. Cash proceeds from the sale were reflected as a reduction of natural gas and oil properties for accounting purposes, with no gain or loss recognized. BP s commitment to fund our share of future drilling and completion costs (up to $800 million) is expected to reduce DD&A expense by reducing the amount of capital we would invest to develop our Fayetteville properties.

Volumetric Production Payments

On May 1, 2008, we sold certain long-lived producing assets in Texas, Oklahoma and Kansas in a volumetric production payment transaction for net proceeds of $616 million. These assets had estimated proved reserves of approximately 94 bcfe and current net production (at the time of sale) of approximately 47 mmcfe per day. Chesapeake retained drilling rights on the properties below currently producing intervals.

On August 1, 2008, we completed another volumetric production payment transaction with estimated proved reserves of approximately 93 bcfe and current net production (at the time of sale) of approximately 46 mmcfe per day from wells in the Anadarko Basin of Oklahoma. This transaction resulted in net proceeds to us of $594 million. For accounting purposes, these transactions were treated as sales of natural gas and oil properties with no gain or loss recognized and our proved reserves were reduced accordingly.

Divestitures

On August 8, 2008, BP America Inc. acquired all of our interests in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play for $1.7 billion in cash. The properties were producing approximately 50 mmcfe per day (at the time of sale).

Also in the Current Period, we sold non-core natural gas and oil assets in the Rocky Mountains and in the Mid-Continent for proceeds of $243 million.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Fair Value Measurements

Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of September 30, 2008.

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 1,964	$	$	$ 1,964
Derivatives, net	$	$ 406	$ (480)	$ (74)
Investments	$ 44	$	$	$ 44
Other long-term assets	$ 23	$	$	$ 23
Long-term debt	$	$	$ (2,275)	$ (2,275)
Other long-term liabilities	$ (23)	$	$	$ (23)

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

Investments. The fair value of Chesapeake s investment in Gastar Exploration Ltd. common stock is based on a quoted market price.

Other Long-Term Assets and Liabilities. The fair value of other long-term assets and liabilities, consisting of our Deferred Compensation Plan, is based on quoted market prices.

Level 2 Fair Value Measurements

Derivatives. The fair values of our natural gas swaps are measured internally using established index prices and other sources. These values are based upon, among other things, futures prices and time to maturity.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Level 3 Fair Value Measurements

Derivatives. The fair values of our derivatives, excluding natural gas swaps, are based on estimates provided by our respective counterparties and reviewed internally using established index prices and other sources. These values are based upon, among other things, futures prices, interest rate curves and time to maturity.

Debt. The fair value of our long-term debt is based on face value of the debt along with the value of the related interest rate swaps. The interest rate swap values are based on estimates provided by our respective counterparties and reviewed internally for reasonableness using future interest rate curves and time to maturity.

A reconciliation of Chesapeake s assets and liabilities classified as Level 3 measurements is presented below.

	Derivatives	Debt ($ in millions)	Total
Balance of Level 3 as of January 1, 2008	$ (340)	$ (2,404)	$ (2,744)
Total gains or losses (realized/unrealized):			
Included in earnings[(a)]	409	29	438
Included in other comprehensive income (loss)	(82)		(82)
Purchases, issuances and settlements	(467)	100[(b)]	(367)
Transfers in and out of Level 3			
Balance of Level 3 as of September 30, 2008	$ (480)	$ (2,275)	$ (2,755)

(a)	Natural Gas and Oil Revenue	Interest
	($ in millions)	
Total gains and losses related to derivatives included in earnings for the period	$ 430	$ (21)
Change in unrealized gains or losses relating to assets still held at reporting date	$ 138	$ (22)

(b) Amount represents debt now recorded at fair value as a result of new interest rate swaps entered into in the Current Period.

10. Recently Issued and Proposed Accounting Standards

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

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Since we have not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

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(Unaudited)

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact that adoption of this statement will have on our financial disclosures.

In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)*. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, *Accounting for Convertible Debt and Debt Issued with Stock Purchase Warrants*. The accounting prescribed by FSP APB 14-1 would increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers will have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. We are currently assessing the impact that adoption of this staff position will have on our consolidated financial position, results of operations or cash flows.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) No. 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. FSP EITF 03-6-1 addresses whether instruments granted in share-based payments transactions are participating securities prior to vesting and therefore need to be included in the earnings allocation in calculating earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. FSP EITF No. 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per share. FSP EITF No. 03-6-1 is effective for fiscal years beginning after December 15, 2008; earlier application is not permitted. We are currently evaluating the impact, if any, the adoption of FSP EITF No. 03-6-1 will have on our financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*. FSP FAS 157-3 clarifies the application of FASB statement No. 157, *Fair Value Measurements*, in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP is effective upon issuance and will not have a material impact on our financial position, results of operations or cash flows.

11. Subsequent Events

In early October 2008, Chesapeake designated its midstream wholly-owned subsidiaries as unrestricted subsidiaries under each of Chesapeake s indentures and its $3.5 billion revolving bank credit agreement. On October 16, 2008, one of these unrestricted subsidiaries, Chesapeake Midstream Operating, L.L.C., entered into a $460 million syndicated revolving bank credit facility which matures in October 2013. Borrowings under the midstream revolving credit facility will be used to fund capital expenditures and working capital associated with our midstream operations.

Subsequent to September 30, 2008, holders of certain of our contingent convertible senior notes exchanged their senior notes for shares of common stock in privately negotiated exchanges as summarized below (in millions):

Contingent

Convertible Senior Notes	Principal Amount	Number of Common Shares
2.75% due 2035	$ 160	5.8
2.50% due 2037	$ 262	8.1
2.25% due 2038	$ 219	5.5

The difference between the face value of the notes that were exchanged and the fair value of the common stock issued will be treated as a gain on the cancellation of indebtedness.

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ITEM 2. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***
Overview

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the three and nine months ended September 30, 2008 (the Current Quarter and the Current Period) and the three and nine months ended September 30, 2007 (the Prior Quarter and the Prior Period):

	Three Months Ended September 30, 2008	Three Months Ended September 30, 2007	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
Net Production:				
Natural gas (mmcf)	196,657	170,325	579,423	467,197
Oil (mbbls)	2,810	2,680	8,372	7,147
Natural gas equivalent (mmcfe)	213,517	186,405	629,655	510,079
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 1,717	$ 971	$ 5,046	$ 2,918
Natural gas derivatives realized gains (losses)	(140)	290	(174)	890
Natural gas derivatives unrealized gains (losses)	3,854	73	325	(58)
Total natural gas sales	5,431	1,334	5,197	3,750
Oil sales	319	190	915	443
Oil derivatives realized gains (losses)	(106)	(4)	(280)	26
Oil derivatives unrealized gains (losses)	764	(28)	(245)	(55)
Total oil sales	977	158	390	414
Total natural gas and oil sales	$ 6,408	$ 1,492	$ 5,587	$ 4,164
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 8.73	$ 5.71	$ 8.71	$ 6.25
Oil ($ per bbl)	$ 113.53	$ 70.76	$ 109.28	$ 61.91
Natural gas equivalent ($ per mcfe)	$ 9.54	$ 6.23	$ 9.47	$ 6.59
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 8.02	$ 7.41	$ 8.41	$ 8.15
Oil ($ per bbl)	$ 75.74	$ 69.25	$ 75.82	$ 65.55
Natural gas equivalent ($ per mcfe)	$ 8.38	$ 7.76	$ 8.75	$ 8.39
Other Operating Income[(a)] ($ in millions):				
Natural gas and oil marketing	$ 24	$ 18	$ 70	$ 52
Service operations	$ 8	$ 11	$ 23	$ 34
Other Operating Income ($per mcfe):				
Natural gas and oil marketing	$ 0.11	$ 0.10	$ 0.11	$ 0.10
Service operations	$ 0.04	$ 0.06	$ 0.04	$ 0.07
Expenses ($ per mcfe):				
Production expenses	$ 1.12	$ 0.89	$ 1.04	$ 0.90
Production taxes	$ 0.41	$ 0.30	$ 0.40	$ 0.30
General and administrative expenses	$ 0.50	$ 0.33	$ 0.46	$ 0.33
Natural gas and oil depreciation, depletion and amortization	$ 2.25	$ 2.57	$ 2.41	$ 2.58
Depreciation and amortization of other assets	$ 0.23	$ 0.24	$ 0.20	$ 0.24
Interest expense[(b)]	$ 0.26	$ 0.52	$ 0.35	$ 0.52
Interest Expense ($ in millions):				
Interest expense	$ 51	$ 98	$ 220	$ 266
Interest rate derivatives realized (gains) losses	5	(1)	1	
Interest rate derivatives unrealized (gains) losses	(8)	19	(9)	13

Total interest expense	$ 48	$ 116	$ 212	$ 279
Net Wells Drilled	455	529	1,388	1,480
Net Producing Wells as of the End of the Period	22,475	20,932	22,475	20,932

(a) Includes revenue and operating costs.

