CHESAPEAKE ENERGY CORP
Form 10-Q
August 09, 2010
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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 June 30, 2010

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

For the transition period from __________ to __________

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

6100 North Western Avenue **Oklahoma City, Oklahoma**	**73118**
(Address of principal executive offices)	(Zip Code)

(405) 848-8000

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 [ ] 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 August 3, 2010, there were 654,329,768 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	June 30, 2010	December 31, 2009
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 601	$ 307
Accounts receivable	1,359	1,325
Short-term derivative instruments	965	692
Deferred income tax asset		24
Other	93	98
Total Current Assets	3,018	2,446
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	36,576	35,007
Unevaluated properties	11,678	10,005
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(24,858)	(24,220)
Total natural gas and oil properties, at cost based on full-cost accounting	23,396	20,792
Other property and equipment:		
Natural gas gathering systems and treating plants	1,699	3,516
Buildings and land	1,711	1,673
Drilling rigs and equipment	752	687
Natural gas compressors	273	325
Other	607	550
Less: accumulated depreciation and amortization of other property and equipment	(608)	(833)
Total other property and equipment	4,434	5,918
Total Property and Equipment	27,830	26,710
OTHER ASSETS:		
Investments	1,047	404
Long-term derivative instruments	10	60
Other assets	264	294
Total Other Assets	1,321	758
TOTAL ASSETS	$ 32,169	$ 29,914

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	June 30, 2010	December 31, 2009
	($ in millions)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,564	$ 957
Short-term derivative instruments	17	27
Accrued liabilities	970	920
Deferred income taxes	337	
Income taxes payable	4	1
Revenues and royalties due others	575	565
Accrued interest	188	218
Total Current Liabilities	3,655	2,688
LONG-TERM LIABILITIES:		
Long-term debt, net	10,501	12,295
Deferred income tax liabilities	1,546	1,059
Long-term derivative instruments	972	787
Asset retirement obligations	285	282
Revenues and royalties due others	82	73
Other liabilities	313	389
Total Long-Term Liabilities	13,699	14,885
CONTINGENCIES AND COMMITMENTS (Note 3)		
EQUITY:		
Chesapeake stockholders equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized:		
5.75% cumulative convertible non-voting preferred stock, 1,500,000 and 0 shares issued and outstanding as of June 30, 2010 and December 31, 2009, respectively, entitled in liquidation to $1.5 billion and $0	1,500	
5.75% cumulative convertible non-voting preferred stock (series A), 1,100,000 and 0 shares issued and outstanding as of June 30, 2010 and December 31, 2009, respectively, entitled in liquidation to $1.1 billion and $0	1,100	
4.50% cumulative convertible preferred stock, 2,558,900 shares issued and outstanding as of June 30, 2010 and December 31, 2009, entitled in liquidation to $256 million	256	256
5.00% cumulative convertible preferred stock (series 2005B), 2,095,615 shares issued and outstanding as of June 30, 2010 and December 31, 2009, entitled in liquidation to $209 million	209	209
5.00% cumulative convertible preferred stock (series 2005), 0 and 5,000 shares issued and outstanding as of June 30, 2010 and December 31, 2009, entitled in liquidation to $0 and $1 million		1
Common stock, $0.01 par value, 1,000,000,000 shares authorized, 651,996,688 and 648,549,165 shares issued at June 30, 2010 and December 31, 2009, respectively	7	6
Paid-in capital	12,096	12,146
Retained earnings (deficit)	(410)	(1,261)
Accumulated other comprehensive income, net of tax of ($45) million and ($62) million, respectively	75	102
Less: treasury stock, at cost; 993,966 and 877,205 common shares as of June 30, 2010 and December 31, 2009, respectively	(18)	(15)
Total Chesapeake Stockholders Equity	14,815	11,444
Noncontrolling interest		897

Total Equity	14,815	12,341
TOTAL LIABILITIES AND EQUITY	$ 32,169	$ 29,914

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	($ in millions, except per share data)			
REVENUES:				
Natural gas and oil sales	$ 1,161	$ 1,097	$ 3,059	$ 2,494
Marketing, gathering and compression sales	793	532	1,637	1,084
Service operations revenue	58	44	114	90
Total Revenues	2,012	1,673	4,810	3,668
OPERATING COSTS:				
Production expenses	213	213	421	451
Production taxes	37	24	85	46
General and administrative expenses	106	74	215	164
Marketing, gathering and compression expenses	763	500	1,578	1,023
Service operations expense	53	46	102	87
Natural gas and oil depreciation, depletion and amortization	340	295	647	742
Depreciation and amortization of other assets	53	58	103	115
Impairment of natural gas and oil properties and other assets		5		9,635
Restructuring costs		34		34
Total Operating Costs	1,565	1,249	3,151	12,297
INCOME (LOSS) FROM OPERATIONS	447	424	1,659	(8,629)
OTHER INCOME (EXPENSE):				
Interest (expense) income	16	(22)	(9)	(8)
Loss on redemptions or exchanges of Chesapeake debt	(69)	(2)	(71)	(2)
Impairment of investments		(10)		(162)
Other income (expense)	20	(2)	35	5
Total Other Income (Expense)	(33)	(36)	(45)	(167)
INCOME (LOSS) BEFORE INCOME TAXES	414	388	1,614	(8,796)
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	5	1	5	1
Deferred income taxes	154	144	616	(3,299)
Total Income Tax Expense (Benefit)	159	145	621	(3,298)
NET INCOME (LOSS)	255	243	993	(5,498)
Net (income) loss attributable to noncontrolling interest				
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	255	243	993	(5,498)

Preferred stock dividends	(20)	(6)	(25)	(12)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ 235	$ 237	$ 968	$ (5,510)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.37	$ 0.39	$ 1.54	$ (9.18)
Diluted	$ 0.37	$ 0.39	$ 1.49	$ (9.18)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.075	$ 0.15	$ 0.15
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	631	603	630	600
Diluted	635	610	665	600

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 993	$ (5,498)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	750	857
Deferred income tax expense (benefit)	616	(3,299)
Unrealized losses on derivatives	5	29
Realized gains on financing derivatives	(271)	(35)
Stock-based compensation	67	68
Accretion of discount on contingent convertible notes	38	40
Loss on equity investments	35	8
Loss on redemptions or exchanges of Chesapeake debt	39	2
Impairment of natural gas and oil properties and other assets		9,630
Impairment of investments		162
Restructuring costs		29
Other	22	12
Change in assets and liabilities	684	(7)
Cash provided by operating activities	2,978	1,998
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(2,331)	(2,108)
Acquisitions of natural gas and oil proved and unproved properties	(2,855)	(710)
Additions to other property and equipment	(679)	(980)
Proceeds from divestitures of proved and unproved properties	1,431	187
Proceeds from sales of volumetric production payments	502	41
Proceeds from sale of other assets	306	104
Proceeds from (additions to) investments	(109)	2
Other	3	(1)
Cash used in investing activities	(3,732)	(3,465)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	7,044	3,363
Payments on credit facilities borrowings	(7,415)	(4,166)
Proceeds from issuance of preferred stock, net of offering costs	2,562	
Proceeds from issuance of senior notes, net of offering costs		1,346
Cash paid to redeem Chesapeake debt	(1,334)	
Cash paid for common stock dividends	(95)	(89)
Cash paid for preferred stock dividends	(11)	(12)
Realized gains on financing derivatives	271	9
Proceeds from sale/leaseback of real estate surface assets		145
Proceeds from mortgage of building		54
Net increase (decrease) in outstanding payments in excess of cash balance	47	(350)
Other	(21)	(28)
Cash provided by financing activities	1,048	272
Net increase (decrease) in cash and cash equivalents	294	(1,195)

Cash and cash equivalents, beginning of period	307	1,749
Cash and cash equivalents, end of period	$ 601	$ 554

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)

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 57	$ 2
Income taxes, net of refunds received	$ (291)	$ 176

SUPPLEMENTAL SCHEDULE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:

As of June 30, 2010 and 2009, dividends payable on our common and preferred stock were $90 million and $51 million, respectively.

For the six months ended June 30, 2010 and 2009, natural gas and oil properties were adjusted by $64 million and ($65) million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

For the six months ended June 30, 2010 and 2009, other property and equipment were adjusted by $2 million and ($12) million, respectively, as a result of an increase (decrease) in accrued costs.

We recorded non-cash asset additions (reductions) to natural gas and oil properties of ($3) million and ($2) million for the six months ended June 30, 2010 and 2009, respectively, for asset retirement obligations.

During the six months ended June 30, 2010, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $11 million in aggregate principal amount for an aggregate of 298,500 shares of our common stock in privately negotiated exchanges.

On May 3, 2010, we converted all 5,000 shares of our outstanding 5.00% Cumulative Convertible Preferred Stock (Series 2005) into 20,774 shares of common stock pursuant to the company s mandatory conversion rights.

During the six months ended June 30, 2009, we issued 15,823,838 shares of common stock, valued at $269 million, for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

During the six months ended June 30, 2009, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $85 million in aggregate principal amount for an aggregate of 2,530,650 shares of our common stock in privately negotiated exchanges.

On June 15, 2009, we converted all 143,768 shares of our outstanding 6.25% Mandatory Convertible Preferred Stock into 1,239,538 shares of common stock.

On March 31, 2009, we converted all 3,033 shares of our outstanding 4.125% Cumulative Convertible Preferred Stock into 182,887 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 EQUITY

(Unaudited)

	Six Months Ended June 30, 2010	2009
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$ 466	$ 505
Issuance of 1,500,000 and 0 shares of 5.75% preferred stock	1,500	
Issuance of 1,100,000 and 0 shares of 5.75% preferred stock (series A)	1,100	
Exchange of 5,000 and 0 shares of 5.00% preferred stock (series 2005) for common stock	(1)	
Exchange of 0 and 143,768 shares of 6.25% preferred stock for common stock		(36)
Exchange of 0 and 3,033 shares of 4.125% preferred stock for common stock		(3)
Balance, end of period	3,065	466
COMMON STOCK:		
Balance, beginning of period	6	6
Issuance of 0 and 15,823,838 shares of common stock for the purchase of proved and unproved properties		
Exchange of convertible notes for 298,500 and 2,530,650 shares of common stock		
Exchange of preferred stock for 20,774 and 1,422,425 shares of common stock		
Stock-based compensation	1	
Balance, end of period	7	6
PAID-IN CAPITAL:		
Balance, beginning of period	12,146	11,680
Issuance of 0 and 15,823,838 shares of common stock for the purchase of proved and unproved properties		254
Exchange of convertible notes for 298,500 and 2,530,650 shares of common stock	8	54
Exchange of 5,000 and 146,801 shares of preferred stock for common stock	1	39
Stock-based compensation	116	119
Exercise of stock options	2	1
Offering expenses	(38)	
Dividends on common stock	(95)	(91)
Dividends on preferred stock	(44)	(12)
Tax benefit (reduction in tax benefit) from exercise of stock-based compensation		(12)
Balance, end of period	12,096	12,032
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	(1,261)	4,569
Net income (loss)	993	(5,498)
Cumulative effect of accounting change, net of income taxes of $89 million	(142)	
Balance, end of period	(410)	(929)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	102	267
Hedging activity	(19)	110
Investment activity	(8)	61

Balance, end of period	75	438
TREASURY STOCK COMMON:		
Balance, beginning of period	(15)	(10)
Purchase of 123,579 and 64,242 shares for company benefit plans	(3)	(1)
Release of 6,818 and 2,718 shares for company benefit plans		
Balance, end of period	(18)	(11)
TOTAL CHESAPEAKE STOCKHOLDERS EQUITY	14,815	12,002
NONCONTROLLING INTEREST:		
Balance, beginning of period	897	
Deconsolidation of investment in CMP	(897)	
Balance, end of period		
TOTAL EQUITY	$ 14,815	$ 12,002

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	($ in millions)			
Net income (loss)	$ 255	$ 243	$ 993	$ (5,498)
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of ($38) million, $37 million, $114 million and $333 million	(62)	63	187	547
Reclassification of gain on settled contracts, net of income taxes of ($82) million, ($120) million, ($135) million and ($232) million	(134)	(197)	(221)	(381)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of $7 million, ($13) million, $9 million and ($34) million	11	(22)	15	(56)
Unrealized (gain) loss on marketable securities, net of income taxes of ($3) million, $7 million, ($5) million and $11 million	(5)	12	(8)	18
Reclassification of loss on investments, net of income taxes of $0, $0, $0 and $26 million				43
Comprehensive income (loss)	65	99	966	(5,327)
(Income) loss attributable to noncontrolling interest				
Comprehensive income (loss) available to Chesapeake	$ 65	$ 99	$ 966	$ (5,327)

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 (SEC). Chesapeake s annual report on Form 10-K for the year ended December 31, 2009 (2009 Form 10-K) includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three and six months ended June 30, 2010 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and six months ended June 30, 2010 (the Current Quarter and the Current Period , respectively) and the three and six months ended June 30, 2009 (the Prior Quarter and the Prior Period , respectively).

Cumulative Effect of Accounting Change

Beginning January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we no longer consolidate our midstream joint venture, Chesapeake Midstream Partners, L.L.C. Because we share control 50/50 with our joint venture partner, Global Infrastructure Partners, our investment in the joint venture is now accounted for under the equity method (See Note 9). Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our condensed consolidated statement of equity for the Current Period. This charge reflects the difference between the carrying value of our initial investment in the joint venture, which was recorded at carryover basis as an entity under common control, and the fair value of our equity in the joint venture as of the formation date.

Critical Accounting Policies

We consider accounting policies related to hedging, natural gas and oil properties and income taxes to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our 2009 Form 10-K.

2. Financial Instruments and Hedging Activities

Natural Gas and Oil Derivatives

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. 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 our risk management objectives. As of June 30, 2010 and December 31, 2009, our natural gas and oil derivative instruments were comprised of the following types of instruments:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Collars: These instruments 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 put and the call strike price, no payments are due from either party. Three-way collars include an additional put option in exchange for a more favorable strike price on the collar. This eliminates the counterparty s downside exposure below the second put option.

Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.

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.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin 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.

All of our derivative instruments are net settled based on the difference between the fixed-price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

The estimated fair values of our natural gas and oil derivative instruments as of June 30, 2010 and December 31, 2009 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	June 30, 2010		December 31, 2009	
	Volume	**Fair Value ($ in millions)**	**Volume**	**Fair Value ($ in millions)**
Natural gas (bbtu):				
Fixed-price swaps	565,288	$ 1,150	492,053	$ 662
Fixed-price collars	14,660	39	74,240	92
Call options	1,244,630	(548)	996,750	(541)
Put options	(65,940)	(52)	(69,620)	(50)
Fixed-price knockout swaps	28,530	12	38,370	17
Basis protection swaps	120,663	(48)	125,469	(50)
Total natural gas	1,907,831	553	1,657,262	130
Oil (mbbl):				
Fixed-price swaps	9,148	(5)	5,475	3
Call options	38,912	(451)	14,975	(144)
Fixed-price knockout swaps	4,219	50	6,572	32
Total oil	52,279	(406)	27,022	(109)
Total estimated fair value		$ 147		$ 21

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following this guidance, 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 accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). 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 natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	($ in millions)			
Natural gas and oil sales	$ 984	$ 717	$ 2,169	$ 1,495
Realized gains (losses) on natural gas and oil derivatives	573	597	972	1,115
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(378)	(253)	(58)	(206)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(18)	36	(24)	90
Total natural gas and oil sales	$ 1,161	$ 1,097	$ 3,059	$ 2,494

Based upon the market prices at June 30, 2010, we expect to transfer approximately $196 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of June 30, 2010 are expected to mature by December 31, 2022.

We have a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 5.6 tcfe of trading capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. As of June 30, 2010, we had hedged a total of 2.1 tcfe under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and bank credit facilities, we enter into interest rate derivatives. As of June 30, 2010 and December 31, 2009, our interest rate derivative instruments were comprised of the following types of instruments:

Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and pay a fixed interest rate) to manage our interest rate exposure related to our bank credit facilities borrowings.

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

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(Unaudited)

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap on a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

The notional amount of debt hedged and the estimated fair value of our interest rate derivatives outstanding as of June 30, 2010 and December 31, 2009 are provided below.

	June 30, 2010		December 31, 2009	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 2,125	$ (27)	$ 2,925	$ (113)
Collars	250	(1)	250	(6)
Call options	250	(14)	250	(2)
Swaptions	400	(1)	500	(11)
Totals	$ 3,025	$ (43)	$ 3,925	$ (132)

For interest rate derivative instruments designated as fair value hedges, the fair values of the hedges are recorded on the condensed consolidated balance sheets as assets or liabilities, with corresponding offsetting adjustments to the debt s carrying value. Changes in the fair value of non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are currently reported in the condensed consolidated statements of operations as unrealized (gains) losses within interest expense.

