CHESAPEAKE ENERGY CORP
Form 10-Q
November 09, 2010

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended September 30, 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 November 3, 2010, there were 653,915,007 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2010	December 31, 2009
	($ in millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 609	$ 307
Accounts receivable	1,454	1,325
Short-term derivative instruments	1,087	692
Deferred income tax asset		24
Other	123	98
Total Current Assets	3,273	2,446
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full-cost accounting:		
Evaluated natural gas and oil properties	37,391	35,007
Unevaluated properties	12,706	10,005
Less: accumulated depreciation, depletion and amortization of natural gas and oil properties	(25,232)	(24,220)
Total natural gas and oil properties, at cost based on full-cost accounting	24,865	20,792
Other property and equipment:		
Natural gas gathering systems and treating plants	1,837	3,516
Buildings and land	1,751	1,673
Drilling rigs and equipment	763	687
Natural gas compressors	284	325
Other	649	550
Less: accumulated depreciation and amortization of other property and equipment	(669)	(833)
Total other property and equipment	4,615	5,918
Total Property and Equipment	29,480	26,710
OTHER ASSETS:		
Investments	1,189	404
Long-term derivative instruments	29	60
Other assets	362	294
Total Other Assets	1,580	758
TOTAL ASSETS	$ 34,333	$ 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)

	September 30, 2010	December 31, 2009
	($ in millions)	
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 1,773	$ 957
Short-term derivative instruments	26	27
Accrued liabilities	1,171	920
Deferred income taxes	379	
Income taxes payable	2	1
Revenues and royalties due others	650	565
Accrued interest	122	218
Total Current Liabilities	4,123	2,688
LONG-TERM LIABILITIES:		
Long-term debt, net	11,445	12,295
Deferred income tax liabilities	1,839	1,059
Long-term derivative instruments	967	787
Asset retirement obligations	291	282
Revenues and royalties due others	75	73
Other liabilities	320	389
Total Long-Term Liabilities	14,937	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 September 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 September 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 September 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 September 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 September 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, 655,330,601 and 648,549,165 shares issued at September 30, 2010 and December 31, 2009, respectively	7	6
Paid-in capital	12,138	12,146
Retained earnings (deficit)	57	(1,261)
Accumulated other comprehensive income, net of tax of ($16) million and ($62) million, respectively	25	102
Less: treasury stock, at cost; 1,049,382 and 877,205 common shares as of September 30, 2010 and December 31, 2009, respectively	(19)	(15)

Total Chesapeake Stockholders Equity	15,273	11,444
Noncontrolling interest		897
Total Equity	15,273	12,341
TOTAL LIABILITIES AND EQUITY	$ 34,333	$ 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	($ in millions, except per share data)			
REVENUES:				
Natural gas and oil sales	$ 1,639	$ 1,187	$ 4,698	$ 3,681
Marketing, gathering and compression sales	883	575	2,520	1,660
Service operations revenue	59	49	173	139
Total Revenues	2,581	1,811	7,391	5,480
OPERATING COSTS:				
Production expenses	231	218	652	670
Production taxes	34	25	119	71
General and administrative expenses	125	95	340	259
Marketing, gathering and compression expenses	851	546	2,429	1,569
Service operations expense	52	49	154	136
Natural gas and oil depreciation, depletion and amortization	378	295	1,025	1,037
Depreciation and amortization of other assets	56	62	159	177
Impairment or loss on sale of other property and equipment	37	124	37	159
Impairment of natural gas and oil properties				9,600
Restructuring costs				34
Total Operating Costs	1,764	1,414	4,915	13,712
INCOME (LOSS) FROM OPERATIONS	817	397	2,476	(8,232)
OTHER INCOME (EXPENSE):				
Interest expense	(3)	(43)	(12)	(52)
Loss on redemptions or exchanges of Chesapeake debt	(59)	(17)	(130)	(19)
Impairment of investments	(16)		(16)	(162)
Other income (expense)	168	(30)	202	(25)
Total Other Income (Expense)	90	(90)	44	(258)
INCOME (LOSS) BEFORE INCOME TAXES	907	307	2,520	(8,490)
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	(1)		4	1
Deferred income taxes	350	115	966	(3,185)
Total Income Tax Expense (Benefit)	349	115	970	(3,184)

NET INCOME (LOSS)	558	192	1,550	(5,306)
Net (income) loss attributable to noncontrolling interest				
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	558	192	1,550	(5,306)
Preferred stock dividends	(43)	(6)	(68)	(18)
NET INCOME (LOSS) AVAILABLE TO CHESAPEAKE COMMON STOCKHOLDERS	$ 515	$ 186	$ 1,482	$ (5,324)
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$ 0.81	$ 0.30	$ 2.35	$ (8.78)
Diluted	$ 0.75	$ 0.30	$ 2.24	$ (8.78)
CASH DIVIDEND DECLARED PER COMMON SHARE	$ 0.075	$ 0.075	$ 0.225	$ 0.225
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	632	619	631	606
Diluted	744	626	692	606

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2010	2009
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,550	$ (5,306)
ADJUSTMENTS TO RECONCILE NET INCOME (LOSS) TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,184	1,214
Deferred income tax expense (benefit)	966	(3,185)
Unrealized (gains) losses on derivatives	(45)	295
Realized gains on financing derivatives	(436)	(53)
Stock-based compensation	111	104
Accretion of discount on contingent convertible notes	58	60
(Gain) loss on equity investments	(120)	32
Loss on redemptions or exchanges of Chesapeake debt	29	19
Impairment or loss on sale of other property and equipment	37	159
Impairment of natural gas and oil properties		9,600
Impairment of investments	16	162
Restructuring costs		12
Other	12	8
Change in assets and liabilities	609	10
Cash provided by operating activities	3,971	3,131
CASH FLOWS FROM INVESTING ACTIVITIES:		
Exploration and development of natural gas and oil properties	(3,718)	(2,790)
Acquisitions of natural gas and oil proved and unproved properties	(4,217)	(1,348)
Additions to other property and equipment	(968)	(1,362)
Proceeds from divestitures of proved and unproved properties	3,107	1,729
Proceeds from sales of other assets	328	157
Additions to investments	(113)	(40)
Deposits on acquisitions	(95)	
Other	11	
Cash used in investing activities	(5,665)	(3,654)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	10,458	5,563
Payments on credit facilities borrowings	(9,863)	(7,866)
Proceeds from issuance of preferred stock, net of offering costs	2,562	
Proceeds from issuance of senior notes, net of offering costs	1,967	1,346
Cash paid to redeem Chesapeake debt	(3,434)	
Cash paid for common stock dividends	(142)	(135)
Cash paid for preferred stock dividends	(49)	(18)

Realized gains on financing derivatives		436		19
Proceeds from sale of noncontrolling interest in midstream joint venture				588
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		116		(305)
Other		(55)		(97)
Cash provided by (used in) financing activities		1,996		(706)
Net increase (decrease) in cash and cash equivalents		302		(1,229)
Cash and cash equivalents, beginning of period		307		1,749
Cash and cash equivalents, end of period	$	609	$	520

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

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 103	$ 111
Income taxes, net of refunds received	$ (291)	$ 176

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

As of September 30, 2010 and 2009, dividends payable on our common and preferred stock were $90 million and $52 million, respectively.

For the nine months ended September 30, 2010 and 2009, natural gas and oil properties were adjusted by $116 million and ($72) million, respectively, as a result of an increase (decrease) in accrued exploration and development costs.

For the nine months ended September 30, 2010 and 2009, other property and equipment were adjusted by ($8) million and ($31) million, respectively, as a result of an increase (decrease) in accrued costs.

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

We recorded non-cash asset reductions to natural gas gathering systems of $2 million and $3 million for the nine months ended September 30, 2010 and 2009, respectively, for asset retirement obligations.

During the nine months ended September 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 nine months ended September 30, 2009, we issued 24,822,832 shares of common stock, valued at $429 million, for the purchase of proved and unproved properties pursuant to an acquisition shelf registration statement.