(b) Includes the effects of realized gains (losses) from interest rate derivatives, but excludes the effects of unrealized gains (losses) and is net of amounts capitalized.

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We are the largest producer of natural gas in the United States. We own interests in approximately 40,500 producing natural gas and oil wells that are currently producing approximately 2.3 bcfe per day, 92% of which is natural gas. Our strategy is focused on discovering, acquiring and developing conventional and unconventional natural gas reserves onshore in the U.S..

Our most important operating area has historically been the *Mid-Continent* region of Oklahoma, Arkansas, southwestern Kansas and the Texas Panhandle. At September 30, 2008, 46% of our estimated proved natural gas and oil reserves were located in the Mid-Continent region. However, during the past five years, we have established a top-two position in the four major unconventional plays onshore in the U.S., including the Barnett Shale in the *Fort Worth Basin* in north-central Texas; the Haynesville Shale in the *Ark-La-Tex* area of East Texas and northern Louisiana; the Fayetteville Shale in the *Arkoma Basin* of Arkansas; and the Marcellus and Lower Huron Shales in the *Appalachian Basin* of Kentucky, West Virginia, Pennsylvania and New York. In addition, we are pursuing other unconventional plays in the *Anadarko Basin* of western Oklahoma, the *Ardmore Basin* of southern Oklahoma, the *Arkoma Basin* of eastern Oklahoma and the *Permian and Delaware Basins* of West Texas and eastern New Mexico.

During the Current Period, Chesapeake continued the industry s most active drilling program and drilled 1,435 gross (1,193 net) operated wells and participated in another 1,439 gross (195 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 97% for non-operated wells. Also during the Current Period, we invested $3.852 billion in operated wells (using an average of 148 operated rigs) and $576 million in non-operated wells (using an average of 118 non-operated rigs) for total drilling, completing and equipping costs of $4.428 billion.

Chesapeake began 2008 with estimated proved reserves of 10.879 tcfe and ended the Current Period with 12.075 tcfe, an increase of 1.196 tcfe, or 11%. During the Current Period, we replaced 630 bcfe of production with an internally estimated 1.826 tcfe of new proved reserves, for a reserve replacement rate of 290%. Reserve replacement through the drillbit was 2.286 tcfe, or 363% of production, including 1.128 tcfe of positive performance revisions and 13 bcfe of positive revisions resulting from natural gas and oil price increases between December 31, 2007 and September 30, 2008. Reserve replacement through the acquisition of proved reserves was 165 bcfe. During the Current Period, we divested 638 bcfe of estimated proved reserves. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2008 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.

Since 2000, Chesapeake has invested $13.3 billion in new leasehold (net of divestitures) and 3-D seismic acquisitions and now owns the largest combined inventories of onshore leasehold (15.6 million net acres) and 3-D seismic (21.1 million acres) in the U.S. On this leasehold, the company has approximately 37,000 net drillsites representing more than a 10-year inventory of drilling projects.

Our net debt as a percentage of total capitalization (total capitalization is the sum of net debt and stockholders equity) was 43% as of September 30, 2008 and 47% as of December 31, 2007. The average maturity of our long-term debt is over eight years with an average interest rate of approximately 5.4%. No scheduled principal payments are required under our senior notes until 2013 when $864 million is due.

Business Strategy

In response to a decrease in natural gas prices since June 30, 2008, the current global economic outlook and concerns about a potential over supply of natural gas in the U.S. market, we have reduced our planned capital expenditures during the second half of 2008 through year-end 2010. Our current budgeted capital expenditures for drilling, leasehold and producing property acquisitions, geophysical costs, and additions to midstream, compression and other property and equipment are $2.4 billion to $2.8 billion in the fourth quarter of 2008 and $7.0 billion to $8.3 billion in 2009. We will continue to evaluate market conditions and natural gas prices and further reduce our capital expenditures if necessary.

We anticipate that our remaining 2008 and 2009 budgeted exploration and development capital expenditures, together with other capital expenditure requirements, will exceed our cash flow from operations and our borrowing capacity under our revolving credit facilities. To create additional value from our proved and unproved properties, to provide for our anticipated cash requirements and to generate excess cash to increase our financial flexibility, we expect to continue to engage in asset monetization transactions, including sales of producing properties, undeveloped acreage and non-strategic assets, additional joint venture arrangements and the sale of volumetric production payments, and we may consider alternative sources of public or private investment in the company or its subsidiaries. Our current budgeted cash inflows for these types of transactions are $2.5 billion to $3.0 billion in the fourth quarter of 2008 and $2.3 billion to $3.3 billion in 2009. While we believe that some or all of these sources of liquidity will be available to us, as they have been in 2008 to date, we will further curtail our capital spending if we are unable to access sufficient cash to fund our presently planned levels of capital spending and operations.

Since March 31, 2008, as detailed below, we have completed significant transactions that have provided approximately $10.4 billion of new capital. In each case, we used the proceeds to temporarily repay outstanding indebtedness under our revolving bank credit facility, which we have reborrowed to fund capital expenditures, and for other general corporate purposes, including the redemption of our 7.75% Senior Notes due 2015 ($300 million principal amount). In addition, up to $2.45 billion of our future drilling and completion costs in the Haynesville Shale and Fayetteville Shale will be funded by our joint venture partners.

On April 2, 2008, we issued 23 million shares of our common stock in a public offering at a price of $45.75 per share, and on July 15, 2008, we issued 28.75 million shares of our common stock in a public offering at a price of $57.25 per share. On May 20, 2008, we completed public offerings of $800 million of our 7.25% Senior Notes due 2018 and $1.380 billion of our 2.25% Contingent Convertible Senior Notes due 2038. We received aggregate net proceeds of approximately $4.734 billion from these four offerings. The availability of any additional capital from the public or private markets is uncertain at this time.

On May 1, 2008, we completed a volumetric production payment (VPP) transaction involving approximately 94 bcfe of estimated proved reserves and current net production (at the time of sale) of approximately 47 mmcfe per day from wells in Texas, Oklahoma and Kansas. This transaction resulted in net proceeds to us of $616 million. On August 1, 2008, we completed another VPP transaction with estimated proved reserves of approximately 93 bcfe and current net production (at the time of sale) of approximately 46 mmcfe per day from wells in the Anadarko Basin in Oklahoma. This transaction resulted in net proceeds to us of $594 million. This was our third VPP transaction and we expect to raise additional capital by this means in the fourth quarter of 2008 and in 2009.

On July 1, 2008, we entered into a joint venture with Plains Exploration & Production Company to develop our Haynesville Shale leasehold in Northwest Louisiana and East Texas. Under the terms of the joint venture, Plains acquired a 20% interest in our approximately 550,000 net acres of Haynesville Shale leasehold for $1.65 billion in cash, subject to customary post-closing adjustments. Plains has also agreed to fund 50% of our 80% share of the costs associated with drilling and completing future Haynesville Shale joint venture wells over a multi-year period, up to an additional $1.65 billion. In addition, Plains will have the right to a 20% participation in any additional leasehold we acquire in the Haynesville Shale.

On September 5, 2008, we entered into a joint venture with BP America Inc. to develop our Fayetteville Shale leasehold in Arkansas. Under the terms of the joint venture, BP acquired a 25% interest in our approximately 540,000 net acres of Fayetteville Shale leasehold for $1.1 billion in cash paid at closing. BP will pay an additional $800 million by funding 100% of Chesapeake s 75% share of drilling and completion expenditures until the $800 million obligation has been funded. In addition, BP has the right to a 25% participation in any additional leasehold we acquire in the Fayetteville Shale.

We are presently in joint venture negotiations for our Marcellus Shale play on a promoted basis as well. These joint ventures allow us to generate profits from the sale of a portion of our leasehold in the joint venture areas, recover much or all of our initial leasehold investments in these plays, reduce our ongoing capital costs and minimize future risks.

On August 8, 2008, BP America Inc. acquired all of our interests in approximately 90,000 net acres of leasehold and producing natural gas properties in the Arkoma Basin Woodford Shale play for $1.7 billion in cash. The properties, which are located in Atoka, Coal, Hughes and Pittsburg counties, Oklahoma, were producing approximately 50 mmcfe per day at the time of sale.

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We have resumed plans to sell either a minority interest in our non-Appalachian midstream natural gas business or specific midstream assets. Proceeds from any sale will be used to fund a portion of the costs associated with building the midstream infrastructure in various shale plays, primarily in the Haynesville Shale. On October 16, 2008, we closed a new secured revolving bank credit facility for the midstream operations. The facility matures in October 2013 and has initial availability of $460 million.