Realized gains or losses from interest rate derivative transactions are reflected as adjustments to interest expense in the condensed consolidated statements of operations. The components of interest expense for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	($ in millions)			
Interest expense on senior notes	$ (190)	$ (196)	$ (383)	$ (378)
Interest expense on credit facilities	(12)	(17)	(24)	(29)
Capitalized interest	179	152	340	314
Realized gains (losses) on interest rate derivatives	2	5	4	12
Unrealized gains (losses) on interest rate derivatives	49	42	77	87
Amortization of loan discount and other	(12)	(8)	(23)	(14)
Total interest (expense) income	$ 16	$ (22)	$ (9)	$ (8)

Our qualifying interest rate swaps are considered 100% effective and therefore no ineffectiveness was recorded for the periods presented above.

Gains and losses related to terminated qualifying interest rate derivative transactions will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next ten years, we will be recognizing $92 million in gains related to such transactions.

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.

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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. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $118 million at June 30, 2010. The euro-denominated debt in notes payable has been adjusted to $738 million at June 30, 2010 using an exchange rate of $1.2291 to 1.00.

Additional Disclosures Regarding Derivative Instruments and Hedging Activities

In accordance with accounting guidance for derivatives and hedging, 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. Derivative instruments reflected as current in the condensed consolidated balance sheet represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices/rates as of the balance sheet date. The derivative settlement amounts are not due until the month in which the related underlying hedged transaction occurs. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all cash settlements are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.

The following table sets forth the fair value of each classification of derivative instrument as of June 30, 2010 and December 31, 2009, on a gross basis without regard to same-counterparty netting:

		Fair Value	
	Balance Sheet Location	June 30, 2010	December 31, 2009
		($ in millions)	
ASSET DERIVATIVES:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 454	$ 417
Commodity contracts	Long-term derivative instruments	57	36
Foreign currency contracts	Long-term derivative instruments		43
Total		511	496
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	568	318
Commodity contracts	Long-term derivative instruments	200	66
Interest rate contracts	Long-term derivative instruments	18	
Total		786	384
LIABILITY DERIVATIVES:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments		(1)
Interest rate contracts	Long-term derivative instruments		(11)
Foreign currency contracts	Long-term derivative instruments	(118)	
Total		(118)	(12)

Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(57)	(42)
Commodity contracts	Long-term derivative instruments	(1,075)	(768)
Interest rate contracts	Short-term derivative instruments	(17)	(27)
Interest rate contracts	Long-term derivative instruments	(44)	(94)
Total		(1,193)	(931)
Total derivative instruments		$ (14)	$ (63)

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(Unaudited)

A consolidated summary of the effect of derivative instruments on the condensed consolidated statements of operations for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period is provided below, separating fair value, cash flow and non-qualifying derivatives.

The following table presents the gain (loss) recognized in net income (loss) for instruments designated as fair value derivatives ($ in millions):

		Three Months Ended June 30,		Six Months Ended June 30,	
Fair Value Derivatives	**Location of Gain (Loss)**	**2010**	**2009**	**2010**	**2009**
Interest rate contracts	Interest expense[a]	$ 5	$ 10	$ 13	$ 18

(a) Interest expense on items hedged during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period was $5 million, $20 million, $15 million and $33 million, respectively, which is included in interest expense on the condensed consolidated statements of operations.

The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) and recognized in net income (loss), including any hedge ineffectiveness, for derivative instruments designated as cash flow derivatives ($ in millions):

		Three Months Ended June 30,		Six Months Ended June 30,	
Cash Flow Derivatives	**Location of Gain (Loss)**	**2010**	**2009**	**2010**	**2009**
Gain (Loss) Recognized in AOCI (Effective Portion)					
Commodity contracts	AOCI	$ (41)	$ 30	$ 364	$ 712
Foreign exchange contracts	AOCI	(41)	35	(39)	78
		$ (82)	$ 65	$ 325	$ 790
Gain (Loss) Reclassified from AOCI (Effective Portion)					
Commodity contracts	Natural gas and oil sales	$ 216	$ 317	$ 356	$ 613
		$ 216	$ 317	$ 356	$ 613
Gain (Loss) Recognized (Ineffective Portion and Amount Excluded from Effectiveness Testing)[a]					
Commodity contracts	Natural gas and oil sales	$ 18	$ 36	$ 48	$ 90
		$ 18	$ 36	$ 48	$ 90

(a) In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, the amount of gain (loss) recognized in net income (loss) represents ($18) million, $36 million, ($24) million and $90 million related to the ineffective portion of our cash flow derivatives and $36 million, $0, $72 million and $0, respectively, related to the amount excluded from the assessment of hedge effectiveness.

The following table presents the gain (loss) recognized in net income (loss) for instruments not qualifying as cash flow or fair value derivatives ($ in millions):

		Three Months Ended June 30,		Six Months Ended June 30,	
Non-Qualifying Derivatives	**Location of Gain (Loss)**	**2010**	**2009**	**2010**	**2009**
Commodity contracts	Natural gas and oil sales	$ (57)	$ 27	$ 486	$ 296
Interest rate contracts	Interest expense	46	37	68	81
	Total	$ (11)	$ 64	$ 554	$ 377

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Concentration of Credit Risk

A significant portion of our credit risk is concentrated in derivative instruments that enable us to hedge a portion of our exposure to natural gas and oil prices, interest rate volatility and exchange rate exposure. 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 we attempt to limit our exposure to non-performance by any single counterparty. On June 30, 2010, our derivative instruments were spread among 14 counterparties. Additionally, our multi-counterparty secured hedging facility described previously includes 13 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We use this facility for all of our commodity hedging.

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 monitor the creditworthiness of all our counterparties. 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. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period we recognized $0, $5 million, $0 and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

3. Contingencies and Commitments

Litigation

On February 25, 2009, a putative class action was filed in the U.S. District Court for the Southern District of New York against the company and certain of its officers and directors along with certain underwriters of the company s July 2008 common stock offering. Following the appointment of a lead plaintiff and counsel, the plaintiff filed an amended complaint on September 11, 2009 alleging that the registration statement for the offering contained material misstatements and omissions and seeking damages under Sections 11, 12 and 15 of the Securities Act of 1933 of an unspecified amount and rescission. The action was transferred to the U.S. District Court for the Western District of Oklahoma on October 13, 2009. The company has filed a motion to dismiss which has been fully briefed. A derivative action was also filed in the District Court of Oklahoma County, Oklahoma on March 10, 2009 against the company s directors and certain of its officers alleging breaches of fiduciary duties relating to the disclosure matters alleged in the securities case. The derivative action is stayed pending resolution of the motion to dismiss in the class action.

On March 26, 2009, a shareholder filed a petition in the District Court of Oklahoma County, Oklahoma seeking to compel inspection of company books and records relating to compensation of the company s CEO. On August 20, 2009, the court denied the inspection demand, dismissed the petition and entered judgment in favor of Chesapeake. The shareholder is appealing the court s ruling in the Court of Civil Appeals of the State of Oklahoma.

Three derivative actions were filed in the District Court of Oklahoma County, Oklahoma on April 28, May 7, and May 20, 2009 against the company s directors alleging breaches of fiduciary duties relating to compensation of the company s CEO and alleged insider trading, among other things, and seeking unspecified damages, equitable relief and disgorgement. These three derivative actions were consolidated and a Consolidated Derivative Shareholder Petition was filed on June 23, 2009. Chesapeake is named as a nominal defendant. Chesapeake has filed a motion to dismiss which was heard on February 1, 2010. On February 28, 2010, the court ordered that plaintiffs claims be dismissed and granted plaintiffs leave to file an amended petition within 90 days. Plaintiffs chose not to amend and on April 9, 2010, at plaintiffs request, the court entered an order certifying that the February 28, 2010 dismissal was a final, appealable order. Plaintiffs are appealing the dismissal. By the order of the Oklahoma Supreme Court dated June 16, 2010, the appeal was assigned to the Court of Civil Appeals.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

It is inherently difficult to predict the outcome of litigation, and we are currently unable to estimate the amount of any potential liabilities associated with the foregoing cases, which are all in preliminary stages.

Chesapeake is also involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The company has satisfactorily resolved most of the suits but a few remain pending. In one case, following trial, plaintiffs have requested reconsideration of the judgment entered in favor of Chesapeake on June 11, 2010. The company believes that it has substantial defenses to the claims made in all these cases.

The company records an associated liability when a loss is probable and the amount is reasonably estimable. Although the outcome of litigation cannot be predicted with certainty, management is of the opinion that no pending or threatened lawsuit or dispute incidental to its business operations is likely to have a material adverse effect on the company s consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management s estimates.

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 an initial term of five years which commenced in 2008 and is automatically extended for one additional year on each December 31 unless the company provides 30 days notice of non-extension. The agreement contains a cap on annual cash salary and bonus compensation at 2008 levels through 2013. 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, or in the event of his incapacity, death or retirement at or after age 55. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2012. The agreements with our COO, CFO and other executive vice presidents contain a cap on annual cash salary for the three-year term of the agreement. In addition, annual cash bonuses will not exceed the sum of the individual EVP s cash bonus compensation for (a) the last half of 2008 and (b) the first half of 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 receive a lump sum payment equal to 26 weeks of cash salary 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. The agreements also provide for a 2008 incentive award payable in four equal annual installments, the first of which was paid on September 30, 2009. The payment of each installment of the award is subject to the individual s continued employment on the date of payment, except that the unpaid installments of the award would be accelerated and paid in a lump sum in the event of a change of control or a termination of employment without cause, a voluntary termination by the executive due to a material breach of contract by the company, or termination due to incapacity or death.

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.

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(Unaudited)

The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at June 30, 2010.

Rig Leases

In a series of transactions in 2006, 2007 and 2008, our drilling subsidiaries sold 83 drilling rigs and related equipment for $677 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 $93 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 is being 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 payment equal to the fair market rental value of the rigs as determined at the time of renewal. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2010, the minimum aggregate undiscounted future rig lease payments were approximately $476 million.

Compressor Leases

Through various transactions since 2007 our compression subsidiary sold 2,189 compressors, a significant portion of its compressor fleet, for $497 million and entered into a master lease agreement. The term of the agreement varies by buyer ranging from four to ten years for aggregate lease payments of approximately $73 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 is being amortized to marketing, gathering and compression expenses over the lease term. Under the leases, we can exercise an early purchase option 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. Commitments related to compressor lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2010, the minimum aggregate undiscounted future compressor lease payments were approximately $434 million.

Transportation Contracts

Chesapeake has various firm pipeline transportation service agreements with expiration dates ranging from 2010 to 2099. 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. The aggregate undiscounted amounts of such required demand payments as of June 30, 2010 were as follows ($ in millions):

2010	$	147
2011		350
2012		377
2013		362
2014		343
2015 2099		2,478

Total	$	4,057

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Drilling Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 41 rigs with terms of six months to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of June 30, 2010, the aggregate undiscounted drilling rig commitment was approximately $238 million.

Natural Gas and Oil 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 any natural gas and oil associated with certain volumetric production payment transactions. The purchase commitments are based on market prices at the time of production, and the purchased natural gas and oil is resold.

Minimum Volume Commitments

At June 30, 2010, we were a party to a gas gathering agreement with Chesapeake Midstream Partners, L.L.C. (see Note 9) pursuant to which we committed to deliver specified minimum volumes of natural gas from our Barnett Shale production annually through December 31, 2018 and for the six-month period ending June 30, 2019. Effective August 3, 2010, a subsidiary of Chesapeake Midstream Partners L.P. (see Note 14) became our counterparty to this agreement. At the end of the term or annually, Chesapeake will be invoiced for any shortfalls in such volume commitments at the rate specified in the agreement. Volume commitments remaining as of June 30, 2010 are as follows:

	Bcf
2010	198
2011	313
2012	325
2013	338
2014	351
After 2014	1,686
Total	3,211

In addition, Chesapeake has entered into commitments to deliver 630 bcf from July 2010 through September 2021 to third-party midstream companies.

Net Acreage Maintenance Commitments

Under the terms of our joint development agreements with our joint venture partners Statoil and Total, we are required to extend, renew or replace certain expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas.

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4. Net Income Per Share

Accounting guidance for earnings per share (EPS) requires presentation of basic and diluted earnings per share on the face of the statements of operations for all entities with complex capital structures as well as a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

For the Current Period, no securities were antidilutive in the calculation of diluted EPS. The following securities and associated adjustments to net income comprised of dividends and losses on conversions/exchanges were not included in the calculation of diluted EPS for the Current Quarter, the Prior Quarter and the Prior Period, as the effect was antidilutive.

	Shares (in millions)	Net Income Adjustments ($ in millions)
Three Months Ended June 30, 2010:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	16	$ 6
5.75% cumulative convertible preferred stock (series A)	19	$ 8
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 3
4.50% cumulative convertible preferred stock	6	$ 3
Three Months Ended June 30, 2009:		
Common stock equivalent of our preferred stock outstanding:		
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 3
4.50% cumulative convertible preferred stock	6	$ 3
Six Months Ended June 30, 2009:		
Outstanding stock options	1	$
Unvested restricted stock	4	$
Common stock equivalent of our preferred stock outstanding:		
4.50% cumulative convertible preferred stock	6	$ 6
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 5
Common stock equivalent of our preferred stock outstanding prior to conversion:		
6.25% mandatory convertible preferred stock	1	$ 1

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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A reconciliation of basic EPS and diluted EPS for the Current Quarter, the Prior Quarter and the Current Period is as follows:

	Income (Numerator)	Weighted Average Shares (Denominator)	Per Share Amount
	(in millions, except per share data)		
Three Months Ended June 30, 2010:			
Basic EPS	$ 235	631	$ 0.37
Effect of Dilutive Securities:			
Employee stock options		1	
Restricted stock		3	
Diluted EPS	$ 235	635	$ 0.37
Three Months Ended June 30, 2009:			
Basic EPS	$ 237	603	$ 0.39
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common shares assumed issued for 6.25% cumulative convertible preferred stock		1	
Employee stock options		1	
Restricted stock		5	
Diluted EPS	$ 237	610	$ 0.39
Six Months Ended June 30, 2010:			
Basic EPS	$ 968	630	$ 1.54
Effect of Dilutive Securities:			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 5.75% cumulative convertible preferred stock	6	8	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	8	10	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	5	6	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	6	6	
Employee stock options		1	
Restricted stock		4	
Diluted EPS	$ 993	665	$ 1.49

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(Unaudited)

5. Stockholders Equity, Restricted Stock and Stock Options

Common Stock

The following is a summary of the changes in our common shares issued for the six months ended June 30, 2010 and 2009:

	2010	2009
	(in thousands)	
Shares issued at January 1	648,549	607,953
Stock option exercises	316	157
Restricted stock issuances (net of forfeitures)	2,812	2,365
Convertible note exchanges	299	2,531
Preferred stock conversions/exchanges	21	1,422
Common stock issued for the purchase of proved and unproved properties		15,824
Shares issued at June 30	651,997	630,252

In the Current Period, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 80% of the face value of the notes. In connection with accounting guidance for debt with conversion and other options, we are required to account for the liability and equity components of our convertible debt instruments separately. Of the $11 million principal amount of convertible notes exchanged in the Current Quarter, $7 million was allocated to the debt component and the remaining $4 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss, (including a nominal amount of deferred charges associated with the exchanges).

In the Prior Period, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock valued at approximately $53 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 63% of the face value of the notes. Of the $85 million principal amount of convertible notes exchanged in the Prior Period, $52 million was allocated to the debt component and the remaining $33 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss, (including $1 million of deferred charges associated with the exchanges that were written off).

In the Prior Period, we issued 15,823,838 shares of common stock, valued at $269 million, for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Preferred Shares

The following is a summary of the changes in our preferred shares outstanding for the six months ended June 30, 2010 and 2009:

	5.75%	5.75%(A)	4.50%	5.00% (2005B)	5.00% (2005)	6.25%	4.125%
				($ in thousands)			
Shares outstanding at January 1, 2010			2,559	2,096	5		
Preferred stock issuances	1,500	1,100					
Conversion of preferred into common stock					(5)		
Shares outstanding at June 30, 2010	1,500	1,100	2,559	2,096			
Shares outstanding at January 1, 2009			2,559	2,096	5	144	3
Conversion of preferred into common stock						(144)	(3)
Shares outstanding at June 30, 2009			2,559	2,096	5		

On May 17, 2010, we issued 600,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock, par value $0.01 per share and liquidation preference $1,000 per share, in a private placement for net proceeds of approximately $594 million. We issued an additional 900,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock on June 18, 2010, upon the exercise of the purchasers option to place the additional shares, for net proceeds of approximately $877 million.