During the nine months ended September 30, 2009, holders of our 2.25% Contingent Convertible Senior Notes due 2038 exchanged approximately $238 million in aggregate principal amount for an aggregate of 6,707,321 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)

	Nine Months Ended September 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	
Conversion or exchange of 5,000 and 146,801 shares of preferred stock for common stock	(1)	(39)
Balance, end of period	3,065	466
COMMON STOCK:		
Balance, beginning of period	6	6
Conversion or exchange of convertible notes and preferred stock for 319,274 and 8,129,746 shares of common stock		
Issuance of 0 and 24,822,832 shares of common stock for the purchase of proved and unproved properties		
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 24,822,832 shares of common stock for the purchase of proved and unproved properties		420
Conversion or exchange of convertible notes and preferred stock for 319,274 and 8,129,746 shares of common stock	9	203
Stock-based compensation	174	143
Offering expenses	(39)	
Dividends on common stock	(95)	(138)
Dividends on preferred stock	(44)	(17)
Allocation of joint venture capital to Global Infrastructure Partners		(263)
Tax benefit (reduction in tax benefit) from exercise of stock-based compensation	(13)	(47)
Balance, end of period	12,138	11,981
RETAINED EARNINGS (DEFICIT):		
Balance, beginning of period	(1,261)	4,569
Net income (loss)	1,550	(5,306)
Cumulative effect of accounting change, net of income taxes of $89 million	(142)	
Dividends on common stock	(47)	
Dividends on preferred stock	(43)	
Balance, end of period	57	(737)

ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	102	267
Hedging activity	(70)	(60)
Investment activity	(7)	67
Balance, end of period	25	274
TREASURY STOCK COMMON:		
Balance, beginning of period	(15)	(10)
Purchase of 179,140 and 115,430 shares for company benefit plans	(4)	(2)
Release of 6,963 and 6,152 shares for company benefit plans		
Balance, end of period	(19)	(12)
TOTAL CHESAPEAKE STOCKHOLDERS EQUITY	15,273	11,978
NONCONTROLLING INTEREST:		
Balance, beginning of period	897	
Sale of noncontrolling interest in midstream joint venture		588
Allocation of joint venture capital to Global Infrastructure Partners		263
Deconsolidation of investment in CMP	(897)	
Balance, end of period		851
TOTAL EQUITY	$ 15,273	$ 12,829

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 September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	($ in millions)			
Net income (loss)	$ 558	$ 192	$ 1,550	$ (5,306)
Other comprehensive income (loss), net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $39 million, $38 million, $153 million and $372 million	65	62	251	609
Reclassification of gain on settled contracts, net of income taxes of ($68) million, ($144) million, ($203) million and ($377) million	(112)	(236)	(333)	(617)
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($2) million, $2 million, $8 million and ($31) million	(3)	5	12	(52)
Unrealized (gain) loss on marketable securities, net of income taxes of $1 million, $4 million, ($4) million and $14 million	1	6	(7)	24
Reclassification of loss on investments, net of income taxes of $0, $0, $0 and $26 million				43
Comprehensive income (loss)	509	29	1,473	(5,299)
(Income) loss attributable to noncontrolling interest				
Comprehensive income (loss) available to Chesapeake	$ 509	$ 29	$ 1,473	$ (5,299)

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 nine months ended September 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 nine months ended September 30, 2010 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2009 (the Prior Quarter and the Prior Period , respectively).

Cumulative Effect of Accounting Change

Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we ceased consolidating our 50/50 midstream joint venture with Global Infrastructure Partners within our financial statements and began to account for the joint venture 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 September 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.

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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 September 30, 2010 and December 31, 2009 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2010		December 31, 2009	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (bbtu):				
Fixed-price swaps	616,190	$ 1,378	492,053	$ 662
Fixed-price collars	10,980	37	74,240	92
Call options	1,333,619	(481)	996,750	(541)
Put options	(58,580)	(75)	(69,620)	(50)
Fixed-price knockout swaps	28,530	5	38,370	17
Basis protection swaps	154,502	(52)	125,469	(50)
Total natural gas	2,085,241	812	1,657,262	130
Oil (mbbl):				
Fixed-price swaps	8,044	(28)	5,475	3
Call options	42,259	(622)	14,975	(144)
Fixed-price knockout swaps	3,023	35	6,572	32
Total oil	53,326	(615)	27,022	(109)
Total estimated fair value		$ 197		$ 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	($ in millions)			
Natural gas and oil sales	$ 1,074	$ 785	$ 3,243	$ 2,280
Realized gains (losses) on natural gas and oil derivatives	512	687	1,484	1,802
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	48	(278)	(9)	(484)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	5	(7)	(20)	83
Total natural gas and oil sales	$ 1,639	$ 1,187	$ 4,698	$ 3,681

Based upon the market prices at September 30, 2010, we expect to transfer approximately $188 million (net of income taxes) of the gain included in the accumulated other comprehensive income balance to net income (loss) during the next 12 months in the related month of production. All transactions hedged as of September 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 September 30, 2010, we had hedged a total of 2.3 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 September 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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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 September 30, 2010 and December 31, 2009 are provided below.

	September 30, 2010		December 31, 2009	
	Notional Amount	Fair Value	Notional Amount	Fair Value
	($ in millions)			
Interest rate:				
Swaps	$ 1,300	$ (13)	$ 2,925	$ (113)
Collars			250	(6)
Call options	250	(26)	250	(2)
Swaptions	250		500	(11)
Totals	$ 1,800	$ (39)	$ 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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	($ in millions)			
Interest expense on senior notes	$ 167	$ 195	$ 550	$ 572
Interest expense on credit facilities	18	18	42	47
Capitalized interest	(185)	(153)	(525)	(467)
Realized (gains) losses on interest rate derivatives	(2)	(7)	(6)	(19)
Unrealized (gains) losses on interest rate derivatives	2	(20)	(75)	(106)
Amortization of loan discount and other	3	10	26	25

Total interest expense	$ 3	$ 43	$ 12	$ 52

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 recognize $36 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. 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

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balance sheet as a liability of $35 million at September 30, 2010. The euro-denominated debt in long-term debt has been adjusted to $816 million at September 30, 2010 using an exchange rate of $1.3601 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 sheets 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 September 30, 2010 and December 31, 2009, on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value September 30, 2010	Fair Value December 31, 2009
		($ in millions)	
Asset Derivatives:			
Derivatives designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$ 438	$ 417
Commodity contracts	Long-term derivative instruments	41	36
Foreign currency contracts	Long-term derivative instruments		43
Total		479	496
Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	794	318
Commodity contracts	Long-term derivative instruments	367	66
Interest rate contracts	Long-term derivative instruments	29	
Total		1,190	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	(35)	
Total		(35)	(12)

Derivatives not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(145)	(42)
Commodity contracts	Long-term derivative instruments	(1,298)	(768)
Interest rate contracts	Short-term derivative instruments	(26)	(27)
Interest rate contracts	Long-term derivative instruments	(42)	(94)
Total		(1,511)	(931)
Total derivative instruments		$ 123	$ (63)

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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:

Fair Value Derivatives	Location of Gain (Loss)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
		($ in millions)			
Interest rate contracts	Interest expense[(a)]	$ 3	$ 13	$ 16	$ 31

(a) Interest expense on items hedged during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period was $0, $33 million, $15 million and $66 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:

Cash Flow Derivatives	Location of Gain (Loss)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
		($ in millions)			
Gain (Loss) Recognized in AOCI (Effective Portion)					
Commodity contracts	AOCI	$ 94	$ 107	$ 458	$ 819
Foreign exchange contracts	AOCI	5	1	(34)	79
		$ 99	$ 108	$ 424	$ 898
Gain (Loss) Reclassified from AOCI (Effective Portion)					
Commodity contracts	Natural gas and oil sales	$ 179	$ 381	$ 535	$ 994
		$ 179	$ 381	$ 535	$ 994

Gain (Loss) Recognized (Ineffective Portion and Amount Excluded from Effectiveness Testing)[(a)]					
Commodity contracts	Natural gas and oil sales	$ 2	$ (7)	$ (95)	$ 83
		$ 2	$ (7)	$ (95)	$ 83

(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 $5 million, ($7) million, ($20) million and $83 million related to the ineffective portion of our cash flow derivatives and ($3) million, $0, ($75) 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:

Non-Qualifying Derivatives	**Location of Gain (Loss)**	**Three Months Ended September 30, 2010**	**Three Months Ended September 30, 2009**	**Nine Months Ended September 30, 2010**	**Nine Months Ended September 30, 2009**
		($ in millions)			
Commodity contracts	Natural gas and oil sales	$ 384	$ 28	$ 1,015	$ 324
Interest rate contracts	Interest expense	(3)	14	65	94
	Total	$ 381	$ 42	$ 1,080	$ 418

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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 September 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 and the Current Period, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. During the Prior Period, we recognized $13 million 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 defendants motion to dismiss was denied on September 2, 2010. 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 pursuant to stipulation.

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 s motion to dismiss was granted on February 28, 2010 and plaintiffs were given leave to amend. 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 in the Oklahoma Court of Civil Appeals.

We are currently unable to assess the probability of loss or estimate a range of potential loss associated with the foregoing cases. It is inherently difficult to predict the outcome of any litigation, and these proceedings are at an early stage.

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.

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The company has satisfactorily resolved most of these suits but a few are pending, either at the trial court or appellate level. 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.

Environmental Risk

Due to the nature of the natural gas and oil business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at September 30, 2010.