Management believes that our planned leasehold and development joint ventures and various asset monetization programs benefit the company in several ways. We will be able to improve our asset base, reduce our financial risk, decrease our DD&A rate and increase our profitability per unit of production, thereby increasing our returns on capital and advancing future value creation.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund operating expenses and capital expenditures. Cash provided by operating activities was $4.305 billion in the Current Period compared to $3.389 billion in the Prior Period. The $916 million increase in the Current Period was primarily due to higher natural gas and oil prices and higher volumes of natural gas and oil production. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as depreciation, depletion and amortization, deferred income taxes and unrealized gains and (losses) on derivatives. See the discussion below under *Results of Operations*.

Changes in market prices for natural gas and oil directly impact the level of our cash flow from operations. While a decline in natural gas or oil prices would affect the amount of cash flow that would be generated from operations, we currently have hedged through swaps and collars 73% of our expected remaining natural gas and oil production in 2008 and 67% of our expected natural gas and oil production in 2009 at average prices of $9.09 and $8.65 per mcfe, respectively. Our natural gas and oil hedges as of September 30, 2008 are detailed in Item 3 of Part I of this report. Depending on changes in natural gas and oil futures markets and management s view of underlying natural gas and oil supply and demand trends, we may increase or decrease our current hedging positions.

As of September 30, 2008, we had a net natural gas and oil derivative asset of $46 million. We satisfy commodity derivative liabilities from a portion of the proceeds of natural gas and oil production sold at market prices during the period of contract settlement (which will occur through 2022). We have arrangements with our hedging counterparties that allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations in the value of our natural gas and oil hedges by making collateral allocations from our bank credit facility or directly pledging natural gas and oil properties, rather than posting cash or letters of credit with the counterparties.

Our $3.5 billion bank credit facility and cash and cash equivalents are other sources of liquidity. At November 6, 2008, there was no borrowing capacity available under the revolving bank credit facility; however, we had approximately $800 million of cash on hand and $378 million of borrowing capacity under the midstream credit facility. We use the facilities and cash on hand to fund daily operating activities and acquisitions as needed. We borrowed $12.831 billion and repaid $11.307 billion in the Current Period, and we borrowed $5.949 billion and repaid $4.177 billion in the Prior Period.

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On April 2, 2008, we issued 23 million shares of our common stock in a public offering at a price of $45.75 per share, and on July 15, 2008, we issued 28.75 million shares of common stock in a public offering at a price of $57.25 per share. On May 20, 2008 we completed public offerings of $800 million of our 7.25% Senior Notes due 2018 and $1.380 billion of our 2.25% Contingent Convertible Senior Notes due 2038. These four offerings resulted in aggregate net proceeds to us of approximately $4.734 billion, which we used to fund the redemption of our 7.75% Senior Notes due 2015 and to temporarily repay indebtedness outstanding under our revolving bank credit facility. The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30,			
	2008		2007	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Common stock	$ 2,698	$ 2,598	$	$
Contingent convertible unsecured senior notes	1,380	1,349	1,650	1,607
Unsecured senior notes guaranteed by subsidiaries	800	787		
Total	$ 4,878	$ 4,734	$ 1,650	$ 1,607

In May 2008, we sold a portion of our proved reserves in certain producing assets in Texas, Oklahoma and Kansas in a VPP transaction for proceeds of approximately $616 million, net of transaction costs. We completed another VPP transaction in August 2008, when we sold a portion of our proved reserves in certain producing assets in the Anadarko Basin of Oklahoma for proceeds of approximately $594 million, net of transaction costs.

Our primary use of funds is for capital expenditures related to exploration, development and acquisition of natural gas and oil properties. We refer you to the table under *Investing Activities* below, which sets forth the components of our natural gas and oil investing activities for the Current Period and the Prior Period. We retain a significant degree of control over the timing of our capital expenditures which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, 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.

We paid dividends on our common stock of $106 million and $85 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.0675 to $0.075 per share beginning with the dividend paid in July 2008. Dividends paid on our preferred stock decreased to $29 million in the Current Period from $78 million in the Prior Period as a result of conversions and exchanges of preferred stock into common stock during the Current Period and 2007. We received $8 million from the exercise of employee and director stock options in both the Current Period and the Prior Period.

In the Current Period and Prior Period, we paid $146 million and $65 million, respectively, to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

SFAS 123(R) 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 and the Prior Period, we reported a tax benefit from stock-based compensation of $42 million and $13 million, respectively.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased $210 million in the Current Period and decreased $54 million in the Prior Period. 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.

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Credit Risk

A significant portion of our liquidity is concentrated in both cash and cash equivalents and derivative instruments. On September 30, 2008, our cash and cash equivalents were invested in money market funds with investment grade ratings. A significant portion of these funds was invested at the close of business on September 19, 2008, and is protected under the U.S. Treasury Department s Temporary Guarantee Program. The remaining funds were spread among several counterparties to mitigate the risk. Derivative instruments enable us to hedge a portion of our exposure to natural gas and oil prices and interest rate volatility. These arrangements expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with investment grade rated counterparties deemed by management to be competent and competitive market makers and spread our instruments among multiple counterparties such that no single counterparty represents a material credit risk to the company. Recently there have been concerns about the ability of certain counterparties to continue to meet their financial obligations. We monitor the credit worthiness of all our counterparties and do not believe a failure by a counterparty would have a material negative impact on our liquidity.

Our accounts receivable are primarily from purchasers of natural gas and oil ($865 million at September 30, 2008) and exploration and production companies which own interests in properties we operate ($320 million at September 30, 2008). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parental guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

Investing Activities

Cash used in investing activities increased to $8.201 billion during the Current Period, compared to $6.488 billion during the Prior Period. We have continued our active drilling program and our acquisitions are focused on leasehold and property acquisitions needed for planned natural gas and oil development. Our investing activities during the Current Period and the Prior Period reflect our increasing focus on converting our resource inventory into production, redeploying our capital by selling natural gas and oil properties with lower rates of return and increasing our investment in properties with higher return potential, and investing in drilling rigs, midstream systems, compressors and other property and equipment to support our natural gas and oil exploration, development and production activities. We have significantly decreased our budget for natural gas and oil investing activities in 2009. The following table shows our cash used in (provided by) investing activities during these periods:

	Nine Months Ended September 30, 2008	Nine Months Ended September 30, 2007
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Exploration and development of natural gas and oil properties	$ 4,407	$ 3,525
Acquisition of leasehold and unproved properties	6,932	1,703
Acquisitions of natural gas and oil companies and proved properties, net of cash acquired	368	446
Geological and geophysical costs	234	245
Interest on leasehold and unproved properties	289	182
Proceeds from sale of volumetric production payment	(1,210)	
Divestitures of proved and unproved properties and leasehold	(4,666)	
Total natural gas and oil investing activities	6,354	6,101
Other Investing Activities:		
Additions to other property and equipment	1,969	1,005
Proceeds from sale of drilling rigs and equipment	(46)	(322)
Proceeds from sale of compressors	(114)	(147)
Additions to (proceeds from) investments	59	(117)
Sale of other assets	(21)	(32)
Total other investing activities	1,847	387

Total cash used in investing activities	$ 8,201	$ 6,488

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Bank Credit and Hedging Facilities

We have a $3.5 billion syndicated revolving bank credit facility that matures in November 2012. As of September 30, 2008, we had $3.474 billion in outstanding borrowings under this facility and had utilized approximately $14 million of the facility for various letters of credit. To ensure that our revolving credit facility could be fully utilized in these turbulent economic times, we borrowed the remaining capacity under our facility at the end of the Current Quarter and invested the cash proceeds in short-term U.S. Treasury and other highly liquid securities. As a result, on September 30, 2008, we had cash and cash equivalents on hand of approximately $1.964 billion. All 36 lenders that participate in our revolving credit facility fully funded their commitment, with the exception of Lehman Brothers Commercial Bank, a subsidiary of Lehman Brothers Holdings Inc., which has filed for bankruptcy protection. Lehman Brothers Commercial Bank did not fund its $11 million share of the advance.

Borrowings under the facility are secured by certain producing natural gas and oil properties and bear interest at our option 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), plus a margin that varies from 0.75% 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 0.20% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals. Our subsidiaries, Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake and all its other wholly-owned restricted subsidiaries are guarantors.

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 0.70 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.75 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.47 to 1 and our indebtedness to EBITDA ratio was 2.48 to 1 at September 30, 2008. 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 of the company and its restricted subsidiaries that we may have with an outstanding principal amount in excess of $75 million.