On May 17, 2010, we issued 1,100,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock (Series A), par value $0.01 per share and liquidation preference $1,000 per share, in a private placement for net proceeds of approximately $1.091 billion.

On May 3, 2010, we converted all 5,000 shares of our outstanding 5.00% Cumulative Convertible Preferred Stock (Series 2005) into 20,774 shares of common stock pursuant to the company s mandatory conversion rights.

On June 15, 2009, we converted all 143,768 shares of our outstanding 6.25% Mandatory Convertible Preferred Stock into 1,239,538 shares of common stock pursuant to the company s mandatory conversion rights.

On March 31, 2009, we converted all 3,033 shares of our outstanding 4.125% Cumulative Convertible Preferred Stock into 182,887 shares of common stock pursuant to the company s mandatory conversion rights.

Dividends

Dividends declared on our common stock and preferred stock are reflected as adjustments to retained earnings to the extent a surplus of retained earnings will exist after giving effect to the dividends. To the extent retained earnings are insufficient to fund the distributions, such payments constitute a return of contributed capital rather than earnings and are accounted for as a reduction to paid-in capital.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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, marketing, gathering and compression 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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	($ in millions)			
Natural gas and oil properties	$ 28	$ 29	$ 66	$ 58
General and administrative expenses	21	19	42	39
Production expenses	9	9	18	17
Marketing, gathering and compression expenses	4	4	9	8
Service operations expense	2	2	4	4
Total	$ 64	$ 63	$ 139	$ 126

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 (in thousands)	Weighted-Average Grant-Date Fair Value
Unvested shares as of January 1, 2010	19,225	$ 31.89
Granted	4,354	$ 27.74
Vested	(2,719)	$ 28.32
Forfeited	(550)	$ 31.79
Unvested shares as of June 30, 2010	20,310	$ 31.48

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $70 million based on the stock price at the time of vesting.

As of June 30, 2010, there was $408 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.25 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 a reduction in tax benefits related to restricted stock of $1 million, $5 million, $1 million and $12 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

Stock Options. We granted stock options prior to 2006 under several stock compensation plans. Outstanding options expire ten years from the date of grant and vested over a four-year period. All stock options outstanding are fully vested and exercisable.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

The following table provides information related to stock option activity during the Current Period:

	Number of Shares Underlying Options (in thousands)	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a] ($ in millions)
Outstanding at January 1, 2010	2,283	$ 8.36	2.75	$ 40
Exercised	(316)	$ 6.10		
Expired		$		
Outstanding at June 30, 2010	1,967	$ 8.72	2.44	$ 24
Exercisable at June 30, 2010	1,967	$ 8.72	2.44	$ 24

(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.

During the Current Period, we recognized excess tax benefits related to stock options of $1 million, which was recorded as an adjustment to additional paid-in capital and deferred income taxes. Nominal amounts of excess tax benefits related to stock options were recorded as adjustments to additional paid-in capital and deferred income taxes in the Current Quarter, the Prior Quarter and the Prior Period.

6. Debt

Our total debt consisted of the following at June 30, 2010 and December 31, 2009:

	June 30, 2010	December 31, 2009
	($ in millions)	
7.5% senior notes due 2013	$	$ 364
7.625% senior notes due 2013	500	500
7.0% senior notes due 2014[a]	300	300
7.5% senior notes due 2014		300
6.375% senior notes due 2015[b]	600	600
9.5% senior notes due 2015	1,425	1,425
6.625% senior notes due 2016[a]	600	600
6.875% senior notes due 2016		670
6.25% Euro-denominated senior notes due 2017[c]	738	860
6.5% senior notes due 2017	1,100	1,100
6.25% senior notes due 2018[a]	600	600

7.25% senior notes due 2018	800	800
6.875% senior notes due 2020	500	500
2.75% contingent convertible senior notes due 2035[d]	451	451
2.5% contingent convertible senior notes due 2037[d]	1,378	1,378
2.25% contingent convertible senior notes due 2038[d]	752	763
Corporate revolving bank credit facility	1,371	1,892
Midstream revolving bank credit facility	150	
Midstream joint venture revolving bank credit facility[e]		44
Discount on senior notes[f]	(832)	(921)
Interest rate derivatives[g]	68	69
Total notes payable and long-term debt	$ 10,501	$ 12,295

(a) Subsequent to June 30, 2010, we commenced a tender offer for these notes. See Note 14 for further discussion.

(b) These notes were called for redemption on June 21, 2010 and redeemed on July 22, 2010 utilizing funds from our corporate revolving credit facility.

(c) The principal amount shown is based on the dollar/euro exchange rate of $1.2291 to 1.00 and $1.4332 to 1.00 as of June 30, 2010 and December 31, 2009, respectively. See Note 2 for information on our related foreign currency derivatives.

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(d) 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 when 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 second quarter of 2010, 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 third quarter of 2010 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	$ 48.71	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 64.26	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 107.36	June 14, 2019

(e) Effective January 1, 2010, our midstream joint venture was no longer consolidated in accordance with the new authoritative guidance. See Note 1 for further details.

(f) Included in this discount is $751 million at June 30, 2010 and $794 million at December 31, 2009 associated with the equity component of our contingent convertible senior notes.

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

Senior Notes

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries. See Note 12 for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. 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.

We are required to account for the liability and equity components of our convertible debt instruments separately and to reflect interest expense at the interest rate of similar nonconvertible debt at the time of issuance. These rates for 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 are 6.86%, 8.0% and 8.0%, respectively.

On June 21, 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Current Period.

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On June 21, 2010, we called for redemption in whole for a redemption price of approximately $619 million, plus accrued interest, $600 million in principal amount of our 6.375% Senior Notes due 2015. This redemption occurred on July 22, 2010.

During the Current Period, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $11 million in aggregate principal amount for an aggregate of 298,500 shares of our common stock in privately negotiated exchanges. Associated with these exchanges, we recognized a loss of $2 million in the Current Period.

No scheduled principal payments are required under our senior notes until 2013 when $500 million is due.

Bank Credit Facilities

We utilize two bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility[a]	Midstream Credit Facility[b]
	($ in millions)	
Borrowing capacity	$ 3,500	$ 250
Maturity date	November 2012	September 2012
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of June 30, 2010	$ 1,371	$ 150
Letters of credit outstanding as of June 30, 2010	$ 14	$

(a) Borrowers are Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C., a wholly owned subsidiary of Chesapeake Midstream Development, L.P. Certain terms of the credit agreement for this facility were amended on August 2, 2010. See Note 14.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, none of our credit 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.

Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A. or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.00% to 0.75% per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% 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 of 0.50%. 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. It was amended during the Current Quarter to, among other things, bring in additional lenders to replace Lehman Brothers unfunded commitment. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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(Unaudited)

indebtedness to total capitalization ratio was 0.35 to 1 and our indebtedness to EBITDA ratio was 2.64 to 1 at June 30, 2010. 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 Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned restricted subsidiaries.

Midstream Credit Facility

Our $250 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. Borrowings under the midstream credit facility are secured by all of the assets of the wholly owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted 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 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 1.03 to 1 and our EBITDA to interest expense coverage ratio was 19.77 to 1 at June 30, 2010. If CMD or its restricted 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 facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

Other Financings

In 2009, we financed 113 real estate surface assets in the Barnett Shale area for approximately $145 million and entered into a 40-year master lease agreement under which we agreed to lease the sites for approximately $15 million to $27 million annually. This lease transaction was recorded as a financing lease and the cash received was recorded with an offsetting long-term liability on the condensed consolidated balance sheet. Chesapeake exercised its option to repurchase two of the assets in the Current Period. As of June 30, 2010, 111 assets were leased and the minimum aggregate undiscounted future lease payments were approximately $836 million.

In 2009, we financed our regional Barnett Shale headquarters building in Fort Worth, Texas for net proceeds of approximately $54 million with a five-year term loan which has a floating rate of prime plus 275 basis points. At our option, we may prepay in full without penalty beginning in year four. The payment obligation is guaranteed by Chesapeake.

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7. Segment Information

In accordance with accounting guidance for 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 midstream 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. The midstream segment is responsible for marketing, gathering and compression of 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. Our drilling rig and trucking service operations are presented in Other Operations in the table below.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the midstream segment s sale of natural gas and oil related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $926 million, $622 million, $1.933 billion and $1.293 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period. The following table presents selected financial information for Chesapeake s operating segments.

	Exploration and Production	Midstream	Other Operations ($ in millions)	Intercompany Eliminations	Consolidated Total
Three Months Ended June 30, 2010:					
Revenues	$ 1,161	$ 1,719	$ 181	$ (1,049)	$ 2,012
Intersegment revenues		(926)	(123)	1,049	
Total revenues	$ 1,161	$ 793	$ 58	$	$ 2,012
Income (loss) before income taxes	$ 403	$ 23	$ (14)	$ 2	$ 414
Three Months Ended June 30, 2009:					
Revenues	$ 1,097	$ 1,154	$ 115	$ (693)	$ 1,673
Intersegment revenues		(622)	(71)	693	
Total revenues	$ 1,097	$ 532	$ 44	$	$ 1,673
Income (loss) before income taxes	$ 408	$ 11	$ (14)	$ (17)	$ 388
Six Months Ended June 30, 2010:					
Revenues	$ 3,059	$ 3,570	$ 351	$ (2,170)	$ 4,810
Intersegment revenues		(1,933)	(237)	2,170	
Total revenues	$ 3,059	$ 1,637	$ 114	$	$ 4,810
Income (loss) before income taxes	$ 1,579	$ 55	$ (25)	$ 5	$ 1,614

Six Months Ended June 30, 2009:					
Revenues	$ 2,494	$ 2,377	$ 269	$ (1,472)	$ 3,668
Intersegment revenues		(1,293)	(179)	1,472	
Total revenues	$ 2,494	$ 1,084	$ 90	$	$ 3,668
Income (loss) before income taxes	$ (8,785)	$ 29	$ (34)	$ (6)	$ (8,796)
As of June 30, 2010:					
Total assets	$ 28,963	$ 3,180	$ 703	$ (677)	$ 32,169
As of December 31, 2009:					
Total assets	$ 25,637	$ 4,323	$ 660	$ (706)	$ 29,914

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8. Divestitures

Joint Ventures

In January 2010, Chesapeake and Total E&P USA, Inc., a wholly owned subsidiary of Total S.A. (NYSE: TOT, FP: FP) (Total), closed a $2.25 billion Barnett Shale joint venture transaction, whereby Total acquired a 25% interest in our upstream Barnett Shale assets. Total paid us approximately $800 million in cash at closing and will pay an additional $1.45 billion over time by funding 60% of our share of future drilling and completion expenditures. We expect this drilling carry to be fully utilized by year-end 2012.

During the Current Period, as part of our joint venture agreements with Statoil and Plains Exploration & Production Company, we sold an interest in additional leasehold in the Marcellus and Haynesville shale plays for approximately $320 million.

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

During the Current Period, we received the benefit of approximately $534 million in drilling carries associated with the Barnett ($299 million) and Marcellus ($235 million) joint ventures. In the Prior Period, we received the benefit of approximately $580 million in drilling carries associated with the Fayetteville ($337 million), the Haynesville ($204 million) and the Marcellus ($39 million) joint ventures.

Volumetric Production Payment

On February 5, 2010, we sold certain Chesapeake-operated long-lived producing assets in East Texas and the Texas Gulf Coast in our sixth volumetric production payment (VPP) transaction for net proceeds of approximately $180 million, or $3.95 per mcfe.

On June 14, 2010, we sold certain Chesapeake-operated long-lived producing assets in the Permian Basin in our seventh VPP transaction for proceeds of approximately $335 million, or $8.73 per mcfe.

For accounting purposes, cash proceeds from these transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized and our proved reserves were reduced accordingly.

Other Divestitures

In the Current Quarter, we sold producing properties and gathering systems in Virginia and in the Permian Basin for proceeds of approximately $330 million.

9. Investments

At June 30, 2010, investments accounted for under the equity method totaled $1.021 billion and investments accounted for under the cost method totaled $26 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	Carrying Value June 30, 2010	Carrying Value December 31, 2009
			($ in millions)	

Chesapeake Midstream Partners, L.L.C.	50%	Equity	$ 559	$
Private oilfield services company	25%	Equity	333	239
Chaparral Energy, Inc.	21%	Equity	103	103
Gastar Exploration Ltd.	14%	Cost	24	32
Other		Cost/Equity	28	30
			$ 1,047	$ 404

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Chesapeake Midstream Partners, L.L.C. On September 30, 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, Chesapeake contributed certain natural gas gathering and processing assets to a new joint venture entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP. The assets we contributed to the joint venture were substantially all of our midstream assets in the Barnett Shale and also the majority of our non-shale midstream assets in the Arkoma, Anadarko, Delaware and Permian Basins. During the fourth quarter of 2009, CMP was consolidated within our financial statements. Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we no longer consolidate our midstream joint venture. Because we share control 50/50 with GIP, our midstream joint venture is now accounted for under the equity method. Adoption of this new guidance resulted in an after-tax cumulative effect charge to retained earnings of $142 million, which is reflected in our condensed consolidated statement of equity for the six months ended June 30, 2010. This charge reflects the difference between the carrying value of our initial investment in the joint venture, which was recorded at carryover basis as an entity under common control, and the fair value of our equity in the joint venture as of the formation date. In May 2010, we received a $75 million cash distribution from the joint venture. The carrying value of our investment in the joint venture is less than our underlying equity in net assets by approximately $286 million as of June 30, 2010. This difference is being accreted over 20 years.

Private oilfield services company. The carrying value of our investment in a private oilfield services company is in excess of our underlying equity in net assets by approximately $157 million as of June 30, 2010. This excess amount is attributed to certain intangibles associated with the specialty services provided by the private oilfield services company and is being amortized over the estimated life of the intangibles.

Chaparral Energy, Inc. The carrying value of our investment in Chaparral is in excess of our underlying equity in net assets by approximately $38 million as of June 30, 2010. This excess is attributed to the natural gas and oil reserves held by Chaparral and is being amortized over the estimated life of these reserves based on a unit of production rate.

10. Restructuring

In the Prior Period, we restructured our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model the company uses elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the reorganization include termination benefits, consolidating or closing facilities and relocating employees. In addition, we had certain other workforce reductions that resulted in termination benefits. A summary of Chesapeake s restructuring cost is presented below ($ in millions):

	Six Months Ended June 30, 2009
Termination and relocation costs	$ 22
Acceleration of restricted stock awards	9
Other associated costs	3
Total Restructuring Costs	$ 34

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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11. Fair Value Measurements

Certain financial instruments are reported at fair value on the condensed consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined 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 a market valuation approach based on available inputs, which may or may not be observable in the market, to measure the fair values of its assets and liabilities.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2010 ($ in millions):

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Cash equivalents	$ 601	$	$	$ 601
Investments	24			24
Other long-term assets	36			36
Long-term debt			(738)	(738)
Other long-term liabilities	(36)			(36)
Derivatives:				
Commodity assets		1,177	102	1,279
Commodity liabilities			(1,132)	(1,132)
Interest rate assets			18	18
Interest rate liabilities			(61)	(61)
Foreign currency liabilities			(118)	(118)
Total derivatives		1,177	(1,191)	(14)
Total	$ 625	$ 1,177	$ (1,929)	$ (127)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2009 ($ in millions):

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				

Cash equivalents	$ 307	$	$	$ 307
Investments	32			32
Other long-term assets	34			34
Long-term debt			(1,398)	(1,398)
Other long-term liabilities	(34)			(34)
Derivatives:				
Commodity assets		693	143	836
Commodity liabilities		(1)	(809)	(810)
Interest rate liabilities			(132)	(132)
Foreign currency assets			43	43
Total derivatives		692	(755)	(63)
Total	$ 339	$ 692	$ (2,153)	$ (1,122)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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 obligations under our Deferred Compensation Plan, is based on quoted market prices.

Derivatives. The fair values of our commodity derivatives are based on a third-party pricing model which utilizes inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparties for reasonableness. Since the commodity swaps do not have options and therefore no unobservable inputs, they are classified as Level 2. All other commodity derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. For interest rate and foreign currency derivatives, we use the fair value estimates provided by our respective counterparties, which are classified as Level 3 inputs. These values are reviewed internally for reasonableness using future interest rate curves and time to maturity. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. We factor in the non-performance risk in the valuation of our derivatives using current published credit default swaps rates. To date this has not had a material impact on the values of our derivatives.