Rig Leases

In a series of transactions since 2006, our drilling subsidiaries have sold 85 drilling rigs and related equipment for $704 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 $97 million annually. The lease obligations are guaranteed by Chesapeake and certain of its 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 five and one-half to 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 September 30, 2010, the minimum aggregate undiscounted future rig lease payments were approximately $478 million.

Compressor Leases

Through various transactions since 2007, our compression subsidiary has sold 2,234 compressors, a significant portion of its compressor fleet, for $517 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 $77 million annually. The lease obligations are guaranteed by Chesapeake and certain of its 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 September 30, 2010, the minimum aggregate undiscounted future compressor lease payments were approximately $441 million.

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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 are presented below:

	September 30, 2010 ($ in millions)
2010	$ 82
2011	378
2012	378
2013	364
2014	344
2015 2099	2,449
Total	$ 3,995

Drilling and Rig Purchase Contracts

Currently, Chesapeake has contracts with various drilling contractors to lease approximately 46 rigs with terms of four months to four years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2010, the aggregate undiscounted drilling rig commitment was approximately $204 million.

In September 2010, Chesapeake entered into a contract to purchase 7 rigs for $85 million. As of September 30, 2010, we had made a $9 million deposit and have a remaining commitment of $76 million. The transaction is expected to close in December 2010.

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

We are a party to a gas gathering agreement with a subsidiary of Chesapeake Midstream Partners, L.P. (see Note 9), pursuant to which we have 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. 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 September 30, 2010 were as follows:

	Bcf
2010	129
2011	313
2012	325
2013	338
2014	351
After 2014	1,686
Total	3,142

In addition, Chesapeake has entered into commitments to deliver approximately 530 bcf through September 2021 to third-party midstream companies.

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(Unaudited)

Net Acreage Maintenance Commitments

Under the terms of our joint development agreements with our joint venture partners, Statoil and Total (see Note 8), 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.

Other Commitments

As of September 30, 2010, we had made commitments to acquire additional leasehold in various transactions during the next twelve months for approximately $1.7 billion, including the acquisition of a significant additional position in the Appalachian Basin from privately-held Anschutz Corporation which is expected to close in November 2010.

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 Quarter and 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 Prior Quarter and the Prior Period, as the effect was antidilutive.

	Shares (in millions)	Net Income Adjustments ($ in millions)
Three Months Ended September 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
Nine Months Ended September 30, 2009:		
Common stock equivalent of our preferred stock outstanding:		
5.00% cumulative convertible preferred stock (series 2005B)	5	$ 8
4.50% cumulative convertible preferred stock	6	$ 9
Common stock equivalent of our preferred stock outstanding prior to conversion:		
6.25% mandatory convertible preferred stock	1	$ 1
Outstanding stock options	1	$
Unvested restricted stock	5	$

For the Prior Period, as a result of the net loss to Chesapeake common stockholders, there was no difference between basic weighted average shares outstanding, which are used in computing basic EPS, and diluted weighted average shares, which are used in computing EPS assuming dilution.

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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 September 30, 2010:			
Basic EPS	$ 515	632	$ 0.81
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	21	56	
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	16	40	
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	2	5	
Common shares assumed issued for 4.50% cumulative convertible preferred stock	3	6	
Outstanding stock options		1	
Unvested restricted stock		4	
Diluted EPS	$ 557	744	$ 0.75
Three Months Ended September 30, 2009:			
Basic EPS	$ 186	619	$ 0.30
Effect of Dilutive Securities:			
Outstanding stock options		1	
Unvested restricted stock		6	
Diluted EPS	$ 186	626	$ 0.30
Nine Months Ended September 30, 2010:			
Basic EPS	$ 1,482	631	$ 2.35
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	28	24		
Common shares assumed issued for 5.75% cumulative convertible preferred stock (series A)	23	20		
Common shares assumed issued for 5.00% cumulative convertible preferred stock (series 2005B)	8	5		
Common shares assumed issued for 4.50% cumulative convertible preferred stock	9	6		
Outstanding stock options		1		
Unvested restricted stock		5		
Diluted EPS	$ 1,550	692	$	2.24

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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 nine months ended September 30, 2010 and 2009:

	2010	2009
	(in thousands)	
Shares issued at January 1	648,549	607,953
Restricted stock issuances (net of forfeitures)	6,108	3,940
Stock option exercises	354	429
Convertible note exchanges	299	6,707
Preferred stock conversions/exchanges	21	1,422
Common stock issued for the purchase of proved and unproved properties		24,823
Shares issued at September 30	655,331	645,274

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 Period, $7 million was allocated to the debt component of the notes and the remaining $4 million was allocated to the equity conversion feature of the notes 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 a $2 million loss (including a nominal amount of deferred charges associated with the exchanges).

In the Prior Period, we privately exchanged approximately $238 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 6,707,321 shares of our common stock valued at approximately $164 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 70% of the face value of the notes. Of the $238 million principal amount of convertible notes exchanged in the Prior Period, $148 million was allocated to the debt component of the notes and the remaining $90 million was allocated to the equity conversion feature of the notes 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 a $19 million loss (including $3 million of deferred charges associated with the exchanges that were written off).

In the Prior Period, pursuant to an acquisition shelf registration statement, we issued 24,822,832 shares of common stock valued at $429 million for the purchase of proved and unproved properties.

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Preferred Shares

The following is a summary of the changes in our preferred shares outstanding for the nine months ended September 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 September 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 September 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 also granted an option to such purchasers to place additional shares of the preferred stock. Upon the exercise of the placement option, we issued an additional 900,000 shares of 5.75% Cumulative Convertible Non-Voting Preferred Stock on June 18, 2010 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.

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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 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, service operations expense or restructuring costs. We recorded the following stock-based compensation during the Current Quarter, the Prior Quarter, the Current Period and the Prior Period:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	($ in millions)			
Natural gas and oil properties	$ 30	$ 27	$ 95	$ 85
General and administrative expenses	21	22	63	60
Production expenses	9	8	27	26
Marketing, gathering and compression expenses	5	4	13	12
Service operations expense	2	2	7	6
Restructuring costs				9
Total	$ 67	$ 63	$ 205	$ 198

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 for the nine months ended September 30, 2010 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	8,901	$ 24.21
Vested	(5,332)	$ 32.49
Forfeited	(885)	$ 30.49
Unvested shares as of September 30, 2010	21,909	$ 28.68

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $124 million based on the stock price at the time of vesting.

As of September 30, 2010, there was $425 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 2.4 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 $14 million, $36 million, $15 million and $48 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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The following table provides information related to stock option activity for the nine months ended September 30, 2010:

	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	(366)	$ 6.15		
Expired		$		
Outstanding at September 30, 2010	1,917	$ 8.78	2.22	$ 27
Exercisable at September 30, 2010	1,917	$ 8.78	2.22	$ 27

(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 Quarter, the Prior Quarter, the Current Period and the Prior Period we recognized excess tax benefits related to stock options of $1 million, $1 million, $2 million and $1 million which were recorded as adjustments to additional paid-in capital and deferred income taxes.

6. Debt

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

	September 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		300
7.5% senior notes due 2014		300
6.375% senior notes due 2015		600
9.5% senior notes due 2015	1,425	1,425
6.625% senior notes due 2016		600

6.875% senior notes due 2016		670
6.25% euro-denominated senior notes due 2017(a)	816	860
6.5% senior notes due 2017	1,100	1,100
6.25% senior notes due 2018		600
6.875% senior notes due 2018	600	
7.25% senior notes due 2018	800	800
6.625% senior notes due 2020	1,400	
6.875% senior notes due 2020	500	500
2.75% contingent convertible senior notes due 2035(b)	451	451
2.5% contingent convertible senior notes due 2037(b)	1,378	1,378
2.25% contingent convertible senior notes due 2038(b)	752	763
Corporate revolving bank credit facility	2,237	1,892
Midstream revolving bank credit facility	250	
Midstream joint venture revolving bank credit facility(c)		44
Discount on senior notes(d)	(800)	(921)
Interest rate derivatives(e)	36	69
Total notes payable and long-term debt	$ 11,445	$ 12,295

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3601 to 1.00 and $1.4332 to 1.00 as of September 30, 2010 and December 31, 2009, respectively. See Note 2 for information on our related foreign currency derivatives.

(b) 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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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 third 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 fourth 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

(c) Effective January 1, 2010, our midstream joint venture was no longer consolidated in accordance with the new authoritative guidance. See Notes 1 and 9 for further details.

(d) Included in this discount is $731 million at September 30, 2010 and $794 million at December 31, 2009 associated with the equity component of our contingent convertible senior notes.

(e) 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. Our senior notes 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.

On July 22, 2010, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. Associated with the redemption, we recognized a loss of $19 million in the Current Quarter.

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.