On October 16, 2008, we closed a new secured revolving bank credit facility for our non-Appalachian midstream operations, which have recently been restructured under a new unrestricted subsidiary, Chesapeake Midstream Partners, L.P. (CMP). Twelve financial institutions are in the facility bank group. The facility matures in October 2013, has initial availability of $460 million and may be expanded up to $750 million at CMP s option, subject to additional bank participation. CMP plans to utilize the facility to fund capital expenditures associated with building additional natural gas gathering and other systems associated with our drilling program and for general corporate purposes related to our midstream operations.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMP and its subsidiaries to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires maintenance of an indebtedness to EBITDA ratio (as defined) not to exceed 3.50 to 1, and an EBITDA (as defined) to interest expense coverage ratio of not less than 2.50 to 1. If CMP or its subsidiaries should fail to perform their obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the midstream facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMP and its subsidiaries may have with an outstanding principal amount in excess of $15 million.

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We have six 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 a stated maximum value. Outstanding transactions under each facility are collateralized by certain of our natural gas and oil properties that do not secure any of our other obligations. The value of reserve collateral pledged to each facility is required to be at least 1.3 or 1.5 times the fair value of transactions outstanding under each facility. In addition, we may pledge collateral from our revolving bank credit facility, from time to time, to these facilities to meet any additional collateral coverage requirements. The hedging facilities are subject to an annual exposure fee, which is assessed quarterly based on the average of the daily negative fair value amounts of the hedges, if any, during the quarter. 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. The fair value of outstanding transactions, per annum exposure fees and the scheduled maturity dates are shown below.

	Secured Hedging Facilities[(a)]					
	#1	#2	#3	#4	#5	#6
	($ in millions)					
Fair value of outstanding transactions, as of September 30, 2008	$ 88	$ (91)	$ (160)	$ (9)	$ 203	$ (195)
Per annum exposure fee	1%	1%	0.8%	0.8%	0.8%	0.8%
Scheduled maturity date	2010	2013	2020	2012	2012	2012

(a) Chesapeake Exploration, L.L.C. is the named party to the facilities numbered 1 3 and Chesapeake Energy Corporation is the named party to the facilities numbered 4 6.

Our revolving bank credit facility, the midstream credit facility and the secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our revolving bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, neither of our credit facilities nor the secured hedging facilities 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.

Senior Note Obligations

In addition to outstanding revolving bank credit facility borrowings discussed above, as of September 30, 2008, senior notes represented approximately $10.9 billion of our total debt and consisted of the following ($ in millions):

7.5% Senior Notes due 2013	$ 364
7.625% Senior Notes due 2013	500
7.0% Senior Notes due 2014	300
7.5% Senior Notes due 2014	300
6.375% Senior Notes due 2015	600
7.75% Senior Notes due 2015[(a)]	
6.625% Senior Notes due 2016	600
6.875% Senior Notes due 2016	670
6.25% Euro-denominated Senior Notes due 2017[(b)]	845
6.5% Senior Notes due 2017	1,100
6.25% Senior Notes due 2018	600
7.25% Senior Notes due 2018	800
6.875% Senior Notes due 2020	500
2.75% Contingent Convertible Senior Notes due 2035[(c)]	690
2.5% Contingent Convertible Senior Notes due 2037[(c)]	1,650
2.25% Contingent Convertible Senior Notes due 2038[(c)]	1,380
Discount on senior notes	(90)
Interest rate derivatives[(d)]	62
Total notes payable and long-term debt	$ 10,871

(a) The 7.75% Senior Notes due 2015 were redeemed on July 7, 2008 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

(b) The principal amount shown is based on the dollar/euro exchange rate of $1.4081 to 1.00 as of September 30, 2008. See Note 2 of our accompanying condensed consolidated financial statements for information on our related cross currency swap.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. 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. One such triggering circumstance is that the price of our common stock exceeds a threshold amount during a specified period in a fiscal quarter. Convertibility based on common stock price is measured quarter by quarter. In the third quarter of 2008, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes during the specified period and, as a result, the holders do not have the option to convert their notes into cash and common stock in the fourth quarter of 2008 under this provision. The notes are also convertible, at the holder s option, during specified five-day periods if the trading price of the notes is below certain levels determined by reference to the trading price of our common stock. In general, upon conversion of a contingent 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. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years, under certain conditions. We may redeem the convertible senior notes once they have been outstanding for ten years at a redemption price of 100% of the principal amount of the notes, payable in cash. The optional repurchase dates, the common stock price conversion threshold amounts and the ending date of the first six-month period contingent interest may be payable for the contingent convertible senior notes are as follows:

Contingent Convertible Senior Notes	Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2015, 2020, 2025, 2030	$ 48.83	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.47	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(d) See Note 2 for discussion related to these instruments.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at September 30, 2008. These include commitments related to drilling rig and compressor leases, transportation and drilling contracts and lending and guarantee agreements. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in Part I of this report.

Union Contract

As a result of the CNR acquisition, we assumed a collective bargaining agreement with the United Steel Workers of America (USWA) which expired effective December 1, 2006, covering approximately 145 of our field employees in West Virginia and Kentucky. We continued to operate under the terms of the collective bargaining agreement while negotiating with the USWA. Contract negotiations began in October 2006 and have been mediated by the Federal Mediation and Conciliation Service. On May 4, 2007, we presented the USWA leadership our last, best and final offer . On December 7, 2007, the USWA membership voted to reject our offer. The company declared an impasse and, effective February 1, 2008, we implemented the terms of our offer with certain minor clarifications. Subsequently, the union filed three separate unfair labor practice charges. One charge was dismissed by the National Labor Relations Board, one charge was settled by mutual agreement, and the final charge is being addressed through the normal grievance process. There have been no strikes, work stoppages or slowdowns since the expiration of the contract, although no assurances can be given that such actions will not occur.

Results of Operations Three Months Ended September 30, 2008 vs. September 30, 2007

General. For the Current Quarter, Chesapeake had a net income of $3.313 billion, or $5.61 per diluted common share, on total revenues of $7.491 billion. This compares to net income of $372 million, or $0.72 per diluted common share, on total revenues of $2.027 billion during the Prior Quarter. The Current Quarter increase is due primarily to an unrealized non-cash mark-to-market gain of $4.618 billion related to future period natural gas and oil hedges resulting primarily from lower natural gas and oil prices as of September 30, 2008 compared to June 30, 2008.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $6.408 billion compared to $1.492 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 213.5 bcfe at a weighted average price of $8.38 per mcfe, compared to 186.4 bcfe produced in the Prior Quarter at a weighted average price of $7.76 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of $4.618 billion and $45 million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $133 million and increased production resulted in a $210 million increase, for a total increase in revenues of $343 million (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Quarter to the Current Quarter was primarily generated from the drillbit.

For the Current Quarter, we realized an average price per mcf of natural gas of $8.02, compared to $7.41 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $75.74 and $69.25 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net decrease in natural gas and oil revenues of $246 million, or $1.15 per mcfe, in the Current Quarter and an increase of $286 million, or $1.53 per mcfe, in the Prior Quarter.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flow. 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 $20 million and $19 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 $3 million without considering the effect of derivative activities.

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

	For the Three Months Ended September 30,			
	2008		2007	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[a][b]	104,046	49%	97,775	52%
Barnett Shale	47,713	22	23,960	13
Permian and Delaware Basins	20,180	10	18,322	10
South Texas and Texas Gulf Coast	16,818	8	19,582	10
Ark-La-Tex	15,243	7	14,492	8
Appalachian Basin[c]	9,517	4	12,274	7
Total production	213,517	100%	186,405	100%

(a) The Current Quarter was impacted by the sale of 4.2 bcf and 2.9 bcf of production in VPP transactions that closed on May 1, 2008 and August 1, 2008, respectively.

(b) The Current Quarter was impacted by the sale of 3.0 bcf and 1.1 bcf of production in the BP Arkoma and BP Fayetteville divestitures, respectively.

(c) The Current Quarter was impacted by the sale of 4.6 bcf of production in a VPP transaction that closed on December 31, 2007.

Natural gas production represented approximately 92% in the Current Quarter and approximately 91% in the Prior Quarter of our total production volume on a natural gas equivalent basis.

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.038 billion in natural gas and oil marketing sales in the Current Quarter, with corresponding natural gas and oil marketing expenses of $1.014 billion, for a net margin before depreciation of $24 million. This compares to sales of $501 million, expenses of $483 million and a net margin before depreciation of $18 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in natural gas and oil marketing net margin due to the increase in production on Chesapeake-operated wells and an increase in natural gas and oil prices.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired and leased. Chesapeake recognized $45 million in service operations revenue in the Current Quarter with corresponding service operations expense of $37 million, for a net margin before depreciation of $8 million. This compares to revenue of $34 million, expenses of $23 million and a net margin before depreciation of $11 million in the Prior Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $239 million in the Current Quarter compared to $165 million in the Prior Quarter. On a unit-of-production basis, production expenses were $1.12 per mcfe in the Current Quarter compared to $0.89 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. We expect that production expenses for the fourth quarter of 2008 will range from $1.00 to $1.15 per mcfe produced.