Debt. The fair value of certain of our long-term debt is based on the face amount of that debt along with the value of the related interest rate swaps.

A summary of the changes in Chesapeake s assets (liabilities) classified as Level 3 measurements during the Current Period and the Prior Period is presented below ($ in millions):

		Derivatives		
	Commodity	Interest Rate	Foreign Currency	Debt
Balance of Level 3 as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses) (realized/unrealized):				
Included in earnings (realized)[a]	214	(5)		
Included in earnings or change in net assets (unrealized)[a]	(453)	88	(122)	110
Included in other comprehensive income (loss)	(10)		(39)	
Purchases, issuances and settlements	(115)	6		550 [b]
Transfers in and out of Level 3				
Balance of Level 3 as of June 30, 2010	$ (1,030)	$ (43)	$ (118)	$ (738)
Balance of Level 3 as of January 1, 2009	$ 431	$ (63)	$ (76)	$ (1,470)
Total gains (losses) (realized/unrealized):				
Included in earnings (realized)[a]	459	12		
Included in earnings or change in net assets (unrealized)[a]	(148)	87	6	(59)
Included in other comprehensive income (loss)	93		77	
Purchases, issuances and settlements	(571)	(179)		(1,000)[b]
Transfers in and out of Level 3				

Balance of Level 3 as of June 30, 2009	$	264	$	(143)	$	7	$ (2,529)

(a) Amounts related to commodity derivatives are included in Natural Gas and Oil Sales, and amounts related to interest rate and foreign currency derivatives and debt are included in Interest Expense.

(b) Amount represents a(n) (increase)/decrease in debt recorded at fair value as a result of new or terminated interest rate swaps.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

Fair Value of Other Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term debt and our convertible preferred stock primarily using quoted market prices. Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	June 30, 2010		December 31, 2009	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 10,433	$ 10,853	$ 12,226	$ 12,824
Convertible preferred stock	$ 3,065	$ 2,980	$ 466	$ 401

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible notes listed in Note 6 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our midstream subsidiary, CMD, is not a guarantor and is subject to covenants in the midstream revolving credit facility referred to in Note 6 that restricts it from paying dividends or distributions or making loans to Chesapeake.

Set forth below are condensed consolidating financial statements for Chesapeake Energy Corporation (the parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of June 30, 2010 and December 31, 2009 and for the three and six months ended June 30, 2010 and 2009. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the subsidiaries operated as independent entities.

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 601	$	$	$ 601
Other	3	2,311	193	(90)	2,417
Total Current Assets	3	2,912	193	(90)	3,018
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		23,173	223		23,396
Other property and equipment, net		2,973	1,461		4,434
Total Property and Equipment		26,146	1,684		27,830
Other assets	158	599	564		1,321
Investments in subsidiaries and intercompany advance	694	64		(758)	
TOTAL ASSETS	$ 855	$ 29,721	$ 2,441	$ (848)	$ 32,169
CURRENT LIABILITIES:					
Current liabilities	$ 353	$ 3,279	$ 113	$ (90)	$ 3,655
Intercompany payable (receivable) from parent	(23,744)	21,498	2,145	101	
Total Current Liabilities	(23,391)	24,777	2,258	11	3,655

LONG-TERM LIABILITIES:					
Long-term debt, net	8,980	1,371	150		10,501
Deferred income tax liabilities	428	1,250	(31)	(101)	1,546
Other liabilities	23	1,629			1,652
Total Long-Term Liabilities	9,431	4,250	119	(101)	13,699
EQUITY:					
Chesapeake stockholders equity	14,815	694	64	(758)	14,815
Noncontrolling interest					
Total Equity	14,815	694	64	(758)	14,815
TOTAL LIABILITIES AND EQUITY	$ 855	$ 29,721	$ 2,441	$ (848)	$ 32,169

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET

AS OF DECEMBER 31, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 293	$ 14	$	$ 307
Other	27	2,031	166	(85)	2,139
Total Current Assets	27	2,324	180	(85)	2,446
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		20,788	4		20,792
Other property and equipment, net		2,903	3,015		5,918
Total Property and Equipment		23,691	3,019		26,710
Other assets	197	540	21		758
Investments in subsidiaries and intercompany advance	3,029	222		(3,251)	
TOTAL ASSETS	$ 3,253	$ 26,777	$ 3,220	$ (3,336)	$ 29,914
CURRENT LIABILITIES:					
Current liabilities	$ 277	$ 2,261	$ 235	$ (85)	$ 2,688
Intercompany payable (receivable) from parent	(19,388)	17,508	1,793	87	
Total Current Liabilities	(19,111)	19,769	2,028	2	2,688
LONG-TERM LIABILITIES:					
Long-term debt, net	10,359	1,892	44		12,295
Deferred income tax liabilities	393	727	26	(87)	1,059
Other liabilities	168	1,360	3		1,531
Total Long-Term Liabilities	10,920	3,979	73	(87)	14,885
EQUITY:					
Chesapeake stockholders equity	11,444	3,029	222	(3,251)	11,444
Noncontrolling interest			897		897

Total Equity	11,444	3,029	1,119	(3,251)	12,341
TOTAL LIABILITIES AND EQUITY	$ 3,253	$ 26,777	$ 3,220	$ (3,336)	$ 29,914

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,161	$	$	$ 1,161
Marketing, gathering and compression sales		768	62	(37)	793
Service operations revenue		58			58
Total Revenues		1,987	62	(37)	2,012
OPERATING COSTS:					
Production expenses		213			213
Production taxes		37			37
General and administrative expenses		99	7		106
Marketing, gathering and compression expenses		751	32	(20)	763
Service operations expense		53			53
Natural gas and oil depreciation, depletion and amortization		340			340
Depreciation and amortization of other assets		41	12		53
Total Operating Costs		1,534	51	(20)	1,565
INCOME (LOSS) FROM OPERATIONS		453	11	(17)	447
OTHER INCOME (EXPENSE):					
Interest (expense) income	(140)	(33)	(1)	190	16
Loss on redemptions or exchanges of Chesapeake debt	(69)				(69)
Other income (expense)	190	7	13	(190)	20
Equity in net earnings of subsidiary	267	14		(281)	
Total Other Income (Expense)	248	(12)	12	(281)	(33)
INCOME (LOSS) BEFORE INCOME TAXES	248	441	23	(298)	414
INCOME TAX EXPENSE (BENEFIT)	(7)	164	9	(7)	159
NET INCOME (LOSS)	255	277	14	(291)	255
Net income (loss)attributable to noncontrolling interest					
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 255	$ 277	$ 14	$ (291)	$ 255

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

THREE MONTHS ENDED JUNE 30, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,097	$	$	$ 1,097
Marketing, gathering and compression sales		467	118	(53)	532
Service operations revenue		44			44
Total Revenues		1,608	118	(53)	1,673
OPERATING COSTS:					
Production expenses		213			213
Production taxes		24			24
General and administrative expenses		68	6		74
Marketing, gathering and compression expenses		450	46	4	500
Service operations expense		46			46
Natural gas and oil depreciation, depletion and amortization		295			295
Depreciation and amortization of other assets		36	22		58
Impairment of natural gas and oil properties and other assets		(4)	9		5
Restructuring costs		34			34
Total Operating Costs		1,162	83	4	1,249
INCOME (LOSS) FROM OPERATIONS		446	35	(57)	424
OTHER INCOME (EXPENSE):					
Interest (expense) income	(159)	(36)	(2)	175	(22)
Impairment of investments		(10)			(10)
Loss on redemptions or exchanges of Chesapeake debt	(2)				(2)
Other income (expense)	175	(1)	(1)	(175)	(2)
Equity in net earnings of subsidiary	235	(16)		(219)	
Total Other Income (Expense)	249	(63)	(3)	(219)	(36)
INCOME (LOSS) BEFORE INCOME TAXES	249	383	32	(276)	388
INCOME TAX EXPENSE (BENEFIT)	6	150	12	(23)	145
NET INCOME (LOSS)	243	233	20	(253)	243
Net income (loss) attributable to noncontrolling interest					
	$ 243	$ 233	$ 20	$ (253)	$ 243

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 3,059	$	$	$ 3,059
Marketing, gathering and compression sales		1,581	110	(54)	1,637
Service operations revenue		114			114
Total Revenues		4,754	110	(54)	4,810
OPERATING COSTS:					
Production expenses		421			421
Production taxes		85			85
General and administrative expenses		202	13		215
Marketing, gathering and compression expenses		1,544	54	(20)	1,578
Service operations expense		102			102
Natural gas and oil depreciation, depletion and amortization		647			647
Depreciation and amortization of other assets		81	22		103
Total Operating Costs		3,082	89	(20)	3,151
INCOME (LOSS) FROM OPERATIONS		1,672	21	(34)	1,659
OTHER INCOME (EXPENSE):					
Interest (expense) income	(298)	(92)	(2)	383	(9)
Loss on redemptions or exchanges of Chesapeake debt	(71)				(71)
Other income (expense)	383		35	(383)	35
Equity in net earnings of subsidiary	984	33		(1,017)	
Total Other Income (Expense)	998	(59)	33	(1,017)	(45)
INCOME (LOSS) BEFORE INCOME TAXES	998	1,613	54	(1,051)	1,614
INCOME TAX EXPENSE (BENEFIT)	5	608	21	(13)	621
NET INCOME (LOSS)	993	1,005	33	(1,038)	993
Net income (loss)attributable to noncontrolling interest					
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 993	$ 1,005	$ 33	$ (1,038)	$ 993

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

SIX MONTHS ENDED JUNE 30, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 2,494	$	$	$ 2,494
Marketing, gathering and compression sales		956	228	(100)	1,084
Service operations revenue		90			90
Total Revenues		3,540	228	(100)	3,668
OPERATING COSTS:					
Production expenses		452	(1)		451
Production taxes		46			46
General and administrative expenses		153	11		164
Marketing, gathering and compression expenses		919	94	10	1,023
Service operations expense		87			87
Natural gas and oil depreciation, depletion and amortization		742			742
Depreciation and amortization of other assets	(1)	74	41	1	115
Impairment of natural gas and oil properties and other assets		9,621	14		9,635
Restructuring costs		34			34
Total Operating Costs	(1)	12,128	159	11	12,297
INCOME (LOSS) FROM OPERATIONS	1	(8,588)	69	(111)	(8,629)
OTHER INCOME (EXPENSE):					
Interest (expense) income	(286)	(54)	(5)	337	(8)
Impairment of investments		(162)			(162)
Loss on redemptions or exchanges of Chesapeake debt	(2)				(2)
Other income (expense)	337	3	2	(337)	5
Equity in net earnings of subsidiary	(5,529)	(28)		5,557	
Total Other Income (Expense)	(5,480)	(241)	(3)	5,557	(167)
INCOME (LOSS) BEFORE INCOME TAXES	(5,479)	(8,829)	66	5,446	(8,796)
INCOME TAX EXPENSE (BENEFIT)	19	(3,300)	25	(42)	(3,298)
NET INCOME (LOSS)	(5,498)	(5,529)	41	5,488	(5,498)
Net income (loss) attributable to noncontrolling interest					
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (5,498)	$ (5,529)	$ 41	$ 5,488	$ (5,498)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

SIX MONTHS ENDED JUNE 30, 2010

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 2,874	$ 104	$	$ 2,978
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(4,967)	(219)		(5,186)
Proceeds from divestitures of natural gas and oil properties		1,933			1,933
Additions to other property and equipment		(323)	(356)		(679)
Other investing activities		90	110		200
Cash used in investing activities		(3,267)	(465)		(3,732)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		6,725	319		7,044
Payments on credit facilities borrowings		(7,247)	(168)		(7,415)
Proceeds from preferred stock, net of offering costs	2,562				2,562
Cash paid to redeem Chesapeake debt	(1,334)				(1,334)
Other financing activities	(128)	324	(5)		191
Intercompany advances, net	(1,100)	898	202		
Cash provided by (used in) financing activities		700	348		1,048
Net increase (decrease) in cash and cash equivalents		307	(13)		294
Cash and cash equivalents, beginning of period		294	13		307
Cash and cash equivalents, end of period	$	$ 601	$	$	$ 601

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

SIX MONTHS ENDED JUNE 30, 2009

($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 1,854	$ 144	$	$ 1,998
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(2,825)	7		(2,818)
Proceeds from divestitures of natural gas and oil properties		228			228
Additions to other property and equipment		(793)	(187)		(980)
Other investing activities		97	8		105
Cash used in investing activities		(3,293)	(172)		(3,465)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		2,825	538		3,363
Payments on credit facilities borrowings		(3,466)	(700)		(4,166)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Other financing activities	(102)	(169)			(271)
Intercompany advances, net	(1,244)	1,054	190		
Cash provided by (used in) financing activities		244	28		272
Net increase (decrease) in cash and cash equivalents		(1,195)			(1,195)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 554	$	$	$ 554

13. 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 2010, the FASB amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance in the Current Period.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance in the Current Period. Adoption had no impact on our financial position or results of operations. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective beginning on January 1, 2011, and we do not expect the implementation to have a material impact on our financial position or results of operations. See Note 11 for discussion regarding fair value measurements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Subsequent Events

On July 22, 2010, we redeemed, for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount outstanding of our 6.375% Senior Notes due 2015. In connection with the transaction, we will record a $19 million loss on redemption of debt in the third quarter of 2010.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we formed with GIP, our midstream joint venture partner (see Note 9), to own, operate, develop and acquire midstream assets, completed an initial public offering of 24,437,500 common units representing limited partner interests. In connection with the closing of the offering, Chesapeake and GIP contributed the interests of the midstream joint venture s operating subsidiary to CHKM, and CHKM will continue the business that had been conducted by the joint venture. Common units owned by public security holders represent 17.7% of all outstanding limited partner interests, and Chesapeake and GIP hold 42.3% and 40%, respectively, of all outstanding limited partner interests. The limited partners, collectively, have a 98% interest in CHKM and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2% interest in CHKM.

Certain terms of our midstream credit facility have been amended as of August 2, 2010. The total borrowing capacity has been increased to $300 million with an option to upsize to $375 million. In addition, the maturity date has been extended to July 31, 2015. Borrowings under the amended midstream credit facility will bear interest at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which will be subject to a margin that varies from 1.75% to 2.25% per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 2.75% to 3.25% per annum according to the most recent indebtedness to EBITDA ratio (as defined). The amended midstream credit facility agreement also provides that, during a drop down period (as defined), the maximum permitted indebtedness-to-EBITDA maintenance ratio (as defined) will increase to 4.00 to 1 (was 3.50 to 1).

On August 3, 2010, we filed a shelf registration statement on Form S-3 with the SEC for the offering from time to time of debt securities.

On August 3, 2010, we commenced tender offers to purchase for cash any and all of our outstanding 7.00% Senior Notes due 2014, 6.625% Senior Notes due 2016 and 6.25% Senior Notes due 2018. In conjunction with each tender offer, we are soliciting from holders of these notes consents to certain proposed amendments to each of the indentures governing the notes to, among other things, eliminate substantially all of the restrictive covenants, certain events of default and other related provisions. Each tender offer and consent solicitation will expire on August 30, 2010, unless extended.

We intend to fund the purchase of the notes tendered pursuant to the tender offers with, and the tender offers are conditioned upon our receipt of, the proceeds of a contemplated public offering of one or more series of new senior notes and from cash on hand. Following the payment for notes validly tendered pursuant to the terms of the tender offers, we currently anticipate that we will, but we are not obligated to, call for redemption any of the notes that remain outstanding following consummation of the tender offers. Upon completion of the tender offers and redemptions, we will have repaid all series of our outstanding senior notes that were issued under our indentures containing the more restrictive covenants described in Note 6.

Subsequent to June 30, 2010, we have entered into multiple purchase agreements or have signed letters of intent to acquire leasehold for approximately $750 million.