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On August 17, 2010, we completed a public offering of $2.0 billion aggregate principal amount of senior notes for net proceeds of approximately $1.967 billion. The offering consisted of $600 million of 6.875% Senior Notes due 2018 and $1.4 billion of 6.625% Senior Notes due 2020. Both series were priced at par.

On August 30, 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. On September 16, 2010, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 million in the Current Quarter.

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	$ 300
Maturity date	November 2012	July 2015
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of September 30, 2010	$ 2,237	$ 250
Letters of credit outstanding as of September 30, 2010	$ 13	$

(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.

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, neither of our credit facilities contains 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 and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at September 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 $50 million or more, 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

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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 certain of our other wholly owned subsidiaries.

Midstream Credit Facility

Our $300 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 1.75% to 2.25% per annum according to the most recent leverage ratio described below or (ii) the LIBOR plus a margin that varies from 2.75% to 3.25% per annum according to the most recent leverage ratio. The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent leverage ratio. 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 agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our master limited partnership midstream affiliate, Chesapeake Midstream Partners, L.P. We were in compliance with all covenants under the agreement at September 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 September 30, 2010, 111 assets were leased and the minimum aggregate undiscounted future lease payments were approximately $832 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 $1.045 billion, $716 million, $2.978 billion and $2.009 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	Intercompany Eliminations	Consolidated Total
			($ in millions)		
Three Months Ended September 30, 2010:					
Revenues	$ 1,639	$ 1,928	$ 187	$ (1,173)	$ 2,581
Intersegment revenues		(1,045)	(128)	1,173	
Total revenues	$ 1,639	$ 883	$ 59	$	$ 2,581
Income (loss) before income taxes	$ 822	$ 96	$ (7)	$ (4)	$ 907
Three Months Ended September 30, 2009:					
Revenues	$ 1,187	$ 1,291	$ 69	$ (736)	$ 1,811
Intersegment revenues		(716)	(20)	736	
Total revenues	$ 1,187	$ 575	$ 49	$	$ 1,811
Income (loss) before income taxes	$ 431	$ (111)	$ (19)	$ 6	$ 307
Nine Months Ended September 30, 2010:					
Revenues	$ 4,698	$ 5,498	$ 538	$ (3,343)	$ 7,391
Intersegment revenues		(2,978)	(365)	3,343	
Total revenues	$ 4,698	$ 2,520	$ 173	$	$ 7,391

Income (loss) before income taxes	$ 2,401	$ 152	$ (32)	$ (1)	$ 2,520
Nine Months Ended September 30, 2009:					
Revenues	$ 3,681	$ 3,669	$ 338	$ (2,208)	$ 5,480
Intersegment revenues		(2,009)	(199)	2,208	
Total revenues	$ 3,681	$ 1,660	$ 139	$	$ 5,480
Income (loss) before income taxes	$ (8,354)	$ (82)	$ (53)	$ (1)	$ (8,490)
As of September 30, 2010:					
Total assets	$ 30,945	$ 3,481	$ 721	$ (814)	$ 34,333
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., 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 (plus $78 million of drilling and completion carries due from the effective date of the transaction to the closing date) and is obligated to pay a total of $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 2013.

During the Current Period and Prior Period, our drilling and completion costs included the benefit of approximately $745 million and $959 million, respectively, in drilling and completion carries associated with our shale play joint ventures with Total, Statoil, BP America and Plains Exploration & Production Company as follows:

Shale Play	Joint Venture Partner	Joint Venture Date	Nine Months Ended September 30, 2010	2009
			($ in millions)	
Barnett	Total	January 2010	$ 349	$
Marcellus	Statoil	November 2008	396	85
Fayetteville	BP	September 2008		524
Haynesville	Plains	July 2008		350
			$ 745	$ 959

During the Current Period, as part of our joint venture agreements with Total, Statoil and Plains, we sold interests in additional leasehold in the Barnett, Marcellus and Haynesville shale plays for approximately $395 million.

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

Volumetric Production Payments

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.

On September 30, 2010, we sold certain Chesapeake-operated long-lived producing assets in the Barnett Shale in our eighth VPP transaction for proceeds of approximately $1.15 billion, or $2.93 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 Period, we sold producing properties and gathering systems in Virginia and in the Permian Basin for proceeds of approximately $330 million.

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9. Investments

At September 30, 2010, investments accounted for under the equity method totaled $1.160 billion and investments accounted for under the cost method totaled $29 million. Following is a summary of our investments:

	Approximate % Owned	Accounting Method	Carrying Value September 30, 2010	Carrying Value December 31, 2009
			($ in millions)	
Chesapeake Midstream Partners, L.P.	42%	Equity	$ 666	$
Frac Tech Services, LLC	26%	Equity	347	239
Chaparral Energy, Inc.	20%	Equity	137	103
Gastar Exploration Ltd.	14%	Cost	27	32
Other[(a)]		Cost/Equity	12	30
			$ 1,189	$ 404

(a) In the Current Quarter, we recorded a $16 million impairment of certain other equity investments.

Chesapeake Midstream Partners, L.P. 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, and GIP purchased a 50% interest in, a new joint venture entity. 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, the joint venture was consolidated within our financial statements. Effective January 1, 2010, in accordance with new authoritative guidance for variable interest entities, we changed the accounting for our investment in the joint venture to 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 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. 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 $240 million as of September 30, 2010. This difference is being accreted over 20 years.

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we and GIP formed to own, operate, develop and acquire midstream assets, completed an initial public offering of 24,437,500 common units (including 3,187,500 common units issued pursuant to the exercise of the underwriters' over-allotment option on August 3, 2010) representing limited partner interests and received gross offering proceeds of approximately $513 million at an initial offering price of $21.00 per unit less approximately $38 million for underwriting discounts and commissions, structuring fees and offering expenses. Pursuant to the terms of our contribution agreement with GIP, CHKM distributed the approximate $62 million of net proceeds from the exercise of the over-allotment option to GIP on August 3, 2010. 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 is continuing 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 98.0% interest in CHKM and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2.0% interest in CHKM.

As a result of the initial public offering by CHKM, we recognized a $90 million gain on our investment in the Current Quarter. This gain represented our proportionate share of the excess of offering proceeds over the carrying value of our investment in CHKM.

Frac Tech Services, LLC. The carrying value of our investment in Frac Tech is in excess of our underlying equity in net assets by approximately $190 million as of September 30, 2010. This excess amount is attributed to certain intangibles associated with the specialty services provided by Frac Tech 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 $61 million as of September 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.

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As a result of an additional equity offering by Chaparral to a third party, we recognized a $31 million gain on our investment in the Current Quarter. This gain represented our proportionate share of the excess of offering proceeds over the carrying value of our investment in Chaparral.

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:

	Nine Months Ended September 30, 2009 ($ in millions)
Termination and relocation costs	$ 22
Acceleration of restricted stock awards	9
Other associated costs	3
Total Restructuring Costs	$ 34

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 and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

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. (NYSE Amex: GST) 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 non-performance risk in the valuation of our derivatives using current published credit default swap 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 related interest rate swaps.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
Financial Assets (Liabilities):				
Cash equivalents	$ 609	$	$	$ 609
Investments	27			27
Other long-term assets	42			42
Long-term debt			(816)	(816)
Other long-term liabilities	(42)			(42)
Derivatives:				
Commodity assets		1,387	255	1,642
Commodity liabilities			(1,445)	(1,445)
Interest rate assets			29	29
Interest rate liabilities			(68)	(68)
Foreign currency liabilities			(35)	(35)
Total derivatives		1,387	(1,264)	123
Total	$ 636	$ 1,387	$ (2,080)	$ (57)

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:

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

	($ in millions)			
Financial Assets (Liabilities):				
Cash equivalents	$ 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)

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:

	Derivatives			
	Commodity	Interest Rate	Foreign Currency	Debt
	($ in millions)			
Balance of Level 3 as of January 1, 2010	$ (666)	$ (132)	$ 43	$ (1,398)
Total gains (losses) (realized/unrealized):				
Included in earnings (realized)[(a)]	305	(6)		
Included in earnings or change in net assets (unrealized)[(a)]	(669)	85	(44)	32
Included in other comprehensive income (loss)	(18)		(34)	
Purchases, issuances and settlements	(142)	14		550 [(b)]
Transfers in and out of Level 3				
Balance of Level 3 as of September 30, 2010	$ (1,190)	$ (39)	$ (35)	$ (816)
Balance of Level 3 as of January 1, 2009	$ 431	$ (63)	$ (76)	$ (1,470)
Total gains (losses) (realized/unrealized):				
Included in earnings (realized)[(a)]	778	20		(128)
Included in earnings or change in net assets (unrealized)[(a)]	(380)	106	42	
Included in other comprehensive income (loss)	45		78	
Purchases, issuances and settlements	(835)	(154)		(450)[(b)]
Transfers in and out of Level 3				
Balance of Level 3 as of September 30, 2009	$ 39	$ (91)	$ 44	$ (2,048)

(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.