Production Taxes. Production taxes were $87 million in the Current Quarter compared to $56 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.41 per mcfe in the Current Quarter compared to $0.30 per mcfe in the Prior Quarter. The $31 million increase in production taxes in the Current Quarter is due to an increase in production of 27 bcfe and an increase in the realized average sales price of natural gas and oil of $3.31 per mcfe (excluding gains or losses on derivatives).

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for the fourth quarter of 2008 to range from $0.30 to $0.35 per mcfe based on NYMEX prices ranging from $6.50 to $7.50 per mcf of natural gas and oil prices of $60.00 per barrel.

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General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $108 million in the Current Quarter and $62 million in the Prior Quarter. General and administrative expenses were $0.50 and $0.33 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of increasing labor costs due to the company s continued growth as well as increased media and advocacy expenditures. Included in general and administrative expenses is stock-based compensation of $26 million and $19 million for the Current Quarter and Prior Quarter, respectively. This increase was mainly due to an increase in the number of unvested restricted shares outstanding during the Current Quarter. We anticipate that general and administrative expenses for the fourth quarter of 2008 will be between $0.43 and $0.50 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.13 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 5 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $101 million and $76 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $480 million and $479 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 $2.25 and $2.57 in the Current Quarter and in the Prior Quarter, respectively. The $0.32 decrease in the average DD&A rate is due primarily to our sales of proved undeveloped leasehold at attractive prices with no corresponding decrease in proved reserves. We expect the DD&A rate for the fourth quarter of 2008 to be between $2.25 and $2.30 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $48 million in the Current Quarter and $44 million in the Prior Quarter. Depreciation and amortization of other assets was $0.23 and $0.24 per mcfe for the Current Quarter and the Prior Quarter, respectively. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 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 company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect the fourth quarter of 2008 depreciation and amortization of other assets to be between $0.20 and $0.25 per mcfe produced.

Interest and Other Income (Expense). Interest and other income (expense) was ($2) million in the Current Quarter compared to $1 million in the Prior Quarter. The Current Quarter consisted of $5 million of interest income, ($17) million related to equity investments, a $6 million gain on sale of assets and $4 million of miscellaneous income. The Prior Quarter income consisted of $2 million of interest income, ($3) million related to equity investments and $2 million of miscellaneous income.

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Interest Expense. Interest expense decreased to $48 million in the Current Quarter compared to $116 million in the Prior Quarter as follows:

	Three Months Ended September 30, 2008	2007
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 173	$ 161
Capitalized interest	(128)	(67)
Realized (gain) loss on interest rate derivatives	5	(1)
Unrealized (gain) loss on interest rate derivatives	(8)	19
Amortization of loan discount and other	6	4
Total interest expense	$ 48	$ 116
Average long-term borrowings	$ 10,929	$ 8,724

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.26 per mcfe in the Current Quarter compared to $0.52 in the Prior Quarter. The decrease in interest expense per mcfe is primarily due to increased production volumes and an increase in capitalized interest. Capitalized interest increased by $61 million as a result of a significant increase in unevaluated properties, the base on which interest is capitalized in the Current Quarter compared to the Prior Quarter. We expect interest expense for the fourth Quarter of 2008 to be between $0.30 and $0.35 per mcfe produced (before considering the effect of interest rate derivatives).

Consent Solicitation Fees. During the Current Quarter, we completed a consent solicitation to amend certain provisions contained in five of our senior note indentures. We paid each holder of the notes who delivered a valid consent prior to the expiration of the consent solicitation a cash consent fee of $3.75 for each $1,000 in principal amount of notes in respect of which such consent was delivered. As a result, we incurred consent solicitation fees of $10 million in the Current Quarter.

Loss on Repurchase of Chesapeake Senior Notes. In the Current Quarter, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Income Tax Expense. Chesapeake recorded income tax expense of $2.074 billion in the Current Quarter, compared to income tax expense of $228 million in the Prior Quarter. Of the income tax expense recorded in the Current Quarter, $193 million is reflected as current income tax expense and $1.881 billion is reflected as deferred income tax expense. The divestitures that closed during the Current Quarter are projected to generate sufficient taxable income for the year to exhaust all of our non-limited NOLs and result in a current tax liability for the tax year ended December 31, 2008. Of the $1.846 billion increase in income tax expense recorded in the Current Quarter, $1.819 billion was the result of the increase in net income before income taxes and $27 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Quarter and 38% in the Prior Quarter. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Results of Operations Nine Months Ended September 30, 2008 vs. September 30, 2007

General. For the Current Period, Chesapeake had net income of $1.584 billion, or $2.73 per diluted common share, on total revenues of $8.648 billion. This compares to net income of $1.148 billion, or $2.23 per diluted common share, on total revenues of $5.711 billion during the Prior Period.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were $5.587 billion compared to $4.164 billion in the Prior Period. In the Current Period, Chesapeake produced 629.7 bcfe at a weighted average price of $8.75 per mcfe, compared to 510.1 bcfe produced in the Prior Period at a weighted average price of $8.39 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of $80 million and ($113) million in the Current Period and Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $227 million and increased production resulted in a $1.003 billion increase, for a total increase in revenues of $1.230 billion (excluding unrealized gains or losses on natural gas and oil derivatives). The increase in production from the Prior Period to the Current Period was primarily generated from the drillbit.

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For the Current Period, we realized an average price per mcf of natural gas of $8.41, compared to $8.15 in the Prior Period (weighted average prices for both periods discussed exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $75.82 and $65.55 in the Current Period and Prior Period, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net decrease in natural gas and oil revenues of $454 million, or $0.72 per mcfe, in the Current Period and a net increase of $916 million, or $1.80 per mcfe, in the Prior Period.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flow. 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 $58 million and $56 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 $8 million 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 Nine Months Ended September 30,			
	2008		2007	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent[(a)(b)]	317,605	50%	270,655	53%
Barnett Shale	128,998	21	59,162	12
Permian and Delaware Basins	59,167	9	45,529	9
South Texas and Texas Gulf Coast	53,528	9	58,609	11
Ark-La-Tex	43,983	7	41,279	8
Appalachian Basin[(c)]	26,374	4	34,845	7
Total production	629,655	100%	510,079	100%

(a) The Current Period was impacted by the sale of 7.0 bcf and 2.9 bcf of production in VPP transactions that closed on May 1, 2008 and August 1, 2008, respectively.

(b) The Current Period was impacted by the sale of 3.0 bcf and 1.1 bcf of production in the BP Arkoma and BP Fayetteville divestitures, respectively.

(c) The Current Period was impacted by the sale of 13.8 bcf of production in a VPP transaction that closed on December 31, 2007.

Natural gas production represented approximately 92% of our total production volume on a natural gas equivalent basis in both the Current Period and in the Prior Period.

Natural Gas and Oil Marketing Sales and Operating Expenses. Natural gas and oil marketing activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $2.934 billion in natural gas and oil marketing sales in the Current Period, with corresponding natural gas and oil marketing expenses of $2.864 billion, for a net margin before depreciation of $70 million. This compares to sales of $1.446 billion, expenses of $1.394 billion and a net margin before depreciation of $52 million in the Prior Period. In the Current Period, Chesapeake realized an increase in natural gas and oil marketing net margin related to the increase in production on Chesapeake-operated wells and an increase in natural gas and oil prices.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of assets and businesses we acquired and leased. Chesapeake recognized $127 million in service operations revenue in the Current Period with corresponding service operations expense of $104 million, for a net margin before depreciation of $23 million. This compares to revenue of $101 million, expenses of $67 million and a net margin before depreciation of $34 million in the Prior Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $658 million in the Current Period compared to $461 million in the Prior Period. On a unit-of-production basis, production expenses were $1.04 per mcfe in the Current Period compared to $0.90 per mcfe in the Prior Period. The increase in the Current Period was primarily due to higher third-party field service costs, energy costs, fuel costs, ad valorem taxes and personnel costs. We expect that production expenses for the fourth quarter of 2008 will range from $1.00 to $1.15 per mcfe produced.

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Production Taxes. Production taxes were $250 million in the Current Period compared to $151 million in the Prior Period. On a unit-of-production basis, production taxes were $0.40 per mcfe in the Current Period compared to $0.30 per mcfe in the Prior Period. The $99 million increase in production taxes in the Current Period is due to an increase in production of 120 bcfe and an increase in the realized average sales price of natural gas and oil of $2.88 per mcfe (excluding gains or losses on derivatives).