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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 six months ended June 30, 2010 (the Current Quarter and the Current Period) and the three and six months ended June 30, 2009 (the Prior Quarter and the Prior Period):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net Production:				
Natural gas (bcf)	227.2	204.3	436.8	400.0
Oil (mmbbl)	4.4	3.2	8.3	6.0
Natural gas equivalent (bcfe)	253.8	223.2	486.6	436.2
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 733	$ 548	$ 1,676	$ 1,223
Natural gas derivatives realized gains (losses)	552	587	931	1,096
Natural gas derivatives unrealized gains (losses)	(195)	(192)	219	(123)
Total natural gas sales	1,090	943	2,826	2,196
Oil sales	251	169	493	272
Oil derivatives realized gains (losses)	21	10	41	19
Oil derivatives unrealized gains (losses)	(201)	(25)	(301)	7
Total oil sales	71	154	233	298
Total natural gas and oil sales	$ 1,161	$ 1,097	$ 3,059	$ 2,494
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 3.23	$ 2.68	$ 3.84	$ 3.06
Oil ($ per bbl)	$ 56.58	$ 53.59	$ 59.38	$ 45.19
Natural gas equivalent ($ per mcfe)	$ 3.88	$ 3.21	$ 4.46	$ 3.43
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 5.66	$ 5.56	$ 5.97	$ 5.80
Oil ($ per bbl)	$ 61.43	$ 56.72	$ 64.35	$ 48.32
Natural gas equivalent ($ per mcfe)	$ 6.14	$ 5.89	$ 6.46	$ 5.98
Other Operating Income[(a)] ($ in millions):				
Marketing, gathering and compression	$ 30	$ 32	$ 59	$ 61
Service operations	$ 5	$ (2)	$ 12	$ 3
Other Operating Income[(a)] ($ per mcfe):				
Marketing, gathering and compression	$ 0.12	$ 0.14	$ 0.12	$ 0.14
Service operations	$ 0.02	$ (0.01)	$ 0.03	$ 0.01
Expenses ($ per mcfe):				
Production expenses	$ 0.84	$ 0.95	$ 0.86	$ 1.03
Production taxes	$ 0.15	$ 0.11	$ 0.18	$ 0.11
General and administrative expenses	$ 0.41	$ 0.33	$ 0.44	$ 0.38
Natural gas and oil depreciation, depletion and amortization	$ 1.34	$ 1.32	$ 1.33	$ 1.70
Depreciation and amortization of other assets	$ 0.21	$ 0.26	$ 0.21	$ 0.26
Interest expense[(b)]	$ 0.13	$ 0.29	$ 0.18	$ 0.22
Interest Expense ($ in millions):				
Interest expense	$ 35	$ 69	$ 90	$ 107
Interest rate derivatives realized (gains) losses	(2)	(5)	(4)	(12)
Interest rate derivatives unrealized (gains) losses	(49)	(42)	(77)	(87)

Total interest expense	$	(16)	$	22	$	9	$	8
Net Wells Drilled		270		212		513		476
Net Producing Wells as of the End of the Period		22,216		22,626		22,216		22,626

(a) Includes revenue and operating costs and excludes depreciation and amortization of other assets.

(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.

We are one of the largest producers of natural gas in the United States. We own interests in approximately 44,400 producing natural gas and oil wells that are currently producing approximately 2.9 bcfe per day, 89% of which is natural gas. Our strategy is focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S., primarily in our Big 6 shale plays: the Barnett Shale in the Fort Worth Basin of north-central Texas, the Haynesville and Bossier Shales in the Ark-La-Tex area of northwestern Louisiana and East Texas, the Fayetteville Shale in the Arkoma Basin of central Arkansas, the Marcellus Shale in the northern Appalachian Basin of West Virginia, Pennsylvania and New York and the Eagle Ford Shale in South Texas. We also have substantial operations in the Granite Wash Plays of western Oklahoma and the Texas Panhandle regions as well as various other plays, both conventional and unconventional, in the Mid-Continent, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and Ark-La-Tex regions of the United States. We have vertically integrated our operations and own substantial midstream, compression, drilling and oilfield service assets.

We announced earlier this year that we are extending our strategy to apply the horizontal drilling expertise we have gained in our natural gas plays to unconventional oil reservoirs. Our goal is to reach a balanced mix of natural gas and liquids revenue as quickly as possible through organic drilling, rather than through acquisitions. This transition is already apparent in the mix of natural gas and oil and natural gas liquids wells we are drilling. In 2010, we expect that approximately 32% of our drilling and completion capital expenditures will be allocated to liquids-rich plays, compared to 10% in 2009, and we are projecting that these expenditures will reach 55% in 2012. Our production of oil and natural gas liquids has been increasing in 2010 as we develop our new unconventional oil plays, particularly in the Granite Wash and Eagle Ford Shale. To date, the company has built leasehold positions and established production in 12 disclosed and other undisclosed liquids-rich plays. The company now owns approximately 2.4 million net leasehold acres in liquids-rich plays.

Chesapeake began 2010 with estimated proved reserves of 14.254 tcfe and ended the Current Period with 15.459 tcfe, an increase of 1.205 tcfe, or 8.5%. During the Current Period, we replaced 487 bcfe of production with an internally estimated 1.692 tcfe of new proved reserves, for a reserve replacement rate of 348%. The Current Period s proved reserve movement included 2.226 tcfe of extensions, 428 bcfe of positive performance revisions and 121 bcfe of positive revisions resulting from an increase in the twelve-month trailing average natural gas and oil prices between December 31, 2009 and June 30, 2010. During the Current Period, we acquired 35 bcfe of estimated proved reserves and divested 1.118 tcfe of estimated proved reserves.

During the Current Period, Chesapeake continued the industry s most active drilling program, drilling 687 gross operated wells (440 net wells with an average working interest of 64%) and participating in another 562 gross wells operated by other companies (73 net wells with an average working interest of 13%). The company s drilling success rate was 99% for both company-operated wells and for non-operated wells. Also during the Current Period, we invested $2.003 billion in operated wells (using an average of 122 operated rigs) and $303 million in non-operated wells (using an average of 108 non-operated rigs) for total drilling, completing and equipping costs of $2.306 billion (net of carries).

Our total Current Quarter production was 253.8 bcfe, comprised of 227.2 bcf of natural gas (90% on a natural gas equivalent basis) and 4.4 mmbbls of oil and natural gas liquids (10% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 2.789 bcfe, an increase of 336 mmcfe, or 14%, over the 2.453 bcfe produced per day in the Prior Quarter.

Our total Current Period production was 486.6 bcfe, comprised of 436.8 bcf of natural gas (90% on a natural gas equivalent basis) and 8.3 mmbbls of oil and natural gas liquids (10% on a natural gas equivalent basis). Daily production for the Current Period averaged 2.688 bcfe, an increase of 278 mmcfe, or 12%, over the 2.410 bcfe produced per day in the Prior Period.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.9 million net acres) and 3-D seismic (25.5 million acres) in the U.S. and the largest inventory of U.S. natural gas shale play leasehold (2.8 million net acres) and now owns the largest inventory of leasehold in two of the Top 3 new unconventional liquids-rich plays the Eagle Ford Shale and the Niobrara Shale. We are currently using 133 operated drilling rigs to further develop our inventory of approximately 40,000 net drillsites. Based on the level of drilling activity we have planned, we anticipate reporting full-year production growth of approximately 13% in 2010 and 18% in 2011.

Business Strategy

Strategic and Financial Plan

On May 10, 2010, we announced a strategic and financial plan designed to increase shareholder value, reduce long-term debt and ultimately achieve an investment grade rating for our debt securities. Since then, we have implemented multiple parts of the plan as noted below.

Debt Reduction. During the Current Quarter, we issued in private placements 2.6 million shares of two series of our 5.75% Cumulative Non-Voting Convertible Preferred Stock resulting in net proceeds to us of approximately $2.562 billion. We used the net proceeds of these preferred stock offerings to redeem in whole approximately $1.934 billion in principal amount (approximately $1.985 billion in redemption price, plus accrued interest) of four series of our outstanding senior notes and to repay $577 million in borrowings outstanding under our corporate revolving bank credit facility. Additionally, we recently commenced tender offers and consent solicitations for $1.5 billion aggregate principal amount of three additional series of senior notes. We plan to fund the purchase of the notes tendered pursuant to the tender offers with, and the tender offers are conditioned upon our receipt of, the proceeds of a contemplated public offering of one or more series of new senior notes. We plan to redeem any of the notes subject to the tender offers that are not tendered. Upon completion of the tender offers and redemptions, we will have repaid all series of our outstanding senior notes that were issued under our more restrictive indentures. We also anticipate seeking to repay up to an additional $1.7 billion of long-term debt by the second quarter of 2012 using proceeds from various asset monetizations. The company remains committed to achieving investment grade credit metrics by no later than year-end 2012.

Increased Focus on Liquids. In recognition of the significant and persistent value gap that has developed between natural gas and oil prices, Chesapeake has accelerated its transition to a more liquids-rich asset base. We have redirected a significant portion of our technological, geoscientific, leasehold acquisition and drilling expertise to identifying, securing and commercializing unconventional liquids-rich plays. This planned transition will result in a more balanced portfolio between natural gas and liquids and by year-end 2015, we expect to increase our liquids production to approximately 200,000 bbls per day, or approximately 25% of total production (using a 6:1 natural gas to liquids ratio), through organic growth and expect revenue from liquids to be approximately 40% of total production revenue.

During the Current Period, we invested heavily in new leasehold acquisitions in various liquids-rich plays, including the Anadarko Basin s Granite Wash, Cleveland, Tonkawa and Mississippian plays; the Permian Basin s Wolfcamp, Bone Spring, Avalon and Wolfberry plays; the Eagle Ford Shale in South Texas; the Niobrara Shale in the Powder River and DJ Basins; the Frontier Sand in the Powder River Basin; and various other new plays the company is not yet ready to discuss. After this aggressive effort to capture leasehold in a large number of highly competitive liquids-rich unconventional plays, we expect to become a significant seller of leasehold through planned joint venture transactions.

Planned Asset Monetizations. During the 2010 second half and throughout 2011, the company will focus on recapturing a significant portion of new leasehold expenditures through joint ventures in several of our new liquids-rich plays. The first of these is expected to be a joint venture in the Eagle Ford Shale, where the company currently has approximately 550,000 net acres. The company anticipates an Eagle Ford transaction will be announced in the 2010 third quarter. Other anticipated significant asset monetizations during the second half of 2010 and the first half of 2011 include a volumetric production payment (VPP), the sale of a minority equity interest in a Marcellus Shale subsidiary, a midstream asset sale and various other smaller planned monetizations. In total, Chesapeake is targeting to receive proceeds of approximately $3.0 - 3.5 billion in the 2010 second half and approximately $2.5 - 3.0 billion in 2011 from asset monetizations, which will enable the company to further reduce its debt and accelerate drilling on its unconventional liquids-rich plays.

Each of the foregoing proposed sales, joint ventures and other transactions is subject to changes in market conditions and other factors, and there can be no assurance that we will complete any or all of these transactions on a timely basis or at all.

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Implementing the Plan. Chesapeake plans to implement its strategic and financial plan by:

Reducing drilling of natural gas wells except for those required to hold leasehold by production or to use a drilling carry provided by a joint venture partner until such time as natural gas prices rise above $6.00 per mcf;

Leasing and developing substantial new liquids-rich plays in which the company can acquire very large leasehold positions of 250,000 - 750,000 net acres;

Within one year of acquisition, selling a minority interest in a new play to recover all or virtually all of the cost to acquire the leasehold in the play and to fund a significant portion of Chesapeake s future drilling costs in the play;

Accelerating drilling of liquids-rich plays until year-end 2012 when the company s drilling capital expenditures are balanced approximately 45/55 between natural gas plays and liquids-rich plays;

Continuing to add proved reserves, net of monetizations and divestitures, of approximately 2.5 - 3.0 tcfe (415 - 500 million boe) annually; and

Accomplishing these goals without the issuance of additional equity and with an overall reduction of debt levels such that the company becomes investment grade by year-end 2012.

Budgeted Capital Expenditures

Our exploration, development and acquisition activities require us to make substantial capital expenditures. Our current budgeted drilling and completion capital expenditures, net of drilling carries, are $4.5 - $4.6 billion in both 2010 and 2011. While we believe that our anticipated internally generated cash flow, asset monetizations, cash resources and other sources of liquidity will allow us to fully fund our 2010 operating and capital expenditure requirements, decreases in natural gas and oil prices and various other factors could require us to curtail our spending.

With our increased focus on the company s liquids-rich plays, we have revised our 2010 and 2011 drilling plans to redirect capital from our natural gas plays to our liquids-rich plays. We have reduced our projected 2011 natural gas drilling and completion capital expenditures by approximately $400 million and increased our projected liquids-rich drilling and completion capital expenditures by approximately $400 million compared to 2010. We plan to redirect this capital to accelerate drilling activity in our increasingly promising liquids-rich plays, particularly in the Granite Wash, Eagle Ford Shale, Anadarko Basin, Permian Basin and Rocky Mountain unconventional plays. Of Chesapeake s 133 current operated rigs, 91 are drilling wells primarily focused on unconventional natural gas plays and 42 are drilling wells primarily focused on liquids-rich plays.

2010 Asset Monetizations

In January 2010, Chesapeake completed its fourth joint venture in its Big 6 shale plays. In this joint venture transaction in the Barnett Shale, Total E&P USA, Inc., a wholly owned subsidiary of Total S.A., paid $800 million in cash at closing and agreed to pay an additional $1.45 billion in drilling carries. The following table provides information about our remaining joint venture drilling carries as of June 30, 2010 ($ in millions):

Shale Play	Joint Venture Partner	Joint Venture Date	Drilling Carries Remaining

Marcellus	Statoil	November 2008	$ 1,727
Barnett	Total E&P USA, Inc.	January 2010	1,151
			$ 2,878

The drilling carries in these joint ventures create a significant cost advantage for us that will allow us to continue to lower finding costs. During the Current Period and Prior Period, we had the benefit of approximately $534 million and $580 million, respectively, of joint venture drilling carries. Our exploration and development costs for the remainder of 2010 and in 2011 and 2012 will continue to be partially offset by the use of the balance of the drilling carries associated with our joint ventures in the Barnett and Marcellus Shales.

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In September 2009, we formed a joint venture with Global Infrastructure Partners (GIP), a New York-based private equity fund, to own and operate natural gas midstream assets. As part of the transaction, we contributed certain natural gas gathering and processing assets into a new entity, Chesapeake Midstream Partners, L.L.C. (CMP), and GIP purchased a 50% interest in CMP for $588 million in cash. In May 2010, we received a $75 million cash distribution from CMP.

The joint ventures in our shale plays and our midstream joint venture with GIP are a complementary part of our business strategy to maximize the value of our leasehold inventory and related assets and minimize our investment risk.

In February 2010, the company completed its sixth VPP for proceeds of $180 million, or $3.95 per mcfe. In June 2010, we completed our seventh VPP for proceeds of $335 million, or $8.73 per mcfe. In the Current Quarter, we sold producing properties and gathering systems in Virginia and in the Permian Basin for proceeds of approximately $330 million. During the Current Period, as part of our joint venture arrangements with Statoil and Plains Exploration & Production Company, we sold an interest in additional leasehold in the Marcellus and Haynesville Shale plays for approximately $320 million.

Initial Public Offering of Chesapeake Midstream Partners, L.P.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we formed with GIP to own, operate, develop and acquire midstream assets, completed an initial public offering of 24,437,500 common units representing limited partner interests. In connection with the closing of the offering, Chesapeake and GIP contributed interests of their joint venture s operating subsidiary to CHKM, and CHKM will continue the business that had been conducted by the joint venture. Common units owned by public security holders represent 17.7% of all outstanding limited partner interests, and Chesapeake and GIP hold 42.3% and 40.0%, respectively, of all outstanding limited partner interests. The limited partners, collectively, have a 98% interest in CHKM and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2% interest in CHKM. CHKM is currently projecting distributions to Chesapeake in respect of its limited partner and general partner interests will be approximately $20 million quarterly. In the future, we may enter into dropdown transactions with CHKM for some of the assets owned by our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P. (CMD). CMD primarily owns gas gathering operations in the Haynesville, Fayetteville, Marcellus and Eagle Ford Shales.

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 $2.978 billion in the Current Period compared to $1.998 billion in the Prior Period. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding non-cash items such as impairments of assets, 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. To mitigate the risk of declines in natural gas and oil prices and to provide more predictable future cash flow from operations, we currently have hedged through swaps and collars 51% of our expected remaining natural gas and oil production in 2010 at average prices of $8.32 per mcfe. Our natural gas and oil hedges as of June 30, 2010 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.

Our $3.5 billion corporate revolving bank credit facility, our $300 million midstream revolving bank credit facility and cash and cash equivalents are other sources of liquidity. At August 5, 2010, there was $1.051 billion of borrowing capacity available under the corporate credit facility and $90.6 million of borrowing capacity under the midstream credit facility. We use the facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $7.044 billion and repaid $7.415 billion in the Current Period, and we borrowed $3.363 billion and repaid $4.166 billion in the Prior Period from our revolving credit facilities. A substantial portion of our natural gas and oil properties is currently unencumbered and therefore available to be pledged as additional collateral under our corporate revolving bank credit facility if needed based on our periodic borrowing base and collateral redeterminations. Accordingly, we believe our borrowing capacity under this facility will not be reduced as a result of any such future periodic redeterminations. Our midstream facility is secured by substantially all of our wholly owned midstream assets and is not subject to periodic borrowing base redeterminations.