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.

	September 30, 2010		December 31, 2009	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Long-term debt	$ 11,409	$ 12,295	$ 12,226	$ 12,824
Convertible preferred stock	$ 3,065	$ 2,994	$ 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 (parent) on a stand-alone, unconsolidated basis, and its combined guarantor and combined non-guarantor subsidiaries as of September 30, 2010 and December 31, 2009 and for the three and nine months ended September 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 SEPTEMBER 30, 2010

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries ($ in millions)	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$	$ 587	$ 22	$	$ 609
Other	3	2,549	139	(27)	2,664
Total Current Assets	3	3,136	161	(27)	3,273
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full-cost accounting		24,649	216		24,865
Other property and equipment, net		3,029	1,586		4,615
Total Property and Equipment		27,678	1,802		29,480
Other assets	193	715	672		1,580
Investments in subsidiaries and intercompany advance	1,356	121		(1,477)	
TOTAL ASSETS	$ 1,552	$ 31,650	$ 2,635	$ (1,504)	$ 34,333
CURRENT LIABILITIES:					
Current liabilities	$ 226	$ 3,816	$ 110	$ (29)	$ 4,123
Intercompany payable (receivable) from parent	(23,340)	21,214	2,145	(19)	
Total Current Liabilities	(23,114)	25,030	2,255	(48)	4,123

LONG-TERM LIABILITIES:									
Long-term debt, net		8,958		2,237		250				11,445
Deferred income tax liabilities		392		1,418		8		21		1,839
Other liabilities		43		1,609		1				1,653
Total Long-Term Liabilities		9,393		5,264		259		21		14,937
EQUITY:										
Chesapeake stockholders equity		15,273		1,356		121		(1,477)		15,273
Noncontrolling interest										
Total Equity		15,273		1,356		121		(1,477)		15,273
TOTAL LIABILITIES AND EQUITY	$	1,552	$	31,650	$	2,635	$	(1,504)	$	34,333

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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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries ($ in millions)	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 SEPTEMBER 30, 2010

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries ($ in millions)	Eliminations	Consolidated
REVENUES:					
Natural gas and oil sales	$	$ 1,639	$	$	$ 1,639
Marketing, gathering and compression sales		856	69	(42)	883
Service operations revenue		59			59
Total Revenues		2,554	69	(42)	2,581
OPERATING COSTS:					
Production expenses		231			231
Production taxes		34			34
General and administrative expenses	2	113	10		125
Marketing, gathering and compression expenses		838	37	(24)	851
Service operations expense		52			52
Natural gas and oil depreciation, depletion and amortization		378			378
Depreciation and amortization of other assets		43	13		56
Impairment or loss on sale of property and equipment		3	34		37
Total Operating Costs	2	1,692	94	(24)	1,764
INCOME (LOSS) FROM OPERATIONS	(2)	862	(25)	(18)	817
OTHER INCOME (EXPENSE):					
Interest (expense) income	(153)	(16)	(1)	167	(3)
Loss on redemptions or exchanges of Chesapeake debt	(59)				(59)
Impairment of investments		(16)			(16)
Other income (expense)	167	52	116	(167)	168
Equity in net earnings of subsidiary	587	44		(631)	
Total Other Income (Expense)	542	64	115	(631)	90
INCOME (LOSS) BEFORE INCOME TAXES	540	926	90	(649)	907
INCOME TAX EXPENSE (BENEFIT)	(18)	339	35	(7)	349
NET INCOME (LOSS)	558	587	55	(642)	558
Net income (loss) attributable to noncontrolling interest					

NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$	558	$	587	$	55	$	(642)	$	558

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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 SEPTEMBER 30, 2009

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			($ in millions)		
REVENUES:					
Natural gas and oil sales	$	$ 1,187	$	$	$ 1,187
Marketing, gathering and compression sales		504	126	(55)	575
Service operations revenue		49			49
Total Revenues		1,740	126	(55)	1,811
OPERATING COSTS:					
Production expenses		218			218
Production taxes		25			25
General and administrative expenses		86	9		95
Marketing, gathering and compression expenses		497	54	(5)	546
Service operations expense		49			49
Natural gas and oil depreciation, depletion and amortization		295			295
Depreciation and amortization of other assets	1	36	25		62
Loss on sale of other property and equipment			124		124
Total Operating Costs	1	1,206	212	(5)	1,414
INCOME (LOSS) FROM OPERATIONS	(1)	534	(86)	(50)	397
OTHER INCOME (EXPENSE):					
Interest (expense) income	(161)	(57)		175	(43)
Loss on redemptions or exchanges of Chesapeake debt	(17)				(17)
Other income (expense)	175	(24)	(6)	(175)	(30)
Equity in net earnings of subsidiary	194	(89)		(105)	
Total Other Income (Expense)	191	(170)	(6)	(105)	(90)
INCOME (LOSS) BEFORE INCOME TAXES	190	364	(92)	(155)	307
INCOME TAX EXPENSE (BENEFIT)	(2)	170	(34)	(19)	115

NET INCOME (LOSS)	192	194	(58)	(136)	192
Net income (loss) attributable to noncontrolling interest					
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 192	$ 194	$ (58)	$ (136)	$ 192

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

NINE MONTHS ENDED SEPTEMBER 30, 2010

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			($ in millions)		
REVENUES:					
Natural gas and oil sales	$	$ 4,698	$	$	$ 4,698
Marketing, gathering and compression sales		2,437	179	(96)	2,520
Service operations revenue		173			173
Total Revenues		7,308	179	(96)	7,391
OPERATING COSTS:					
Production expenses		652			652
Production taxes		119			119
General and administrative expenses	2	315	23		340
Marketing, gathering and compression expenses		2,383	90	(44)	2,429
Service operations expense		154			154
Natural gas and oil depreciation, depletion and amortization		1,025			1,025
Depreciation and amortization of other assets		124	35		159
Impairment or loss on sale of property and equipment		3	34		37
Total Operating Costs	2	4,775	182	(44)	4,915
INCOME (LOSS) FROM OPERATIONS	(2)	2,533	(3)	(52)	2,476
OTHER INCOME (EXPENSE):					
Interest (expense) income	(451)	(107)	(3)	549	(12)
Loss on redemptions or exchanges of Chesapeake debt	(130)				(130)
Impairment of investments		(16)			(16)
Other income (expense)	549	52	150	(549)	202
Equity in net earnings of subsidiary	1,571	57		(1,628)	
Total Other Income (Expense)	1,539	(14)	147	(1,628)	44
	1,537	2,519	144	(1,680)	2,520

INCOME (LOSS) BEFORE INCOME TAXES					
INCOME TAX EXPENSE (BENEFIT)	(13)	948	55	(20)	970
NET INCOME (LOSS)	1,550	1,571	89	(1,660)	1,550
Net income (loss) attributable to noncontrolling interest					
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ 1,550	$ 1,571	$ 89	$ (1,660)	$ 1,550

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

NINE MONTHS ENDED SEPTEMBER 30, 2009

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			($ in millions)		
REVENUES:					
Natural gas and oil sales	$	$ 3,681	$	$	$ 3,681
Marketing, gathering and compression sales		1,461	354	(155)	1,660
Service operations revenue		139			139
Total Revenues		5,281	354	(155)	5,480
OPERATING COSTS:					
Production expenses		670			670
Production taxes		71			71
General and administrative expenses		239	20		259
Marketing, gathering and compression expenses		1,436	148	(15)	1,569
Service operations expense		136			136
Natural gas and oil depreciation, depletion and amortization		1,037			1,037
Depreciation and amortization of other assets		110	67		177
Impairment of natural gas and oil properties		9,600			9,600
Impairment or loss on sale of other property and equipment		35	124		159
Restructuring costs		34			34
Total Operating Costs		13,368	359	(15)	13,712
INCOME (LOSS) FROM OPERATIONS		(8,087)	(5)	(140)	(8,232)
OTHER INCOME (EXPENSE):					
Interest (expense) income	(447)	(112)	(5)	512	(52)
Loss on redemptions or exchanges of Chesapeake debt	(19)				(19)
Impairment of investments		(148)	(14)		(162)
Other income (expense)	512	(21)	(4)	(512)	(25)
Equity in net earnings of subsidiary	(5,335)	(105)		5,440	
Total Other Income (Expense)	(5,289)	(386)	(23)	5,440	(258)
	(5,289)	(8,473)	(28)	5,300	(8,490)

INCOME (LOSS) BEFORE INCOME TAXES					
INCOME TAX EXPENSE (BENEFIT)	17	(3,138)	(11)	(52)	(3,184)
NET INCOME (LOSS)	(5,306)	(5,335)	(17)	5,352	(5,306)
Net income (loss) attributable to noncontrolling interest					
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$ (5,306)	$ (5,335)	$ (17)	$ 5,352	$ (5,306)