In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher. We expect production taxes for the fourth quarter of 2008 to range from $0.30 to $0.35 per mcfe based on NYMEX prices ranging from $6.50 to $7.50 per mcf of natural gas and oil prices of $60.00 per barrel.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding internal costs capitalized to our natural gas and oil properties, were $288 million in the Current Period and $168 million in the Prior Period. General and administrative expenses were $0.46 and $0.33 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of increasing labor costs due to the company s continued growth as well as increased media and advocacy expenditures. Included in general and administrative expenses is stock-based compensation of $66 million and $41 million for the Current Period and Prior Period, respectively. This increase was mainly due to an increase in the number of unvested restricted shares outstanding during the Current Period. We anticipate that general and administrative expenses for the fourth quarter of 2008 will be between $0.43 and $0.50 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.13 per mcfe).

Our stock-based compensation for employees and non-employee directors is in the form of restricted stock. Prior to 2004, stock-based compensation awards were only in the form of stock options. Employee stock-based compensation awards generally vest over a period of four or five years. Our non-employee director awards vest over a period of three years. The discussion of stock-based compensation in Note 5 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our restricted stock and stock options.

Chesapeake follows the full-cost method of accounting under which all costs associated with natural gas and oil property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our acquisition, exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $268 million and $186 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our natural gas and oil property acquisition, exploration and development efforts.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.518 billion and $1.314 billion 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 $2.41 and $2.58 in the Current Period and in the Prior Period, respectively. The $0.17 decrease in the average DD&A rate is due primarily to our sales of proved undeveloped leasehold at attractive prices with no corresponding decrease in proved reserves. We expect the DD&A rate for the fourth quarter of 2008 to be between $2.25 and $2.30 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $125 million in the Current Period and $120 million in the Prior Period. Depreciation and amortization of other assets was $0.20 and $0.24 per mcfe for the Current Period and the Prior Period, respectively. The decrease per mcfe in the Current Period was primarily due to higher production volume and sale/leaseback transactions involving drilling rigs and natural gas compressors. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over 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 company-owned drilling rigs and equipment are used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration or development costs. We expect the fourth quarter of 2008 depreciation and amortization of other assets to be between $0.20 and $0.25 per mcfe produced.

Interest and Other Income (Expense). Interest and other income (expense) was ($13) million in the Current Period compared to $12 million in the Prior Period. The Current Period consisted of $9 million of interest income, ($34) million related to equity investments, a $7 million gain on sale of assets and $5 million of miscellaneous income. The Prior Period consisted of $6 million of interest income, $2 million related to equity investments and $4 million of miscellaneous income.

Interest Expense. Interest expense decreased to $212 million in the Current Period compared to $279 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2008	2007
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 509	$ 443
Capitalized interest	(307)	(192)
Realized (gain) loss on interest rate derivatives	1	
Unrealized (gain) loss on interest rate derivatives	(9)	13
Amortization of loan discount and other	18	15
Total interest expense	$ 212	$ 279
Average long-term borrowings	$ 9,974	$ 7,999

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.35 per mcfe in the Current Period compared to $0.52 in the Prior Period. The decrease in interest expense per mcfe is due to increased production volumes and an increase in capitalized interest. Capitalized interest increased by $115 million as a result of a significant increase in unevaluated properties, the base on which interest is capitalized in the Current Period compared to the Prior Period. We expect interest expense for the fourth quarter of 2008 to be between $0.30 and $0.35 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Repurchase of Chesapeake Senior Notes. In the Current Period, we repurchased $300 million of our 7.75% Senior Notes due 2015 in order to re-finance a portion of our long-term debt at a lower rate of interest. In connection with the transaction we recorded a $31 million loss which consisted of a $12 million premium and $19 million of discounts, interest rate derivatives and deferred charges associated with the notes.

Consent Solicitation Fees. During the Current Period, we completed a consent solicitation to amend certain provisions contained in five of our senior note indentures. We paid each holder of the notes who delivered a valid consent prior to the expiration of the consent solicitation a cash consent fee of $3.75 for each $1,000 in principal amount of notes in respect of which such consent was delivered. As a result, we incurred consent solicitation fees of $10 million in the Current Period.

Gain on Sale of Investments. In the Prior Period, we sold our 33% limited partnership interest in Eagle Energy Partners I, L.P., which we first acquired in 2003, for proceeds of $126 million and a gain of $83 million.

Income Tax Expense. Chesapeake recorded income tax expense of $991 million in the Current Period, compared to income tax expense of $704 million in the Prior Period. Of the income tax expense recorded in the Current Period, $196 million is reflected as current income tax expense and $795 million is reflected as deferred income tax expense. The divestitures that closed during the Current Period are projected to generate sufficient taxable income for the year to exhaust all of our non-limited NOLs and result in a current tax liability for the tax year ended December 31, 2008. Of the $287 million increase in income tax expense recorded in the Current Period, $274 million was the result of the increase in net income before income taxes and $13 million was the result of an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Period and 38% in the Prior Period. Our effective tax rate fluctuates as a result of the impact of state income taxes and permanent differences.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil 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, 2007 (2007 Form 10-K).

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Effective January 1, 2008, we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements for our financial assets and liabilities measured on a recurring basis. This statement establishes a framework for measuring fair value of assets and liabilities and expands disclosures about fair value measurements. In February 2008, the FASB issued FSP 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities.

SFAS 157 defines fair value as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. Chesapeake uses appropriate valuation techniques based on available inputs, including counterparty quotes, to measure the fair values of its assets and liabilities. Counterparty quotes are generally assessed as a Level 3 input.

As of September 30, 2008, we had a net derivative liability of $74 million, of which $480 million was based on estimates provided by our respective counterparties and reviewed internally using established indexes and other sources and, as such, are classified as a Level 3 fair value measurement. The accounting applicable to our natural gas and oil derivative contracts is discussed in Note 2 and Note 9 of our condensed consolidated financial statements included in Part I of this report.

Recently Issued and Proposed 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 February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. This statement expands the use of fair value measurement and applies to entities that elect the fair value option. The fair value option established by this statement permits all entities to choose to measure eligible items at fair value at specified election dates. This statement is effective as of the beginning of the first fiscal year that begins after November 15, 2007. Since we have not elected to adopt the fair value option for eligible items, SFAS No. 159 has not had an impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of Accounting Research Bulletin No. 51*. This statement requires an entity to separately disclose non-controlling interests as a separate component of equity in the balance sheet and clearly identify on the face of the income statement net income related to non-controlling interests. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141 (R), *Business Combinations*. This statement requires assets acquired and liabilities assumed to be measured at fair value as of the acquisition date, acquisition-related costs incurred prior to the acquisition to be expensed and contractual contingencies to be recognized at fair value as of the acquisition date. This statement is effective for financial statements issued for fiscal years beginning after December 15, 2008. We are currently assessing the impact, if any, the adoption of this statement will have on our financial position, results of operations or cash flows.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133*. This statement changes the disclosure requirements for derivative instruments and hedging activities. The statement requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This statement is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We are currently assessing the impact that adoption of this statement will have on our financial disclosures.

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In May 2008, the FASB issued FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)*. FSP APB 14-1 clarifies that convertible debt instruments that may be settled in cash upon either mandatory or optional conversion (including partial cash settlement) are not addressed by paragraph 12 of APB Opinion No. 14, Accounting for Convertible Debt and Debt issued with Stock Purchase Warrants. The accounting prescribed by FSP APB 14-1 would increase the amount of interest expense required to be recognized with respect to such instruments and, thus, lower reported net income and net income per share of issuers of such instruments. Issuers will have to account for the liability and equity components of the instrument separately and in a manner that reflects interest expense at the interest rate of similar nonconvertible debt. We have three debt series that will be affected by the guidance, our 2.75% Contingent Convertible Senior Notes due 2035, our 2.5% Contingent Convertible Senior Notes due 2037 and our 2.25% Contingent Convertible Senior Notes due 2038. This staff position is effective for financial statements issued for fiscal years and interim periods beginning after December 15, 2008 and must be applied on a retrospective basis. We are currently assessing the impact that adoption of this staff position will have on our consolidated financial position, results of operations or cash flows.

In June 2008, the FASB issued FSP Emerging Issues Task Force (EITF) No. 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. FSP EITF 03-6-1 addresses whether instruments granted in share-based payments transactions are participating securities prior to vesting and therefore need to be included in the earnings allocation in calculating earnings per share under the two-class method described in SFAS No. 128, *Earnings per Share*. FSP EITF No. 03-6-1 requires companies to treat unvested share-based payment awards that have non-forfeitable rights to dividend or dividend equivalents as a separate class of securities in calculating earnings per share. FSP EITF No. 03-6-1 is effective for fiscal years beginning after December 15, 2008; earlier application is not permitted. We are currently evaluating the impact, if any, the adoption of FSP EITF No. 03-6-1 will have on our financial position, results of operations or cash flows.