On May 17, 2010, we issued 600,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock, par value $0.01 per share and liquidation preference $1,000 per share, in a private placement for net proceeds of approximately $594 million. We issued an additional 900,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock on June 18, 2010, upon the exercise of the purchasers option to place the additional shares, for net proceeds of approximately $877 million.

On May 17, 2010, we issued 1,100,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock (Series A), par value $0.01 per share and liquidation preference $1,000 per share, in a private placement for net proceeds of approximately $1.091 billion.

In the Current Period and Prior Period, we received $271 million and $9 million, respectively, for settlements of derivatives which were classified as cash flows from financing activities.

In the Current Period, we received a $75 million cash distribution from our midstream joint venture which was accounted for as a return on investment and reflected as cash flows from operating activities.

On February 2, 2009, we completed a public offering of $1.0 billion aggregate principal amount of senior notes due 2015, which have a stated coupon rate of 9.5% per annum. The senior notes were priced at 95.071% of par to yield 10.625%. On February 17, 2009, we completed an offering of an additional $425 million aggregate principal amount of the 9.5% Senior Notes due 2015. The additional senior notes were priced at 97.75% of par plus accrued interest from February 2 to February 17, 2009 to yield 10.0% per annum. Net proceeds of $1.346 billion from these two offerings were used to repay outstanding indebtedness under our corporate revolving bank credit facility, which we reborrow from time to time to fund drilling and leasehold acquisition initiatives and for general corporate purposes.

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 and our other 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, changes in 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 $95 million and $89 million in the Current Period and the Prior Period, respectively. We paid dividends on our preferred stock of $11 million in the Current Period and $12 million in the Prior Period.

On June 21, 2010, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Current Quarter.

On June 21, 2010, we called for redemption in whole for a redemption price of approximately $619 million, plus accrued interest, $600 million in principal amount of our 6.375% Senior Notes due 2015. This redemption occurred on July 22, 2010.

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Credit Risk

A significant portion of our credit risk is concentrated in derivative instruments that 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 we attempt to limit our exposure to non-performance by any single counterparty. During the more than 15 years we have engaged in hedging activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. On June 30, 2010, our commodity and interest rate derivative instruments were spread among 14 counterparties. Our multi-counterparty secured hedging facility includes 13 of our counterparties which are required to secure their natural gas and oil hedging obligations in excess of defined thresholds. We now use this facility for all of our commodity hedging.

Our accounts receivable are primarily from purchasers of natural gas and oil ($685 million at June 30, 2010) and exploration and production companies which own interests in properties we operate ($558 million at June 30, 2010). 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 parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized $0, $5 million, $0 and $13 million, respectively, of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities increased to $3.732 billion during the Current Period, compared to $3.465 billion during the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Acquisitions of natural gas and oil proved properties	$ 76	$ 2
Acquisition of leasehold and unproved properties	2,452	410
Exploration and development of natural gas and oil properties	2,235	1,995
Geological and geophysical costs[(a)]	97	113
Interest capitalized on unproved properties	326	298
Proceeds from sales of volumetric production payments	(502)	(41)
Proceeds from divestitures of proved and unproved properties	(1,431)	(187)
Deposits for acquisitions	17	9
Deposits for divestitures		(8)
Total natural gas and oil investing activities	3,270	2,591
Other Investing Activities:		
Additions to other property and equipment	679	980
Additions to investments	109	(2)
Proceeds from sales of other assets	(306)	(104)
Other	(20)	
Total other investing activities	462	874
Total cash used in investing activities	$ 3,732	$ 3,465

(a) Including related capitalized interest.

In connection with a reduced budget for acquisitions, we used 15,823,838 shares of our common stock to acquire leasehold and mineral interests in the Prior Period, pursuant to an acquisition shelf registration statement.

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Bank Credit Facilities

We utilize two bank credit facilities, described below, as sources of liquidity.

	Corporate Credit Facility[a]	Midstream Credit Facility[b]
	($ in millions)	
Borrowing capacity	$ 3,500	$ 250
Maturity date	November 2012	September 2012
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of June 30, 2010	$ 1,371	$ 150
Letters of credit outstanding as of June 30, 2010	$ 14	$

(a) Borrowers are Chesapeake Exploration, L.L.C. and Chesapeake Appalachia, L.L.C.

(b) Borrower is Chesapeake Midstream Operating, L.L.C., a wholly owned subsidiary of Chesapeake Midstream Development, L.P. Certain terms of the credit agreement for this facility were amended August 2, 2010. See Note 14 of the notes to our condensed consolidated financial statements.

Our credit facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates under our corporate credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, none of our credit 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.

Corporate Credit Facility

Our $3.5 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by natural gas and oil proved reserves and bear interest at our option at either (i) the greater of the reference rate of Union Bank, N.A., or the federal funds effective rate plus 0.50%, both of which are subject to a margin that varies from 0.00% to 0.75% per annum according to our senior unsecured long-term debt ratings, or (ii) the London Interbank Offered Rate (LIBOR), plus a margin that varies from 1.50% to 2.25% 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 of 0.50%. 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. It was amended during the Current Quarter to, among other things, bring in additional lenders to replace Lehman Brothers unfunded commitment. The credit facility agreement requires us to maintain an indebtedness (excluding discount on senior notes) 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 0.35 to 1 and our indebtedness to EBITDA ratio was 2.64 to 1 at June 30, 2010. 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 Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $75 million.

The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned restricted subsidiaries.

Midstream Credit Facility

Our $250 million midstream syndicated revolving bank credit facility is used to fund capital expenditures to build natural gas gathering and other systems for our drilling program and for general corporate purposes associated with our midstream operations. On August 2, 2010, the total commitment was increased to $300 million with an option to increase to $375 million. Borrowings under the midstream credit facility are secured by all of the assets of the wholly owned subsidiaries (the restricted subsidiaries) of Chesapeake Midstream Development, L.P. (CMD), itself a wholly owned subsidiary of Chesapeake, and bear interest at our option at either (i) the greater of the reference rate of Wells Fargo Bank, National Association, the federal funds effective rate plus 0.50%, and the one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 2.00% to 2.75% (as amended, 1.75% to 2.25%) per annum according to the most recent indebtedness to EBITDA ratio (as defined) or (ii) the LIBOR plus a margin that varies from 3.00% to 3.75% (as amended, 2.75% to 3.25%) per annum according to the most recent indebtedness to EBITDA ratio (as defined). The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent indebtedness to EBITDA ratio (as defined). Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The midstream credit facility agreement contains various covenants and restrictive provisions which limit the ability of CMD and its restricted 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 3.00 to 1. As defined by the credit facility agreement, our indebtedness to EBITDA ratio was 1.03 to 1 and our EBITDA to interest expense coverage ratio was 19.77 to 1 at June 30, 2010. The amended midstream credit facility agreement provides that, during a drop down period (as defined), the maximum permitted indebtedness-to-EBITDA maintenance ratio will increase to 4.00 to 1. If CMD or its restricted 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 facility could be declared immediately due and payable. The midstream credit facility agreement also has cross default provisions that apply to other indebtedness of CMD and its restricted subsidiaries may have with an outstanding principal amount in excess of $15 million.

Hedging Facility

We have a multi-counterparty hedge facility with 13 counterparties that have committed to provide approximately 5.6 tcfe of trading capacity and an aggregate mark-to-market capacity of $15.0 billion under the terms of the facility. As of June 30, 2010, we had hedged a total of 2.1 tcfe under the facility. The multi-counterparty facility allows us to enter into cash-settled natural gas and oil price and basis hedges with the counterparties. Our obligations under the multi-counterparty facility are secured by natural gas and oil proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times, and guarantees by our subsidiaries that also guarantee our corporate revolving bank credit facility and indentures. The counterparties obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts they owe to Chesapeake exceed defined thresholds. The maximum volume-based trading capacity under the facility is governed by the expected production of the pledged reserve collateral, and volume-based trading limits are applied separately to price and basis hedges. In addition, there are volume-based sub-limits for natural gas and oil hedges. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain collateral coverage and other requirements are met. The facility does not have a maturity date. Counterparties to the agreement have the right to cease trading with the company on a prospective basis as long as obligations associated with any existing trades in the facility continue to be satisfied in accordance with the terms of the agreement.

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Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of June 30, 2010, senior notes represented approximately $9.0 billion of our total debt and consisted of the following ($ in millions):

7.625% senior notes due 2013	$	500
7.0% senior notes due 2014[(a)]		300
6.375% senior notes due 2015[(b)]		600
9.5% senior notes due 2015		1,425
6.625% senior notes due 2016[(a)]		600
6.25% euro-denominated senior notes due 2017[(c)]		738
6.5% senior notes due 2017		1,100
6.25% senior notes due 2018[(a)]		600
7.25% senior notes due 2018		800
6.875% senior notes due 2020		500
2.75% contingent convertible senior notes due 2035[(d)]		451
2.5% contingent convertible senior notes due 2037[(d)]		1,378
2.25% contingent convertible senior notes due 2038[(d)]		752
Discount on senior notes[(e)]		(832)
Interest rate derivatives[(f)]		68
	$	8,980

(a) Subsequent to June 30, 2010, we commenced a tender offer for these notes. See Note 14 of our condensed consolidated financial statements included in this report for information on subsequent events.

(b) These notes were called for redemption on June 21, 2010 and redeemed on July 22, 2010 utilizing funds from our corporate revolving credit facility.

(c) The principal amount shown is based on the dollar/euro exchange rate of $1.2291 to 1.00 as of June 30, 2010. See Note 2 of our condensed consolidated financial statements included in this report for information on our related foreign currency derivatives.

(d) 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 when 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 second quarter of 2010, 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 third quarter of 2010 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	$	48.71	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$	64.26	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$	107.36	June 14, 2019

(e) Included in this discount is $751 million at June 30, 2010 associated with the equity component of our contingent convertible senior notes.

(f) See Note 2 of our condensed consolidated financial statements included in this report for discussion related to these instruments.

As of June 30, 2010 and currently, debt ratings for the senior notes are Ba3 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings (stable outlook).

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. Our senior note obligations are guaranteed by certain of our wholly owned subsidiaries. See Note 12 of the financial statements included in this report for condensed consolidating financial information regarding our guarantor and non-guarantor subsidiaries. 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. Upon completion of the pending tender offers and consent solicitations of three series of senior notes (see footnote (a) to the senior note table above) and, if applicable, the redemption of any notes that remain outstanding, we will have repaid all series of our outstanding senior notes that were issued under our indentures containing these restrictive covenants. 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. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our revolving bank credit facilities. As of June 30, 2010, we estimate that secured commercial bank indebtedness of approximately $4.8 billion could have been incurred under the most restrictive indenture covenant.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at June 30, 2010. These include commitments related to drilling rig and compressor leases, transportation and drilling contracts, natural gas and oil purchase obligations, minimum volume commitments, net acreage maintenance commitments, and other commitments. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in this report.

Results of Operations Three Months Ended June 30, 2010 vs. June 30, 2009

General. For the Current Quarter, Chesapeake had net income of $255 million, or $0.37 per diluted common share, on total revenues of $2.012 billion. This compares to net income of $243 million, or $0.39 per diluted common share, on total revenues of $1.673 billion during the Prior Quarter.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.161 billion compared to $1.097 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 253.8 bcfe at a weighted average price of $6.14 per mcfe, compared to 223.2 bcfe produced in the Prior Quarter at a weighted average price of $5.89 per mcfe (weighted average prices exclude the effect of unrealized losses on natural gas and oil derivatives of $396 million and $217 million in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $63 million and increased production resulted in a $180 million increase, for a total increase in revenues of $243 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 generated by our successful drilling results.

For the Current Quarter, we realized an average price per mcf of natural gas of $5.66, compared to $5.56 in the Prior Quarter (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $61.43 and $56.72 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $573 million, or $2.26 per mcfe, in the Current Quarter and a net increase of $597 million, or $2.68 per mcfe, in the Prior Quarter.

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Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $25 million and $24 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $4 million, without considering the effect of derivative activities.

The following tables show our production and price received by region for the Current Quarter and the Prior Quarter:

	Three Months Ended June 30, 2010						
	Natural Gas		Oil		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Barnett Shale	47.4	$ 1.91	0.2	$ 29.05	48.7	19%	$ 1.99
Fayetteville Shale	33.7	$ 3.08		$	33.7	13	$ 3.08
Haynesville Shale	51.0	$ 3.37		$	51.0	20	$ 3.37
Marcellus Shale	11.1	$ 4.03		$	11.1	5	$ 4.03
Bossier Shale		$		$			$
Eagle Ford Shale	0.2	$ 6.03	0.1	$ 69.70	0.7		$ 9.96
Other:							
Mid-Continent	58.2	$ 4.02	3.3	$ 53.86	78.1	31	$ 5.28
Permian and Delaware Basins	11.7	$ 3.70	0.6	$ 74.29	15.9	6	$ 6.00
South Texas/Gulf Coast/ Ark-La-Tex	7.3	$ 3.60	0.1	$ 73.31	7.8	3	$ 4.07
Appalachian Basin	6.6	$ 2.68	0.1	$ 61.22	6.8	3	$ 2.93
Total[b]	227.2	$ 3.23	4.4	$ 56.58	253.8	100%	$ 3.88

	Three Months Ended June 30, 2009						
	Natural Gas		Oil		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Barnett Shale	59.1	$ 1.66		$	59.1	27%	$ 1.66
Fayetteville Shale	20.4	$ 2.68		$	20.4	9	$ 2.68
Haynesville Shale	16.1	$ 3.03		$	16.1	7	$ 3.03
Marcellus Shale	6.4	$ 4.21		$	6.4	3	$ 4.21
Bossier Shale		$		$			$
Eagle Ford Shale		$		$			$
Other:							
Mid-Continent	64.3	$ 3.22	2.1	$ 52.99	76.7	34	$ 4.12
Permian and Delaware Basins	14.5	$ 2.98	0.8	$ 55.06	19.4	9	$ 4.51
South Texas/Gulf Coast/ Ark-La-Tex	18.6	$ 3.14	0.2	$ 54.68	19.8	9	$ 3.48
Appalachian Basin	4.9	$ 2.19	0.1	$ 57.37	5.3	2	$ 2.64
Total	204.3	$ 2.68	3.2	$ 53.59	223.2	100%	$ 3.21

(a) The average sales price excludes gains (losses) on derivatives.

(b) Current Quarter production reflects the sale of a 25% joint venture interest in the company s Barnett Shale assets on January 25, 2010 (15.8 bcfe), the company s sixth volumetric production payment transaction on February 5, 2010 (2.0 bcfe), the company s seventh volumetric production payment transaction on June 14, 2010 (0.5 bcfe) and the sale of producing properties in Virginia and in the Permian Basin in the Current Quarter (1.8 bcfe).

Natural gas production represented approximately 90% and 92% of our total production volume on a natural gas equivalent basis in the Current Quarter and the Prior Quarter, respectively.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $793 million in marketing, gathering and compression sales in the Current Quarter, with corresponding marketing, gathering and compression expenses of $763 million, for a net margin before depreciation of $30 million. This compares to sales of $532 million, expenses of $500 million and a net margin before depreciation of $32 million in the Prior Quarter. In the Current Quarter, Chesapeake realized

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an increase in marketing, gathering and compression sales and operating expenses primarily due to an increase in third-party marketing, gathering and compression volumes. This increase was offset by a decrease in revenues, expenses and margin related to certain of our midstream businesses that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $58 million in service operations revenue in the Current Quarter with corresponding service operations expense of $53 million, for a net margin before depreciation of $5 million. This compares to revenue of $44 million, expenses of $46 million and a net margin before depreciation of ($2) million in the Prior Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $213 million in both the Current Quarter and the Prior Quarter. On a unit-of-production basis, production expenses were $0.84 per mcfe in the Current Quarter compared to $0.95 per mcfe in the Prior Quarter. The decrease in the Current Quarter was primarily the result of completing new high volume wells with lower per unit production expenses.

Production Taxes. Production taxes were $37 million in the Current Quarter compared to $24 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.15 per mcfe in the Current Quarter compared to $0.11 per mcfe in the Prior Quarter. The $13 million increase in production taxes in the Current Quarter is due to an increase in the average realized sales price of natural gas and oil of $0.67 per mcfe (excluding gains or losses on derivatives) and an increase in production of 31 bcfe. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher.