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

NINE MONTHS ENDED SEPTEMBER 30, 2010

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 3,774	$ 197	$	$ 3,971
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(7,723)	(212)		(7,935)
Additions to other property and equipment		(412)	(556)		(968)
Proceeds from divestitures of natural gas and oil properties		3,107			3,107
Other investing activities			131		131
Cash used in investing activities		(5,028)	(637)		(5,665)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		10,076	382		10,458
Payments on credit facilities borrowings		(9,736)	(127)		(9,863)
Proceeds from preferred stock, net of offering costs	2,562				2,562
Proceeds from issuance of senior notes, net of offering costs	1,967				1,967
Cash paid to redeem Chesapeake debt	(3,434)				(3,434)
Other financing activities	(243)	567	(18)		306
Intercompany advances, net	(852)	641	211		
Cash provided by (used in) financing activities		1,548	448		1,996
Net increase (decrease) in cash and cash equivalents		294	8		302
Cash and cash equivalents, beginning of period		293	14		307
Cash and cash equivalents, end of period	$	$ 587	$ 22	$	$ 609

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

NINE MONTHS ENDED SEPTEMBER 30, 2009

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
			($ in millions)		
CASH FLOWS FROM OPERATING ACTIVITIES	$	$ 3,075	$ 56	$	$ 3,131
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to natural gas and oil properties		(4,138)			(4,138)
Additions to other property and equipment		(661)	(701)		(1,362)
Proceeds from divestitures of natural gas and oil properties		1,729			1,729
Other investing activities		78	39		117
Cash used in investing activities		(2,992)	(662)		(3,654)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings		4,894	669		5,563
Payments on credit facilities borrowings		(6,749)	(1,117)		(7,866)
Proceeds from issuance of senior notes, net of offering costs	1,346				1,346
Proceeds from sales of noncontrolling interest in midstream joint venture			588		588
Other financing activities	(153)	(167)	(17)		(337)
Intercompany advances, net	(1,193)	554	639		
Cash provided by (used in) financing activities		(1,468)	762		(706)
Net increase (decrease) in cash and cash equivalents		(1,385)	156		(1,229)
Cash and cash equivalents, beginning of period		1,749			1,749
Cash and cash equivalents, end of period	$	$ 364	$ 156	$	$ 520

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Recently Issued and Proposed Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which we reviewed 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.

14. Subsequent Events

On October 10, 2010, we entered into an agreement whereby a wholly owned U.S. subsidiary of CNOOC Limited (CNOOC) agreed to purchase a 33.3% undivided interest in 600,000 net oil and natural gas leasehold acres we hold in the Eagle Ford Shale in South Texas. The consideration for the sale will be approximately $1.08 billion in cash at closing. In addition, CNOOC has agreed to fund 75% of our share of drilling and completion costs in the Eagle Ford Shale project until an additional $1.08 billion has been paid, which we expect to occur by year-end 2012. Closing of the transaction is anticipated in the fourth quarter of 2010.

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

Overview

The following table sets forth certain information regarding the production volumes, natural gas and oil sales, average sales prices received, other operating income and expenses for the three and nine months ended September 30, 2010 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2009 (the Prior Quarter and the Prior Period , respectively):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net Production:				
Natural gas (bcf)	252.8	210.3	689.6	610.3
Oil (mmbbl)	4.5	3.0	12.8	9.1
Natural gas equivalent (bcfe)	280.0	228.5	766.6	664.6
Natural Gas and Oil Sales ($ in millions):				
Natural gas sales	$ 828	$ 596	$ 2,504	$ 1,819
Natural gas derivatives realized gains (losses)	487	675	1,418	1,771
Natural gas derivatives unrealized gains (losses)	315	(275)	534	(398)
Total natural gas sales	1,630	996	4,456	3,192
Oil sales	246	189	739	461
Oil derivatives realized gains (losses)	25	12	66	31
Oil derivatives unrealized gains (losses)	(262)	(10)	(563)	(3)
Total oil sales	9	191	242	489
Total natural gas and oil sales	$ 1,639	$ 1,187	$ 4,698	$ 3,681
Average Sales Price (excluding all gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 3.28	$ 2.84	$ 3.63	$ 2.98
Oil ($ per bbl)	$ 54.25	$ 62.47	$ 57.57	$ 50.97
Natural gas equivalent ($ per mcfe)	$ 3.84	$ 3.44	$ 4.23	$ 3.43
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Natural gas ($ per mcf)	$ 5.20	$ 6.04	$ 5.69	$ 5.88
Oil ($ per bbl)	$ 59.81	$ 66.42	$ 62.75	$ 54.37
Natural gas equivalent ($ per mcfe)	$ 5.67	$ 6.44	$ 6.17	$ 6.14

Other Operating Income[a] ($ in millions):				
Marketing, gathering and compression	$ 32	$ 29	$ 91	$ 91
Service operations	$ 7	$	$ 19	$ 3
Other Operating Income[a] ($ per mcfe):				
Marketing, gathering and compression	$ 0.12	$ 0.13	$ 0.12	$ 0.14
Service operations	$ 0.03	$	$ 0.03	$
Expenses ($ per mcfe):				
Production expenses	$ 0.83	$ 0.96	$ 0.85	$ 1.01
Production taxes	$ 0.12	$ 0.11	$ 0.16	$ 0.11
General and administrative expenses	$ 0.45	$ 0.42	$ 0.44	$ 0.39
Natural gas and oil depreciation, depletion and amortization	$ 1.35	$ 1.29	$ 1.34	$ 1.56
Depreciation and amortization of other assets	$ 0.20	$ 0.27	$ 0.21	$ 0.27
Interest expense[b]	$	$ 0.28	$ 0.11	$ 0.24
Interest Expense ($ in millions):				
Interest expense[c]	$ 3	$ 70	$ 93	$ 177
Interest rate derivatives realized (gains) losses	(2)	(7)	(6)	(19)
Interest rate derivatives unrealized (gains) losses	2	(20)	(75)	(106)
Total interest expense	$ 3	$ 43	$ 12	$ 52
Net Wells Drilled	281	224	794	700
Net Producing Wells as of the End of the Period	22,445	22,749	22,445	22,749

(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.

(c) Net of amounts capitalized.

We are the second largest producer of natural gas and a Top 20 producer of oil and natural gas liquids in the U.S. We own interests in approximately 45,100 producing natural gas and oil wells that are currently producing approximately 2.8 bcfe per day, 88% 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 liquids-rich plays of the Granite Wash in western Oklahoma and the Texas Panhandle regions, the Niobrara Shale and Frontier Sand plays of the Powder River and DJ Basins of Wyoming and Colorado, as well as various other liquids-rich 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 U.S. 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 31% 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 65% 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, Tonkawa, Cleveland and Mississippian plays of the Anadarko Basin; the Avalon, Bone Spring and Wolfcamp plays of the Permian Basin; and the Eagle Ford and Niobrara Shales. The company now owns approximately 3.1 million net leasehold acres in unconventional liquids-rich plays.

Chesapeake began 2010 with estimated proved reserves of 14.254 tcfe and ended the Current Period with 16.223 tcfe, an increase of 1.969 tcfe, or 14%. During the Current Period, we replaced 767 bcfe of production with an internally estimated 2.736 tcfe of new proved reserves, for a reserve replacement rate of 357%. The Current Period s proved reserve movement included 3.355 tcfe of extensions, 611 bcfe of positive performance revisions and 219 bcfe of positive revisions resulting from an increase in the twelve-month trailing average natural gas and oil prices between December 31, 2009 and September 30, 2010. During the Current Period, we acquired 50 bcfe of estimated proved reserves and divested 1.499 tcfe of estimated proved reserves.

During the Current Period, Chesapeake continued the industry s most active drilling program, drilling 1,041 gross operated wells (676 net wells with an average working interest of 65%) and participating in another 911 gross wells operated by other companies (118 net wells with an average working interest of 13%). The company s drilling success rate was 99% for company-operated wells and 98% for non-operated wells. Also during the Current Period, we invested $3.308 billion in operated wells (using an average of 127 operated rigs) and $545 million in non-operated wells (using an average of 111 non-operated rigs) for total drilling, completing and equipping costs of $3.853 billion (net of carries).

Our total Current Quarter production was 280.0 bcfe, comprised of 252.8 bcf of natural gas (90% on a natural gas equivalent basis) and 4.5 mmbbls of oil and natural gas liquids (10% on a natural gas equivalent basis). Daily production for the Current Quarter averaged 3.043 bcfe, an increase of 560 mmcfe, or 23%, over the 2.483 bcfe produced per day in the Prior Quarter.