In October 2008, the FASB issued FSP FAS 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active*. FSP FAS 157-3 clarifies the application of FASB statement No. 157, *Fair Value Measurements*, in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP is effective upon issuance and will not 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 estimates of natural gas and oil reserves, budgeted capital expenditures, asset monetization plans, expected natural gas and oil production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations and expected future expenses. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our 2007 Form 10-K and Item 1A of Part II of this report. They include:

- the volatility of natural gas and oil prices,
- the availability of capital on an economic basis to fund our drilling and leasehold acquisition program, including through planned asset monetization transactions,
- our ability to replace reserves and sustain production,
- our level of indebtedness,

the risk that lenders under our revolving credit facilities will default in funding borrowings as requested,

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- the ability and willingness of counterparties to our commodity derivative contracts to perform their obligations,
- the ability and willingness of our joint venture partners to fund their obligations to pay a portion of our future drilling and completion costs,
- a contraction in the demand for natural gas in the U.S. as a result of deteriorating general economic conditions,
- the strength and financial resources of our competitors,
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating natural gas and oil reserves of acquired properties and associated potential liabilities,
- unsuccessful exploration and development drilling,
- declines in the value of our natural gas and oil properties resulting in ceiling test write-downs,
- lower prices realized on natural gas and oil sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- lower natural gas and oil prices negatively affecting our ability to borrow,
- drilling and operating risks,
- adverse effects of governmental regulation, and
- losses possible from pending or future litigation.

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***

Natural Gas and Oil Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for natural gas and oil. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2008, our natural gas and oil derivative instruments were comprised of swaps, basis protection swaps, knockout swaps, cap-swaps, call options, put options and collars. These instruments allow us to predict with greater certainty the effective natural gas and oil 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.

Basis protection swaps are arrangements that guarantee a price differential for natural gas or oil from a specified delivery point. For Mid-Continent basis protection swaps, which typically 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 typically 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 knockout swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for the possibility to reduce the counterparty s exposure to zero, in any given month, if the floating market price is lower than certain pre-determined knockout prices.

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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.

For call options, Chesapeake receives a 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.

For put options, Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. If the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall. If the market price settles above the fixed price of the put 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. Generally, 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 natural gas and oil prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to natural gas and oil sales in the month of related production.

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

Gains or losses from certain derivative transactions are reflected as adjustments to natural gas and oil sales on the consolidated statements of operations. Realized gains (losses) are included in natural gas and oil sales in the month of related production. 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 natural gas and oil sales. Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows 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 currently recognized in natural gas and oil sales as unrealized gains (losses). The components of natural gas and oil sales for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	**2007**	**2008**	**2007**
	($ in millions)			
Natural gas and oil sales	$ 2,036	$ 1,161	$ 5,961	$ 3,361
Realized gains (losses) on natural gas and oil derivatives	(246)	286	(454)	916
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	4,543	73	134	(21)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	75	(28)	(54)	(92)
Total natural gas and oil sales	$ 6,408	$ 1,492	$ 5,587	$ 4,164

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As of September 30, 2008, we had the following open natural gas and oil derivative instruments (excluding derivatives assumed through our acquisition of CNR in November 2005) designed to hedge a portion of our natural gas and oil production for periods after September 2008:

	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2008 ($ in millions)
Natural Gas (bbtu):								
Swaps:								
Q4 2008	75,762	$ 9.08	$	$	$	Yes	$	$ 115
Q1 2009	49,519	9.67				Yes		82
Q2 2009	57,938	8.97				Yes		63
Q3 2009	58,588	9.14				Yes		57
Q4 2009	58,427	9.56				Yes		55
2010	164,844	9.44				Yes		133
2011	34,435	8.45				Yes		(3)
2012 2017	43,090	8.03				Yes		(14)
Other Swaps[a]:								
Q4 2008	4,600	8.73				No		5
Q1 2009	4,500	10.14				No		9
Q2 2009	4,550	9.86				No		3
Q3 2009	4,600	9.94				No		3
Q4 2009	4,600	10.24				No		4
2010	32,850	9.89				No		(15)
2011	4,500	8.73				No		(4)
Basis Protection Swaps (Mid-Continent):								
Q4 2008	32,094				(0.45)	No		71
Q1 2009	26,873				(0.47)	No		23
Q2 2009	16,457				(0.27)	No		10
Q3 2009	16,821				(0.27)	No		8
Q4 2009	16,953				(0.27)	No		13
2011	45,090				(0.64)	No	(3)	4
2012 2018	57,961				(0.62)	No	(3)	1
Basis Protection Swaps (Appalachian Basin):								
Q4 2008	5,840				0.33	No		
Q1 2009	3,849				0.29	No		(1)
Q2 2009	4,178				0.28	No		
Q3 2009	4,448				0.27	No		
Q4 2009	4,438				0.27	No		
2010	10,199				0.26	No		(1)
2011	12,086				0.25	No		(1)
2012 2022	134				0.11	No		
Knockout Swaps:								
Q4 2008	69,910	9.89	6.25			No	7	128
Q1 2009	78,580	10.26	6.24			No	5	108
Q2 2009	85,230	9.24	6.09			No	6	52
Q3 2009	92,540	9.41	6.15			No	6	27
Q4 2009	99,360	9.87	6.21			No	6	19
2010	321,150	9.78	6.23			No	2	74
2011	138,600	9.74	6.31			No		5
2012	18,300	9.60	6.50			No		(4)
Call Options:								
Q4 2008	23,180			10.45		No	23	(2)

Q1 2009	58,050	11.47	No	35	(10)
Q2 2009	55,965	11.29	No	34	(9)
Q3 2009	56,580	11.31	No	35	(18)
Q4 2009	54,750	11.39	No	34	(29)
2010	250,025	10.78	No	223	(114)
2011 2017	197,270	10.82	No	210	(121)

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	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums ($ in millions)	Fair Value at September 30, 2008 ($ in millions)
Put Options:								
Q1 2009	9,000	$	$ 5.75	$	$	No	$ 1	$ (1)
Q2 2009	9,100		5.75			No	1	(1)
Q3 2009	9,200		5.75			No	1	(2)
Q4 2009	9,200		5.75			No	1	(1)
2010	36,500		5.75			No	3	(5)
Collars:								
Q4 2008	1,220		7.50	10.20		Yes		1
Other Collars:								
Q4 2008	4,610		8.26	10.38		No	4	3
Q1 2009	15,750		5.74/8.05	11.34		No		10
Q2 2009	15,925		5.74/8.05	11.10		No	(1)	11
Q3 2009	16,100		5.74/8.05	11.12		No		9
Q4 2009	16,100		5.74/8.05	11.16		No	(1)	4
2010	25,550		6.00/7.71	11.46		No	21	5
2011 2020	113,230		6.00/7.19	10.31		No	78	(84)
Total Natural Gas							728	675
Oil (mbbls):								
Swaps:								
Q4 2008	598	65.50				Yes		(21)
Q1 2009	135	68.02				Yes		(4)
Q2 2009	137	67.84				Yes		(4)
Q3 2009	138	67.67				Yes		(5)
Q4 2009	138	67.54				Yes		(5)
Knockout Swaps:								
Q4 2008	828	79.08	55.72			No		(18)
Q1 2009	1,935	83.41	58.21			No		(38)
Q2 2009	1,957	83.37	58.21			No		(43)
Q3 2009	1,978	83.32	58.21			No		(46)
Q4 2009	1,978	83.27	58.21			No		(49)
2010	4,745	90.25	60.00			No		(98)
2011	1,095	104.75	60.00			No		(11)
2012	732	109.50	60.00			No		(6)
Cap-Swaps:								
Q4 2008	276	77.60	55.00			No		(6)
Call Options:								
Q4 2008	890			86.43		No	3	(17)
Q1 2009	2,160			122.22		No	(2)	(15)
Q2 2009	2,184			122.22		No	(2)	(16)
Q3 2009	2,208			122.22		No	(2)	(17)
Q4 2009	2,208			122.22		No	(2)	(18)
2010	10,585			131.67		No	(22)	(62)
2011	3,650			185.00		No	36	(16)
2012	3,660			185.00		No	37	(21)
Other Collars:								
2010	730		90.00/80.00	136.40		No		(4)
Total Oil							46	(540)
Total Natural Gas and Oil							$ 774	$ 135

(a) These include options to extend existing swaps for an additional 12 months at 50,000 mmbtu/day at $8.73 mmbtu, callable by the counterparty in March 2009 and March 2010 and 40,000 mmbtu/day at $11.35/mmbtu, callable by the counterparty in December 2009.

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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 natural gas and oil 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 natural gas and oil 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 natural gas and oil 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 remaining as of September 30, 2008:

	Volume	Weighted Average Fixed Price to be Received	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at September 30, 2008 ($ in millions)
Natural Gas (bbtu):						
Swaps:						
Q4 2008	9,660	$ 4.66	$	$	Yes	$ (29)
Q1 2009	4,500	5.18			Yes	(12)
Q2 2009	4,550	5.18			Yes	(12)
Q3 2009	4,600	5.18			Yes	(13)
Q4 2009	4,600	5.18			Yes	(15)
Collars:						
Q1 2009	900		4.50	6.00	Yes	(2)
Q2 2009	910		4.50	6.00	Yes	(2)
Q3 2009	920		4.50	6.00	Yes	(2)
Q4 2009	920		4.50	6.00	Yes	(2)
Total Natural Gas						$ (89)

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 September 30, 2008.