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 $106 million in the Current Quarter and $74 million in the Prior Quarter. General and administrative expenses were $0.41 and $0.33 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of the company s continued growth as well as increased spending on advertising and related costs associated with our efforts to educate the public concerning the benefits of natural gas.

Included in general and administrative expenses is stock-based compensation of $21 million for the Current Quarter and $19 million for the Prior Quarter. 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 of our condensed consolidated 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 exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $87 million and $89 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 $340 million and $295 million during the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.34 and $1.32 in the Current Quarter and in the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $53 million in the Current Quarter and $58 million in the Prior Quarter. Depreciation and amortization of other assets was $0.21 and $0.26 per mcfe for the Current Quarter and the Prior Quarter, respectively. The decrease in the Current Quarter is primarily due to certain of our midstream businesses that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010 offset by additional depreciation expense associated with assets acquired over the past year. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 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 twenty 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.

Restructuring Costs. In the Prior Quarter, we recorded $34 million of restructuring and relocating costs in our Eastern Division and certain other workforce reduction costs. We reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring include termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 10 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of these costs.

Interest (Expense) Income. Interest (expense) income decreased to $16 million in the Current Quarter compared to ($22) million in the Prior Quarter as follows:

	Three Months Ended June 30,	
	2010	**2009**
	($ in millions)	
Interest expense on senior notes	$ (190)	$ (196)
Interest expense on credit facilities	(12)	(17)
Capitalized interest	179	152
Realized gain (loss) on interest rate derivatives	2	5
Unrealized gain (loss) on interest rate derivatives	49	42
Amortization of loan discount and other	(12)	(8)
Total interest (expense) income	$ 16	$ (22)
Average long-term borrowings on senior notes	$ 10,806	$ 11,493

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.13 per mcfe in the Current Quarter compared to $0.29 in the Prior Quarter. The decrease in interest expense per mcfe is primarily due to increased production and an increase in capitalized interest. Capitalized interest increased $27 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.

Impairment of Investments. In the Prior Quarter, we paid $10 million to fund various costs associated with the operations of an investee, Ventura Refining and Transmission LLC. These costs were expensed as incurred.

Loss on Redemptions or Exchanges of Chesapeake Debt. During the Current Quarter, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Current Quarter consisting primarily of the redemption premium and the write-off of the related discount on senior notes and deferred charges.

In the Prior Quarter, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock valued at approximately $53 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 63% of the face value of the notes. Of the $85 million principal amount of convertible notes exchanged in the Prior Quarter, $52 million was allocated to the debt component and the remaining $33 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The

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difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss (including $1 million of deferred charges associated with the exchanges).

Other Income (Expense). Other income (expense) was $20 million and ($2) million in the Current Quarter and in the Prior Quarter, respectively. The Current Quarter consisted of $1 million of interest income, $27 million of equity in earnings related to our equity method investments and ($8) million of miscellaneous expense. The Prior Quarter consisted of $2 million of interest income, a ($7) million loss related to our equity in the net losses of certain investments and $3 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $159 million in the Current Quarter compared to $145 million in the Prior Quarter. Of the $14 million increase in income tax expense recorded in the Current Quarter, $10 million was the result of the increase in net income before income taxes and $4 million was due to an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Quarter and 37.5% 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 Six Months Ended June 30, 2010 vs. June 30, 2009

General. For the Current Period, Chesapeake had net income of $993 million, or $1.49 per diluted common share, on total revenues of $4.810 billion. This compares to a net loss of $5.498 billion, or $9.18 per diluted common share, on total revenues of $3.668 billion during the Prior Period. The Prior Period loss was due to a non-cash impairment expense of approximately $6.0 billion, net of tax, as a result of a 36% decrease in NYMEX natural gas prices from $5.71 per mcf at December 31, 2008 to $3.63 per mcf at March 31, 2009.

Natural Gas and Oil Sales. During the Current Period, natural gas and oil sales were $3.059 billion compared to $2.494 billion in the Prior Period. In the Current Period, Chesapeake produced 486.6 bcfe at a weighted average price of $6.46 per mcfe, compared to 436.2 bcfe produced in the Prior Period at a weighted average price of $5.98 per mcfe (weighted average prices exclude the effect of unrealized losses on natural gas and oil derivatives of ($82) million and ($116) million in the Current Period and the Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $229 million and increased production resulted in a $302 million increase, for a total increase in revenues of $531 million (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 by organic growth.

For the Current Period, we realized an average price per mcf of natural gas of $5.97, compared to $5.80 in the Prior Period (weighted average prices exclude the effect of unrealized gains or losses on derivatives). Oil prices realized per barrel (excluding unrealized gains or losses on derivatives) were $64.35 and $48.32 in the Current Period and Prior Period, respectively. Realized gains or losses from our natural gas and oil derivatives resulted in a net increase in natural gas and oil revenues of $972 million, or $2.00 per mcfe, in the Current Period and a net increase of $1.115 billion, or $2.55 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 flows. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $49 million and $47 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.

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The following tables show our production and price received by region for the Current Period and the Prior Period:

	Six Months Ended June 30, 2010						
	Natural Gas		Oil		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Barnett Shale	97.1	$ 2.74	0.3	$ 32.35	99.1	20%	$ 2.79
Fayetteville Shale	64.7	$ 3.51		$	64.7	13	$ 3.51
Haynesville Shale	90.9	$ 3.84		$	90.9	19	$ 3.84
Marcellus Shale	18.6	$ 4.47		$	18.6	4	$ 4.47
Bossier Shale		$		$			$
Eagle Ford Shale	0.3	$ 5.17	0.1	$ 70.29	0.9		$ 9.32
Other:							
Mid-Continent	113.7	$ 4.67	6.2	$ 56.57	150.8	31	$ 5.84
Permian and Delaware Basins	24.1	$ 4.47	1.4	$ 74.92	32.7	7	$ 6.58
South Texas/Gulf Coast/ Ark-La-Tex	15.4	$ 4.40	0.2	$ 74.72	16.4	3	$ 4.85
Appalachian Basin	12.0	$ 3.62	0.1	$ 70.07	12.5	3	$ 3.92
Total[b]	436.8	$ 3.84	8.3	$ 59.38	486.6	100%	$ 4.46

	Six Months Ended June 30, 2009						
	Natural Gas		Oil		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Barnett Shale	116.7	$ 2.15		$	116.7	27%	$ 2.15
Fayetteville Shale	38.7	$ 3.14		$	38.7	9	$ 3.14
Haynesville Shale	26.6	$ 3.46	0.1	$ 43.39	27.2	6	$ 3.53
Marcellus Shale	9.7	$ 5.08		$	9.7	2	$ 5.08
Bossier Shale		$		$			$
Eagle Ford Shale		$		$			$
Other:							
Mid-Continent	128.6	$ 3.41	3.9	$ 44.75	152.0	35	$ 4.03
Permian and Delaware Basins	29.7	$ 3.21	1.5	$ 46.05	38.8	9	$ 4.26
South Texas/Gulf Coast/ Ark-La-Tex	39.7	$ 3.66	0.4	$ 46.20	42.2	9	$ 3.90
Appalachian Basin	10.3	$ 2.86	0.1	$ 46.93	10.9	3	$ 3.13
Total	400.0	$ 3.06	6.0	$ 45.19	436.2	100%	$ 3.43

(a) The average sales price excludes gains (losses) on derivatives.

(b) Current Period production reflects the sale of a 25% joint venture interest in the company s Barnett Shale assets on January 25, 2010 (29.8 bcfe), the company s sixth volumetric production payment transaction on February 5, 2010 (3.3 bcfe), the company s seventh volumetric production payment transaction on June 14, 2010 (0.5 bcfe) and the sale of producing properties in Virginia and in the Permian Basin in the Current Quarter (1.8 bcfe).

Natural gas production represented approximately 90% and 92% of our total production volume on a natural gas equivalent basis in the Current Period and the Prior Period, respectively.

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Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression activities are substantially for third parties who are owners in Chesapeake-operated wells. Chesapeake realized $1.637 million in marketing, gathering and compression sales in the Current Period, with corresponding marketing, gathering and compression expenses of $1.578 million, for a net margin before depreciation of $59 million. This compares to sales of $1.084 billion, expenses of $1.023 billion and a net margin before depreciation of $61 million in the Prior Period. In the Current Period, Chesapeake realized an increase in marketing, gathering and compression sales and operating expenses primarily due to an increase in third-party marketing, gathering and compression volumes. This increase was offset by a decrease in revenues, expenses and margin related to certain of our midstream businesses that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. Chesapeake recognized $114 million in service operations revenue in the Current Period with corresponding service operations expense of $102 million, for a net margin before depreciation of $12 million. This compares to revenue of $90 million, expenses of $87 million and a net margin before depreciation of $3 million in the Prior Period.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $421 million in the Current Period compared to $451 million in the Prior Period. On a unit-of-production basis, production expenses were $0.86 per mcfe in the Current Period compared to $1.03 per mcfe in the Prior Period. The decrease in the Current Period was primarily the result of completing new high volume wells with lower per unit production costs.

Production Taxes. Production taxes were $85 million in the Current Period compared to $46 million in the Prior Period. On a unit-of-production basis, production taxes were $0.18 per mcfe in the Current Period compared to $0.11 per mcfe in the Prior Period. The $39 million increase in production taxes in the Current Period is primarily due to an increase in the average realized sales price of natural gas and oil of $1.03 per mcfe (excluding gains or losses on derivatives) and an increase in production of 50 bcfe. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas and oil prices are higher.

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 $215 million in the Current Period and $164 million in the Prior Period. General and administrative expenses were $0.44 and $0.38 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of the company s continued growth as well as increased spending on advertising and related costs associated with our efforts to educate the public concerning the benefits of natural gas.

Included in general and administrative expenses is stock-based compensation of $42 million for the Current Period and $39 million for the Prior Period. 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 of our condensed consolidated 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 exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $189 million and $182 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 $647 million and $742 million during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.33 and $1.70 in the Current Period and in the Prior Period, respectively. The $0.37 decrease in the average

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DD&A rate is due primarily to the reduction of our natural gas and oil full-cost pool resulting from divestitures in 2009 and 2010, the utilization of joint venture drilling carries in 2009 and 2010 and the impairment of natural gas and oil properties in 2009.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $103 million in the Current Period and $115 million in the Prior Period. Depreciation and amortization of other assets was $0.21 and $0.26 per mcfe for the Current Period and the Prior Period, respectively. The decrease in the Current Period is primarily due to certain of our midstream businesses that were contributed to our midstream joint venture on September 30, 2009 and subsequently deconsolidated on January 1, 2010 offset by additional depreciation expense associated with assets acquired over the past year. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 10 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 twenty 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.

Impairment of Natural Gas and Oil Properties and Other Assets. Due to lower commodity prices in the first quarter of 2009, we reported a non-cash impairment charge on our natural gas and oil properties of $9.6 billion in the Prior Period. We account for our natural gas and oil properties using the full-cost method of accounting, which limits the amount of costs we can capitalize and requires us to write off these costs if the carrying value of natural gas and oil assets in the evaluated portion of our full-cost pool exceeds the sum of the present value of expected future net cash flows of proved reserves, using a 10% pre-tax discount rate based on constant pricing and cost assumptions, and the present value of certain natural gas and oil hedges. Additionally in the Prior Period, we recorded an impairment of $30 million associated with certain of our other assets.

Restructuring Costs. In the Prior Period, we recorded $34 million of restructuring and relocation costs in our Eastern Division and certain other workforce reduction costs. We reorganized our Charleston, West Virginia-based Eastern Division from a regional corporate headquarters to a regional field office consistent with the business model we use elsewhere in the country. As a result, we consolidated the management of our Eastern Division land, legal, accounting, information technology, geoscience and engineering departments into our corporate offices in Oklahoma City. The costs of the restructuring include termination benefits, consolidating or closing facilities and relocating employees. The discussion of restructuring costs in Note 10 of our condensed consolidated financial statements included in Part I of this report provides additional detail on the accounting for and reporting of these costs.

Interest (Expense) Income. Interest expense increased to ($9) million in the Current Period compared to ($8) million in the Prior Period as follows:

	Six Months Ended June 30,	
	2010	2009
	($ in millions)	
Interest expense on senior notes	$ (383)	$ (378)
Interest expense on credit facilities	(24)	(29)
Capitalized interest	340	314
Realized gain (loss) on interest rate derivatives	4	12
Unrealized gain (loss) on interest rate derivatives	77	87
Amortization of loan discount and other	(23)	(14)
Total interest expense	$ (9)	$ (8)
Average long-term borrowings on senior notes	$ 10,951	$ 11,095

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.18 per mcfe in the Current Period compared to $0.22 in the Prior Period. The decrease in interest expense per mcfe is primarily due to increased production volume and an increase in capitalized interest. Capitalized interest increased $26 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.

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Impairment of Investments. In the Prior Period, we recorded a $162 million impairment of certain investments. Each of our investees has been impacted by the dramatic slowing of the worldwide economy and the freezing of the credit markets in the fourth quarter of 2008 and into 2009. The economic weakness resulted in significantly reduced natural gas and oil prices leading to a meaningful decline in the overall level of activity in the markets served by our investees. Associated with the weakness in performance of certain of the investees, as well as an evaluation of their financial condition and near-term prospects, we recognized that an other than temporary impairment had occurred on the following investments: Gastar Exploration Ltd., $70 million; Chaparral Energy, Inc., $51 million; DHS Drilling Company, $19 million; Ventura Refining and Transmission LLC, $13 million; and Mountain Drilling Company, $9 million.

Loss on Redemptions or Exchanges of Chesapeake Debt. During the Current Period, we redeemed in whole for an aggregate redemption price of approximately $1.366 billion, plus accrued interest, approximately $364 million in principal amount of our outstanding 7.50% Senior Notes due 2013, $300 million in principal amount of our 7.50% Senior Notes due 2014 and approximately $670 million in principal amount of our 6.875% Senior Notes due 2016. Associated with the redemptions, we recognized a loss of $69 million in the Current Period consisting primarily of the redemption premium and the write-off of the related discount on senior notes and deferred charges.

In the Current Period, we privately exchanged approximately $11 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 298,500 shares of our common stock valued at approximately $9 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 80% of the face value of the notes. Of the $11 million principal amount of convertible notes exchanged in the Current Period, $7 million was allocated to the debt component and the remaining $4 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss (including a nominal amount of deferred charges associated with the exchanges).

In the Prior Period, we privately exchanged approximately $85 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 2,530,650 shares of our common stock valued at approximately $53 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 63% of the face value of the notes. Of the $85 million principal amount of convertible notes exchanged in the Prior Period, $52 million was allocated to the debt component and the remaining $33 million was allocated to the equity conversion feature and was recorded as an adjustment to paid-in-capital. The difference between the debt component and value of the common stock exchanged in these transactions resulted in the $2 million loss (including $1 million of deferred charges associated with the exchanges).

Other Income. Other income was $35 million and $5 million in the Current Period and in the Prior Period, respectively. The Current Period consisted of $2 million of interest income, $39 million of equity in earnings related to our equity method investments and ($6) million of miscellaneous income. The Prior Period consisted of $5 million of interest income, an ($8) million loss related to our equity in the net losses of certain investments and $8 million of miscellaneous income.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $621 million in the Current Period, compared to an income tax benefit of $3.298 billion in the Prior Period. Of the $3.919 billion increase in income tax expense recorded in the Current Period, $3.903 billion was the result of the increase in net income before income taxes and $16 million was due to an increase in the effective tax rate. Our effective income tax rate was 38.5% in the Current Period and 37.5% 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 and income taxes 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, 2009 (2009 Form 10-K).

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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 2010, the FASB amended its guidance on subsequent events to remove the requirement for SEC filers to disclose the date through which an entity has evaluated subsequent events. The guidance was effective upon issuance. We adopted this guidance in the Current Period.

The FASB also issued new guidance requiring additional disclosures about fair value measurements, adding a new requirement to disclose transfers in and out of Levels 1 and 2 measurements and gross presentation of activity within a Level 3 roll forward. The guidance also clarified existing disclosure requirements regarding the level of disaggregation of fair value measurements and disclosures regarding inputs and valuation techniques. We adopted this guidance in the Current Period. Adoption had no impact on our financial position or results of operations. Required disclosures for the reconciliation of purchases, sales, issuance and settlements of financial instruments valued with a Level 3 method are effective beginning on January 1, 2011 and we do not expect the implementation to have a material impact on our financial position or results of operations. See Note 11 for discussion regarding fair value measurements.