Our total Current Period production was 766.6 bcfe, comprised of 689.6 bcf of natural gas (90% on a natural gas equivalent basis) and 12.8 mmbbls of oil and natural gas liquids (10% on a natural gas equivalent basis). Daily production for the Current Period averaged 2.808 bcfe, an increase of 373 mmcfe, or 15%, over the 2.435 bcfe produced per day in the Prior Period.

Since 2000, Chesapeake has built the largest combined inventories of onshore leasehold (13.8 million net acres) and 3-D seismic (27.4 million acres) in the U.S. and the largest inventory of U.S. natural gas shale play leasehold (2.8 million net acres). We now own 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 140 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

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

Debt Reduction

During the Current Period, 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 $1.934 billion in principal amount of four series of our outstanding senior notes. Additionally, through tender offers followed by redemptions, we purchased $1.5 billion aggregate principal amount of three additional series of senior notes. We funded the purchase of the notes tendered and redeemed with proceeds from a $2.0 billion public offering of two series of senior notes. Upon the completion of the redemptions and tender offers in the Current Quarter, we retired all series of our outstanding senior notes that were issued under our more restrictive indentures. Excess funds from our offerings were used to repay borrowings outstanding under our corporate revolving bank credit facility.

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, geo-scientific, 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 we expect to increase our liquids production by 80% and 60% in 2011 and 2012, respectively.

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 and Avalon 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 because we could lose our competitive advantage in those areas. 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.

Asset Sales

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. (Total), paid $800 million in cash at closing (plus $78 million of drilling and completion carries due from the effective date of the transaction to the closing date) and agreed to pay a total of $1.45 billion in drilling and completion carries over time by funding 60% of our share of future drilling and completion expenditures. The following table provides information about our remaining joint venture drilling and completion carries as of September 30, 2010:

Shale Play	Joint Venture Partner	Joint Venture Date	Carries Remaining ($ in millions)
Marcellus	Statoil	November 2008	$ 1,566
Barnett	Total	January 2010	1,023
			$ 2,589

The drilling and completion carries in our 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, our drilling and completion costs included the benefit of approximately $745 million and

$959 million, respectively, of joint venture drilling and completion carries. Our drilling and completion costs for the remainder of 2010 and in 2011, 2012 and 2013 will continue to be partially offset by the use of our remaining drilling and completion carries associated with our joint ventures in the Barnett and Marcellus Shales.

In October 2010, we entered into an industry cooperation agreement whereby a wholly owned subsidiary of CNOOC Limited (CNOOC) agreed to purchase a 33.3% undivided interest in 600,000 net natural gas and oil leasehold acres we hold in the Eagle Ford Shale in South Texas. The consideration for the sale will be approximately $1.08 billion in cash at closing. In addition, CNOOC has agreed to fund 75% of our share of drilling and completion costs in the Eagle Ford Shale project until an additional $1.08 billion has been paid, which we expect to occur by year-end 2012. Closing of the transaction is anticipated in the fourth quarter of 2010.

We completed three volumetric production payments (VPPs) in the Current Period, bringing our total of such transactions to eight. The company s sixth VPP was completed in February 2010 for proceeds of approximately $180 million, or $3.95 per mcfe. In June 2010, we completed our seventh VPP for proceeds of approximately $335 million, or $8.73 per mcfe. Most recently, in September 2010, we completed our eighth VPP for proceeds of approximately $1.15 billion, or $2.93 per mcfe.

In the Current Period, 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

Total, Statoil and Plains, we sold an interest in additional leasehold in the Barnett, Marcellus and Haynesville Shale plays for proceeds of approximately $395 million that had an estimated cost basis of $195 million. The cash proceeds from these transactions are reflected as a reduction of natural gas and oil properties with no gain or loss recognized.

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

On August 3, 2010, Chesapeake Midstream Partners, L.P. (NYSE: CHKM), which we and Global Infrastructure Partners (GIP) formed to own, operate, develop and acquire midstream assets, completed an initial public offering of 24,437,500 common units (including 3,187,500 common units issued pursuant to the exercise of the underwriters over-allotment option on August 3, 2010) representing limited partner interests and received gross offering proceeds of approximately $513 million at an initial offering price of $21.00 per unit less approximately $38 million for underwriting discounts and commissions, structuring fees and offering expenses. Pursuant to the terms of our contribution agreement with GIP, CHKM distributed the approximate $62 million of net proceeds from the exercise of the over-allotment option to GIP on August 3, 2010. 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 is continuing 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 98.0% interest in CHKM and the general partner, which is owned and controlled 50/50 by Chesapeake and GIP, has a 2.0% interest in CHKM.

On October 26, 2010, CHKM declared its first distribution for the period from the date of the closing of its initial public offering on August 3, 2010 through September 30, 2010. It corresponds to a full quarterly distribution of $0.3375 per unit, or $1.35 per unit on an annualized basis. At this distribution level, Chesapeake would receive quarterly distributions of approximately $20 million in respect of its limited partner and general partner interests. In the future, we plan to enter into drop down transactions with CHKM for some of the assets owned by our wholly owned midstream subsidiary, Chesapeake Midstream Development, L.P., whose gas gathering operations are located primarily in the Haynesville, Fayetteville, Marcellus and Eagle Ford Shales.

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 and completion carries, are $4.8 - $5.0 billion in 2010, 2011 and 2012. We are also continuing to build an industry-leading unconventional liquids portfolio through new play identification systems and subsequent leasing programs. As of September 30, 2010, we had made commitments to acquire additional leasehold in various transactions during the next twelve months for approximately $1.7 billion, including the acquisition of a significant additional position in the Appalachian Basin from privately-held Anschutz Corporation. In this transaction, which is scheduled to close in November 2010, we have agreed to acquire approximately 500,000 net acres of Appalachian Basin leasehold and option rights for approximately $850 million. Approximately 25% of these assets will be immediately marketed for resale after closing while the remainder of the assets will be combined with our leasehold in a play in which the company expects to execute a new industry joint venture in the first half of 2011. As with all of Chesapeake s leasehold acquisitions in new plays, the company s goal remains to acquire an industry-leading leasehold position in a new play and then bring in a minority industry partner to help de-risk the play and to provide reimbursement of all or most of Chesapeake s leasehold costs in the new play.

Management believes that our planned leasehold and development joint ventures and various asset monetization programs benefit the company in several ways, including the creation of significant net asset value, improvement of our asset base through increasing the percentage of our assets that are oil and natural gas liquids, the reduction of financial risk, the reduction of our DD&A rate and the increase in our profitability per unit of production, thereby increasing our returns on capital and advancing future value creation to the present.

During the fourth quarter of 2010 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. Additionally, we anticipate closing two additional VPP transactions, certain midstream asset sales and various other smaller planned sales. In total, Chesapeake is targeting to receive proceeds of approximately $1.3 - $1.5 billion in the fourth quarter of 2010 and approximately $3.0 - $3.5 billion in 2011 from asset sales. 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.

We plan to fund our 2010 and 2011 budgeted exploration and development capital expenditures, together with other capital expenditure requirements, from a combination of cash flow from operations, credit facility borrowings and asset monetizations.

In anticipation of the maturity of our existing credit facility in November 2012, Chesapeake is in the process of syndicating a new $4.0 billion senior secured revolving bank credit facility. The new facility will replace the company s existing $3.5 billion facility in its entirety and have a term of five years. The syndication of the new facility is anticipated to be completed in November 2010.

Liquidity and Capital Resources

Sources and Uses of Funds

Cash flow from operations is a significant source of liquidity used to fund capital expenditures, pay dividends and repay debt. Cash provided by operating activities was $3.971 billion in the Current Period compared to $3.131 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 53% and 28% of our expected remaining natural gas and oil production in 2010 at an average price of $7.66 per mcf and $89.94 per bbl, respectively. Additionally, we have hedged through swaps 60% and 3% of our expected natural gas and oil production in 2011 at an average price of $6.44 per mcf and $104.75 per bbl, respectively. Our natural gas and oil hedges as of September 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. We use the credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $10.458 billion and repaid $9.863 billion in the Current Period, and we borrowed $5.563 billion and repaid $7.866 billion in the Prior Period from our revolving credit facilities. A significant 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 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 August 17, 2010, we completed a public offering of $2.0 billion aggregate principal amount of senior notes. The offering consisted of $600 million of 6.875% Senior Notes due 2018 and $1.4 billion of 6.625% Senior Notes due 2020. Both series were priced at par. Net proceeds received were $1.967 billion.

In the Current Period and Prior Period, we received $436 million and $19 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 $142 million and $135 million in the Current Period and the Prior Period, respectively. We paid dividends on our preferred stock of $49 million in the Current Period and $18 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 these redemptions, we recognized a loss of $69 million in the Current Period.