Based upon the market prices at September 30, 2008, we expect to transfer approximately $163 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of September 30, 2008 are expected to mature by December 31, 2022.

Additional information concerning the fair value of our natural gas and oil derivative instruments, including CNR derivatives assumed, is as follows:

	2008 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ (369)

Change in fair value of contracts		166
Fair value of contracts when entered into		(589)
Contracts realized or otherwise settled		454
Fair value of contracts when closed		384
Fair value of contracts outstanding, as of September 30	$	46

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The change in the fair value of our derivative instruments since January 1, 2008 resulted from new contracts entered into, the settlement of derivatives for a realized gain (loss), as well as a decrease in natural gas prices. Derivative instruments reflected as current in the consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for natural gas and oil as of the consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2008	2009	2010	2011	2012 ($ in billions)	Thereafter	Total
Liabilities:							
Long-term debt fixed rate[(a)]	$	$	$	$	$	$ 10.899	$ 10.899
Average interest rate						5.4%	5.4%
Long-term debt variable rate	$	$	$	$	$ 3.474	$	$ 3.474
Average interest rate					4.0%		4.0%

(a) This amount does not include the discount included in long-term debt of ($90) million and the impact of interest rate derivatives of $62 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 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.

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 ($5) million, $1 million, ($1) million and a nominal amount in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Unrealized gains (losses) included in interest expense were $8 million, ($19) million, $9 million and ($13) million in the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

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As of September 30, 2008, the following interest rate derivatives were outstanding:

		Notional Amount ($ in millions)	Weighted Average Fixed Rate	Weighted Average Floating Rate	Weighted Average Cap/Floor Rate	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Fixed to Floating Swaps:								
January 2008	November 2020	$ 1,400	6.81%	6 month LIBOR plus 257 basis points		Yes	$	$ (30)
January 2008	January 2018	$ 500	6.94%	6 month LIBOR plus 290 basis points		No	2	(6)
Floating to Fixed Swaps:								
August 2007	August 2010	$ 825	4.74%	1 3 month LIBOR		No		(14)
Swaption:								
July 2008	October 2008	$ 250	6.50%			No	4	(6)
Call Options:								
January 2008	July 2010	$ 1,000	6.63%			No	9	(18)
Collars:								
August 2007	August 2010	$ 800			5.37% 4.52%	No		(19)
							$ 15	$ (93)

In the Current Period, we sold call options on five of our interest rate swaps and received $12 million in premiums. Three options were exercised in the Current Period resulting in the termination of three interest rate swaps and one call option expired unexercised. Additionally, we sold two swaptions in the Current Period and received $6 million in net premiums. One swaption was exercised during the Current Period and resulted in a new interest swap.

In the Current Period, we closed 32 interest rate swaps for a gain totaling $72 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining term of the related senior notes.

Foreign Currency Derivatives

On December 6, 2006, we issued 600 million of 6.25% Euro-denominated Senior Notes due 2017. Concurrent with the issuance of the Euro-denominated senior notes, we entered into a cross currency swap to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. Under the terms of the cross currency swap, on each semi-annual interest payment date, the counterparties pay Chesapeake 19 million and Chesapeake pays the counterparties $30 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay Chesapeake 600 million and Chesapeake will pay the counterparties $800 million. The terms of the cross currency swap were based on the dollar/euro exchange rate on the issuance date of $1.3325 to 1.00. Through the cross currency swap, we have eliminated any potential variability in Chesapeake s expected cash flows related to changes in foreign exchange rates and therefore the swap qualifies as a cash flow hedge under SFAS 133. The euro-denominated debt is recorded in notes payable ($845 million at September 30, 2008) using an exchange rate of $1.4081 to 1.00. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $27 million at September 30, 2008.

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.

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PART II. OTHER INFORMATION

ITEM 1. ***Legal Proceedings***

Chesapeake is currently involved in various disputes incidental to its business operations. Certain legal actions brought by royalty owners are discussed in Item 3 of our 2007 Form 10-K. Reference also is made to Litigation in Note 3 of the notes to the condensed consolidated financial statements included in Part I, Item 1 of this Form 10-Q, which is incorporated herein by reference. 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 2007 Form 10-K. This information should be considered carefully, together with the additional risk factor described below and other information in this report and other reports and materials we file with the Securities and Exchange Commission.

The financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could adversely affect the collectability of our trade receivables. Market conditions could cause our commodity hedging arrangements to be ineffective if our counterparties are unable to perform their obligations or seek bankruptcy protection. Additionally, the current economic situation could lead to reduced demand for natural gas and oil, or lower prices for natural gas and oil, or both, which could have a negative impact on our revenues.

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 September 30, 2008:

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)]
July 1, 2008 through July 31, 2008	496,087	$ 66.561		
August 1, 2008 through August 31, 2008	9,542	47.537		
September 1, 2008 through September 30, 2008	51,764	37.707		
Total	557,393	$ 63.556		

(a) Includes the deemed surrender to the company of 43,076 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 514,317 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan 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 Current Quarter, a holder of our 2.75% contingent convertible senior notes due 2035 converted $2,000 in principal amount of the notes into $2,000 cash and 8 shares of common stock. The company received notice of conversion on August 4, 2008. The issuance of the shares of common stock was exempt from registration under the Securities Act of 1933 pursuant to Section 3(a)(9) under the Securities Act.

ITEM 3. ***Defaults Upon Senior Securities***

Not applicable.

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

Not applicable.

ITEM 5. ***Other Information***

Not applicable.

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ITEM 6. ***Exhibits***

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

Exhibit Number	Exhibit Description	Form	Incorporated by Reference SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/09/2006	
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.3	08/11/2008	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).					X
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008	
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock, as amended.	10-K	001-13726	3.1.7	02/29/2008	
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	06/13/2007	
4.1.1	Thirteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.					X
4.2.1	Thirteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.					X
4.5.1	Sixteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.					X
4.6.1	Fourteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.					X
4.7.1	Twelfth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.					X
4.8.1	Ninth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.9.1	Eighth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.					X
4.10.1	Ninth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.					X
4.11.1	Eighth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.					X
4.12.1	Eighth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.					X
4.13.1	Fifth Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 7.625% senior notes due 2013.					X
4.14.1	Fourth Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of December 6, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to the 6.25% senior notes due 2017.					X
4.15.1	Third Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of May 15, 2007 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 2.50% contingent convertible senior notes due 2037.					X
4.16.1	First Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of May 27, 2008 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 7.25% senior notes due 2018.					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.17.1	First Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of May 27, 2008 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 2.25% Contingent Convertible Senior Notes due 2038.					X
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X

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SIGNATURES

Pursuant to the requirement 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: November 10, 2008

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INDEX TO EXHIBITS

		Incorporated by Reference				
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/09/2006	
3.1.3	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.3	08/11/2008	
3.1.4	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).					X
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended.	S-8	333-151762	4.1.6	06/18/2008	
3.1.6	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008	
3.1.7	Certificate of Designation of 6.25% Mandatory Convertible Preferred Stock, as amended.	10-K	001-13726	3.1.7	02/29/2008	
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	06/13/2007	
4.1.1	Thirteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.					X
4.2.1	Thirteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.					X
4.5.1	Sixteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.					X
4.6.1	Fourteenth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.					X
4.7.1	Twelfth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.					X
4.8.1	Ninth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.					X

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Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
4.9.1	Eighth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.					X
4.10.1	Ninth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.					X
4.11.1	Eighth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.					X
4.12.1	Eighth Supplemental Indenture dated as of October 14, 2008 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 Mellon Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.					X
4.13.1	Fifth Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 7.625% senior notes due 2013.					X
4.14.1	Fourth Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of December 6, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, The Bank of New York Mellon Trust Company, N.A., as Trustee, AIB/BNY Fund Management (Ireland) Limited, as Irish Paying Agent and Transfer Agent, and The Bank of New York, London Branch, as Registrar, Transfer Agent and Paying Agent, with respect to the 6.25% senior notes due 2017.					X
4.15.1	Third Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of May 15, 2007 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 2.50% contingent convertible senior notes due 2037.					X
4.16.1	First Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of May 27, 2008 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 7.25% senior notes due 2018.					X

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4.17.1	First Supplemental Indenture dated as of October 14, 2008 to Indenture dated as of May 27, 2008 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to the 2.25% Contingent Convertible Senior Notes due 2038.					X
12	Ratios of Earnings to Fixed Charges and Preferred Dividends.					X
31.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X