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, expected natural gas and oil production and future expenses, assumptions regarding future natural gas and oil prices, planned capital expenditures, and anticipated asset acquisitions and sales, as well as statements concerning anticipated cash flow and liquidity, business strategy and other plans and objectives for future operations. Disclosures 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 2009 Form 10-K. They include:

- the volatility of natural gas and oil prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the values of our natural gas and oil properties resulting in ceiling test write-downs;
- the availability of capital on an economic basis, including planned asset monetization transactions, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and the amount and timing of development expenditures;
- potential differences in our interpretations of new reserve disclosure rules and future SEC guidance;

inability to generate profits or achieve targeted results in our development and exploratory drilling and well operations;

leasehold terms expiring before production can be established;

hedging activities resulting in lower prices realized on natural gas and oil sales and the need to secure hedging liabilities;

a reduced ability to borrow or raise additional capital as a result of lower natural gas and oil prices;

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drilling and operating risks, including potential environmental liabilities;

changes in legislation and regulation adversely affecting our industry and our business;

general economic conditions negatively impacting us and our business counterparties;

transportation capacity constraints and interruptions that could adversely affect our cash flow; 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 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. 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 our risk management objectives.

Our general strategy for attempting to mitigate exposure to adverse natural gas and oil price changes is to hedge into strengthening natural gas and oil futures markets when prices allow us to generate high cash margins and when we view prices to be in the upper range of our predicted most likely future price range. Information we consider in forming an opinion about future prices includes general economic conditions, industrial output levels and expectations, producer breakeven cost structures, liquefied natural gas import trends, natural gas and oil storage inventory levels, industry decline rates for base production and weather trends.

We use a wide range of derivative instruments to achieve our risk management objectives, including swaps, various collar arrangements and options (puts or calls). All of these are described in more detail below. We typically use swaps or collars for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable and collars are used when the downside protection from the bought put is meaningful and the cap on upside from the sold call is at a satisfactory level. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes when the strike price levels and the premiums are attractive to us. Typically, we sell call options when we would be satisfied to sell our production at the price being capped by the call strike or believe it to be more likely than not that the future natural gas or oil price will stay below the call strike price plus the premium we will receive.

We determine the volume we may potentially hedge by reviewing the company s estimated future production levels, which are derived from extensive examination of existing producing reserve estimates and estimates of likely production (risked) from new drilling. Production forecasts are updated at least monthly and adjusted if necessary to actual results and activity levels. We do not hedge more volumes than we expect to produce, and if production estimates are lowered for future periods and hedges are already executed for some volume above the new production forecasts, the hedges are reversed. The actual fixed hedge price on our derivative instruments is derived from bidding and the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our derivative instruments are net settled based on the difference between the fixed price payment and the floating-price payment, resulting in a net amount due to or from the counterparty.

Hedging positions, including swaps and collars, are adjusted in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our hedging positions continuously and if future market conditions change and prices have fallen to levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either doing a cash settlement with our counterparty, restructuring the position, or by entering into a new swap that effectively reverses the current position (a counter-swap). The factors we consider in closing or restructuring a position before the settlement date are identical to those we reviewed when deciding to enter into the original hedge position.

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In 2009, we restructured many of our trades that included knockout features as commodity prices decreased. The knockouts were typically restructured into straight swaps or collars based on strip prices at the time of the restructure. In the latter half of 2009 and in 2010, we took advantage of attractive strip prices in 2012 through 2015 and sold natural gas and oil call options to our counterparties in exchange for 2010 and 2011 natural gas swaps with strike prices above the then current market price. This effectively allowed us to sell out-year volatility through call options at terms acceptable to us in exchange for straight natural gas swaps with strike prices well in excess of the then current market price for natural gas.

As of June 30, 2010, our natural gas and oil derivative instruments were comprised of the following:

Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.

Collars: These instruments 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 put and the call strike price, no payments are due from either party.

Call options: Chesapeake sells call options in exchange for a premium from the counterparty. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess and if the market price settles below the fixed price of the call option, no payment is due from either party.

Put options: Chesapeake receives a premium from the counterparty in exchange for the sale of a put option. At the time of settlement, if the market price falls below the fixed price of the put option, Chesapeake pays the counterparty such shortfall, and if the market price settles above the fixed price of the put option, no payment is due from either party.

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.

Basis protection swaps: These instruments are arrangements that guarantee a price differential to NYMEX for natural gas from a specified delivery point. For non-Appalachian Basin 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.

In accordance with accounting guidance for derivatives and hedging, 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. Cash settlements of our derivative arrangements are generally classified as operating cash flows unless the derivative contains a significant financing element at contract inception, in which case, all cash settlements are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.

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As of June 30, 2010, we had the following open natural gas and oil derivative instruments designed to hedge a portion of our natural gas and oil production for periods after June 30, 2010:

		Weighted Average Price				Cash Flow	Net	Fair
	Volume	Fixed	Put	Call	Differential	Hedge	Premiums	Value
Natural Gas:	(bbtu)		(per mmbtu)				($ in millions)	
Swaps:								
Q3 2010	68,348	$ 7.48	$	$	$	Yes	$	$ 193
Q4 2010	69,588	7.54				Yes		177
2011	56,322	7.73				Yes		133
Other Swaps[(a)]:								
Q3 2010	50,600	7.44				No		140
Q4 2010	50,320	8.04				No		131
2011	270,110	7.59				No		376
Other Collars:								
Q3 2010	3,680		7.60	11.75		No	4	11
Q4 2010	3,680		7.60	11.75		No	4	10
2011	7,300		7.70	11.50		No	7	18
Call Options:								
Q3 2010	22,570			10.01		No	42	
Q4 2010	34,040			10.08		No	42	(1)
2011	20,987			8.00		No	35	(3)
2012	262,605			7.90		No	14	(76)
2013 2020	904,428			8.08		No	89	(468)
Put Options:								
Q3 2010	(7,360)		4.75			No	1	(2)
Q4 2010	(7,360)		5.38			No	5	(6)
2011	(51,220)		5.53			No	31	(44)
Knockout Swaps:								
Q4 2010	4,880	8.74	6.56			No		1
2011	23,650	9.86	6.29			No		11
Basis Protection Swaps (Non-Appalachian Basin):								
2011	45,090				(0.82)	No	(3)	(21)
2012 2018	57,961				(0.90)	No	(3)	(29)
Basis Protection Swaps (Appalachian Basin):								
Q3 2010	2,660				0.26	No		
Q4 2010	2,732				0.26	No		1
2011 2022	12,220				0.25	No		1
Total Natural Gas							268	553

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		Weighted Average Price						
	Volume	**Fixed**	**Put**	**Call**	**Differential**	**Cash Flow Hedge**	**Net Premiums**	**Fair Value**
Oil:	**(mbbl)**		**(per bbl)**				**($ in millions)**	
Swaps:								
Q3 2010	460	$ 85.86	$	$	$	Yes	$	$ 4
Q4 2010	460	85.86				Yes		4
Other Swaps[b]:								
Q3 2010	644	91.12				No		9
Q4 2010	644	91.12				No		9
2011	3,285	91.17				No		(9)
2012 2013	3,655	100.00				No		(22)
Call Options:								
Q3 2010	368			101.25		No	(3)	
Q4 2010	368			101.25		No	(3)	(1)
2011[c]	5,475			71.35		No		(38)
2012 2015[c]	32,701			87.07		No		(412)
Knock-Out Swaps:								
Q3 2010	1,196	90.25	60.00			No		16
Q4 2010	1,196	90.25	60.00			No		12
2011	1,095	104.75	60.00			No		15
2012	732	109.50	60.00			No		7
Total Oil							(6)	(406)
Total Natural Gas and Oil							$ 262	$ 147

(a) Included in Natural Gas Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2010 is 4,600 bbtu at a weighted average fixed swap price of $10.00/mmbtu, and in 2011 is 47,450 bbtu at a weighted average fixed swap price of $10.18/mmbtu.

(b) Included in Oil Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2011 is 3,285 mbbl at a weighted average fixed price of $91.17/bbl and in 2012 2013 is 3,655 mbbl at a weighted average fixed price of $100.00/bbl.

(c) Included in Oil Call Options are natural gas liquid call options in the amount of 5,000 bbls per day at $39.06/bbl for 2011 and $38.01/bbl for 2012.

We have determined the fair value of our derivative instruments utilizing established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. Future risk related to counterparties not being able to meet their obligations has been mitigated under our secured hedging facility which requires counterparties to post collateral if their obligations to Chesapeake are in excess of defined thresholds. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors.

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The table below reconciles the Current Period change in fair value of our natural gas and oil derivatives. Of the $147 million fair value asset, as of June 30, 2010, $965 million relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $196 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($818) million relates to contracts maturing after 12 months. All transactions hedged as of June 30, 2010 are expected to mature by December 31, 2022.

	2010 ($ in millions)
Fair value of contracts outstanding, as of January 1	$ 21
Change in fair value of contracts	898
Fair value of contracts when entered into	(38)
Contracts realized or otherwise settled	(821)
Fair value of contracts when closed	87
Fair value of contracts outstanding, as of June 30	$ 147

The change in natural gas and oil prices during the Current Period increased the value of our derivative assets by $898 million. This gain is recorded in natural gas and oil sales or in accumulated other comprehensive income. We entered into new contracts which had premiums of $38 million, and a liability was recorded. We settled contracts, reducing our assets by $821 million, and we closed out contracts, increasing our assets by $87 million. The realized gain will be recorded in natural gas and oil sales in the month of related production.

Pursuant to accounting guidance for derivatives and hedging, certain derivatives qualify for designation as cash flow hedges. Following these provisions, 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 accumulated other comprehensive income until the hedged item is recognized in earnings as the physical transactions being hedged occur. Any change in fair value resulting from ineffectiveness is currently recognized in natural gas and oil sales as unrealized gains (losses). 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 natural gas and oil sales. Realized gains (losses) are included in natural gas and oil sales in the month of related production.

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 June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	($ in millions)			
Natural gas and oil sales	$ 984	$ 717	$ 2,169	$ 1,495
Realized gains (losses) on natural gas and oil derivatives	573	597	972	1,115
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	(378)	(253)	(58)	(206)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	(18)	36	(24)	90
Total natural gas and oil sales	$ 1,161	$ 1,097	$ 3,059	$ 2,494

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Interest Rate Risk

The table below presents principal cash flows ($ in millions) and related weighted average interest rates by expected maturity dates.

	Years of Maturity						
	2010	2011	2012	2013	2014	Thereafter	Total
Liabilities:							
Long-term debt fixed rate[(a)]	$	$	$	$ 500	$ 300	$ 8,944	$ 9,744
Average interest rate				7.63%	7.00%	5.98%	6.09%
Long-term debt variable rate	$	$	$ 1,521	$	$	$	$ 1,521
Average interest rate			3.36%				3.36%

(a) This amount does not include the discount included in long-term debt of ($832) million and interest rate derivatives of $68 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 facilities. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of fluctuations in earnings or cash flow due to changes in market interest rates. However, changes in interest rates do affect the fair value of our fixed-rate debt.

Interest Rate Derivatives

To mitigate our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. As of June 30, 2010, our interest rate derivative instruments were comprised of the following types of instruments:

Swaps: Chesapeake enters into fixed-to-floating interest rate swaps (we receive a fixed interest rate and pay a floating market rate) to mitigate our exposure to changes in the fair value of our senior notes. We enter into floating-to-fixed interest rate swaps (we receive a floating market rate and a pay fixed interest rate) to manage our interest rate exposure related to our bank credit facility borrowings.

Collars: These instruments contain a fixed floor rate (floor) and a ceiling rate (cap). If the floating rate is above the cap, we have a net receivable from the counterparty and if the floating rate is below the floor, we have a net payable to the counterparty. If the floating rate is between the floor and the cap, there is no payment due from either party. Collars are used to manage our interest rate exposure related to our bank credit facilities borrowings.

Call options: Occasionally we sell call options for a premium when we think it is more likely that the option will expire unexercised. The option allows the counterparty to terminate an open swap at a specific date.

Swaptions: Occasionally we sell an option to a counterparty for a premium which allows the counterparty to enter into a swap with us on a specific date.

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As of June 30, 2010, the following interest rate derivatives were outstanding:

Fixed to Floating:	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Weighted Average Rate Floating[b]	Fair Value Hedge	Net Premiums ($ in millions)	Fair Value ($ in millions)
Swaps						
Mature 2017 2020	$ 750	6.88%	3 6 mL plus 366 bp	No	$ 5	$ 10
Call Options						
Expire Q4 2010	$ 250	6.88%	3 mL plus 287 bp	No	7	(14)
Swaption						
Expire Q3 2010 Q4 2010	$ 400	7.63%	3 6 mL plus 400 bp	No	5	(1)
Floating to Fixed:						
Swaps						
Mature Q3 2010 2012	$ 1,375	3.30%	1 6 mL	No		(37)
Collars[a]						
Mature Q3 2010	$ 250	4.52%	6 mL	No		(1)
					$ 17	$ (43)

(a) The collars have ceiling and floor fixed interest rates of 5.37% and 4.52%, respectively.

(b) Month LIBOR has been abbreviated mL and basis points has been abbreviated bp .

In the Current Period, we closed interest rate derivatives which were designated as fair value hedges for gains totaling $5 million. These gains are currently reported as an adjustment to our senior note liability, and will be amortized as a reduction to realized interest expense over the remaining seven-year term of the related senior notes.

For interest rate derivative instruments designated as fair value hedges 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 interest rate derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. The components of interest expense for the Current Period and the Prior Period are presented below.

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	($ in millions)			
Interest expense on senior notes	$ (190)	$ (196)	$ (383)	$ (378)
Interest expense on credit facilities	(12)	(17)	(24)	(29)
Capitalized interest	179	152	340	314
Realized gains (losses) on interest rate derivatives	2	5	4	12
Unrealized gains (losses) on interest rate derivatives	49	42	77	87
Amortization of loan discount and other	(12)	(8)	(23)	(14)
Total interest (expense) income	$ 16	$ (22)	$ (9)	$ (8)

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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. The fair value of the cross currency swap is recorded on the condensed consolidated balance sheet as a liability of $118 million at June 30, 2010. The euro-denominated debt in notes payable has been adjusted to $738 million at June 30, 2010 using an exchange rate of 1.2291 to 1.00.

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 were effective as of June 30, 2010.

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***

We refer you 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.

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 2009 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

The following table presents information about repurchases of our common stock during the three months ended June 30, 2010:

Period	Total Number of Shares Purchased[(a)]	Average Price Paid Per Share (a)	Total Number Of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs[(b)]
April 1, 2010 through April 30, 2010	13,214	$ 23.92		
May 1, 2010 through May 31, 2010	10,489	$ 22.36		
June 1, 2010 through June 30, 2010	10,762	$ 21.43		
Total	34,465	$ 22.57		

(a) Represents the surrender to the company of 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 deferred compensation plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of company contributions.

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

Not applicable.

ITEM 4. ***(Removed and Reserved)***

Not applicable.

ITEM 5. ***Other Information***

Not applicable.

ITEM 6. ***Exhibits***

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

		Incorporated by Reference					
Exhibit Number	**Exhibit Description**	**Form**	**SEC File Number**	**Exhibit**	**Filing Date**	**Filed Herewith**	**Furnished Herewith**
3.1.1	Chesapeake s Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	08/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B).	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock.	10-Q	001-13726	3.1.6	08/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.					X	
3.2.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.4.1	Fifth Amendment dated as of May 11, 2010 to Seventh Amended and Restated Credit Agreement, dated as of November 2, 2007, among Chesapeake Energy Corporation, as the Company, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as Administrative Agent, The Royal Bank of Scotland, as Syndication Agent, and Bank of America, N.A., SunTrust Bank and BNP Paribas, as Co-Documentation Agents, and the several lenders from time to time parties thereto.					X	
10.1.14	Chesapeake s Amended and Restated Long Term Incentive Plan.	8-K	001-13726	10.1.14	06/17/2010		
10.1.14.1	Form of Restricted Stock Award Agreement for the Long Term Incentive Plan.					X	
12	Ratios of Earnings to Fixed Charges and Combined 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	

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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	
101.INS	XBRL Instance Document.						X
101.SCH	XBRL Taxonomy Extension Schema Document.						X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.						X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.						X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.						X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.						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

Date: August 9, 2010

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon

Chairman of the Board and

Chief Executive Officer

Date: August 9, 2010

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland

Executive Vice President and

Chief Financial Officer

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3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	05/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.					X	
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