On July 22, 2010, we redeemed 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. Associated with the redemption, we recognized a loss of $19 million in the Current Period.

On August 30, 2010, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. On September 16, 2010, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 million in the Current Period.

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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 September 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 ($675 million at September 30, 2010) and exploration and production companies which own interests in properties we operate ($635 million at September 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 and the Current Period, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables. During the Prior Period, we recognized $13 million of bad debt expense related to potentially uncollectible receivables.

Investing Activities

Cash used in investing activities increased to $5.665 billion during the Current Period, compared to $3.654 billion during the Prior Period. The majority of our $2.011 billion increase in investing activities was the result of our increased acquisition of unproved properties and exploration and development activities. The following table shows our cash used in (provided by) investing activities during these periods:

	Nine Months Ended September 30,	
	2010	2009
	($ in millions)	
Natural Gas and Oil Investing Activities:		
Acquisitions of natural gas and oil proved properties	$ 139	$ 17
Acquisition of leasehold and unproved properties	3,575	890
Exploration and development of natural gas and oil properties	3,576	2,647
Geological and geophysical costs[(a)]	142	143
Interest capitalized on unproved properties	503	441
Proceeds from divestitures of proved and unproved properties	(3,107)	(1,729)
Deposits for acquisitions	95	
Total natural gas and oil investing activities	4,923	2,409
Other Investing Activities:		
Additions to other property and equipment	968	1,362
Additions to investments	113	40
Proceeds from sales of other assets	(328)	(157)
Other	(11)	
Total other investing activities	742	1,245
Total cash used in investing activities	$ 5,665	$ 3,654

(a) Including related capitalized interest.

In the Prior Period, pursuant to an acquisition shelf registration statement, we issued 24,822,832 shares of common stock valued at $429 million for the purchase of proved and unproved properties.

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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	$ 300
Maturity date	November 2012	July 2015
Facility structure	Senior secured revolving	Senior secured revolving
Amount outstanding as of September 30, 2010	$ 2,237	$ 250
Letters of credit outstanding as of September 30, 2010	$ 13	$

(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.

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, neither of our credit facilities contains 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 and require us to maintain an indebtedness to total capitalization ratio and an indebtedness to EBITDA ratio, in each case as defined in the agreement. We were in compliance with all covenants under the agreement at September 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 $50 million or more, 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 certain of our other wholly owned subsidiaries.

Midstream Credit Facility

Our $300 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 1.75% to 2.25% per annum according to the most recent leverage ratio described below or (ii) the LIBOR plus a margin that varies from 2.75% to 3.25% per annum according to the most recent leverage ratio. The unused portion of the facility is subject to a commitment fee of 0.50% per annum according to the most recent leverage ratio. 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 agreement requires maintenance of a leverage ratio based on the ratio of indebtedness to EBITDA and an interest coverage ratio based on the ratio of EBITDA to interest expense, in each case as defined in the agreement. The leverage ratio increases during any three-quarter period, beginning in the quarter in which CMD makes a material disposition of assets to our master limited partnership midstream affiliate, Chesapeake Midstream Partners, L.P. We were in compliance with all covenants under the agreement at September 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 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 September 30, 2010, we had hedged a total of 2.3 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.

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities discussed above, as of September 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
9.5% senior notes due 2015		1,425
6.25% euro-denominated senior notes due 2017[(a)]		816
6.5% senior notes due 2017		1,100
6.875% senior notes due 2018		600
7.25% senior notes due 2018		800
6.625% senior notes due 2020		1,400
6.875% senior notes due 2020		500
2.75% contingent convertible senior notes due 2035[(b)]		451
2.5% contingent convertible senior notes due 2037[(b)]		1,378
2.25% contingent convertible senior notes due 2038[(b)]		752
Discount on senior notes[(c)]		(800)
Interest rate derivatives[(d)]		36
	$	8,958

(a) The principal amount shown is based on the dollar/euro exchange rate of $1.3601 to 1.00 as of September 30, 2010. See Note 2 of our condensed consolidated financial statements included in this report for information on our related foreign currency derivatives.

(b) 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 third 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 fourth quarter of 2010 under this provision. The

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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

(c) Included in this discount is $731 million at September 30, 2010 associated with the equity component of our contingent convertible senior notes.

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

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. Our senior notes 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.

Other Contractual Obligations

Chesapeake has various financial obligations which are not recorded as liabilities in its condensed consolidated balance sheet at September 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 leasehold purchase commitments. These commitments are discussed in Note 3 of our condensed consolidated financial statements included in this report.

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

General. For the Current Quarter, Chesapeake had net income of $558 million, or $0.75 per diluted common share, on total revenues of $2.581 billion. This compares to net income of $192 million, or $0.30 per diluted common share, on total revenues of $1.811 billion during the Prior Quarter.

Natural Gas and Oil Sales. During the Current Quarter, natural gas and oil sales were $1.639 billion compared to $1.187 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 280.0 bcfe at a weighted average price of $5.67 per mcfe, compared to 228.5 bcfe produced in the Prior Quarter at a weighted average price of $6.44 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on natural gas and oil derivatives of $53 million and ($285) million in the Current Quarter and the Prior Quarter, respectively). In the Current Quarter, the decrease in prices resulted in a decrease in revenue of $216 million and increased production resulted in a $331 million increase, for a total increase in revenues of $115 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 $5.20, compared to $6.04 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 $59.81 and $66.42 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 $512 million, or $1.83 per mcfe, in the Current Quarter and a net increase of $687 million, or $3.00 per mcfe, in the Prior Quarter.

Changes in natural gas and oil prices have a significant impact on our natural gas and oil revenues and cash 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 a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $5 million and $4 million, respectively, 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 September 30, 2010						
	Natural Gas		Oil/NGLs		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Haynesville Shale	68.3	3.64			68.3	24%	3.64
Barnett Shale	50.9	2.33	0.2	23.94	52.1	19	2.37
Fayetteville Shale	36.1	3.07			36.1	13	3.07
Marcellus Shale	15.7	3.68			15.7	6	3.68
Eagle Ford Shale	0.3	4.55	0.1	74.23	0.9		9.48
Bossier Shale							
Other:							
Mid-Continent	58.4	3.45	3.4	52.42	79.0	28	4.84
Permian and Delaware Basins	10.6	3.84	0.6	70.39	14.2	5	5.98
South Texas/Gulf Coast/ Ark-La-Tex	7.0	4.00	0.1	61.38	7.6	3	4.27
Other Appalachian Basin	5.5	3.22	0.1	45.03	6.1	2	3.63
Total[b]	252.8	3.28	4.5	54.25	280.0	100%	3.84

	Three Months Ended September 30, 2009						
	Natural Gas		Oil/NGLs		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Haynesville Shale	24.0	2.57			24.0	11%	2.57
Barnett Shale	58.6	1.93			58.6	25	1.93
Fayetteville Shale	23.1	2.49			23.1	10	2.49
Marcellus Shale	5.0	3.36			5.0	2	3.36
Eagle Ford Shale							
Bossier Shale							
Other:							
Mid-Continent	67.5	3.53	2.0	62.03	79.5	35	4.57
Permian and Delaware Basins	13.5	3.22	0.8	64.90	18.2	8	5.14
South Texas/Gulf Coast/ Ark-La-Tex	12.5	3.72	0.1	59.28	13.7	6	4.14
Other Appalachian Basin	6.1	3.14	0.1	55.01	6.4	3	3.43
Total[b]	210.3	2.84	3.0	62.47	228.5	100%	3.44

(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 second quarter of 2010 (1.8 bcfe).

Our average daily production of 3.043 bcfe for the Current Quarter consisted of 2.748 bcf of natural gas and 49,272 barrels of oil and natural gas liquids (NGLs). Our Current Quarter production of 280.0 bcfe was comprised of 252.8 bcf (90% on a natural gas equivalent basis) and 4.5 million barrels of oil and NGLs

(10% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 20% and our year-over-year growth rate of oil and NGL (liquids) production was 50%. Our percentage of revenue from liquids in the Current Quarter was 17% of realized natural gas and oil revenue compared to 14% in the Prior Quarter.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression sales and operating expenses consist of third-party revenue and operating expenses related to our midstream operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $883 million in marketing, gathering and compression sales in the Current Quarter, with corresponding marketing, gathering and compression expenses of $851 million, for a net margin before depreciation of $32 million. This compares to sales of $575 million, expenses of $546 million and a net margin before depreciation of $29 million in the Prior Quarter. In the Current Quarter, 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 assets 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 $59 million in service operations revenue in the Current Quarter with corresponding service operations expense of $52 million, for a net margin before depreciation of $7 million. This compares to revenue of $49 million, expenses of $49 million and a net loss before depreciation of a nominal amount in the Prior Quarter.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $231 million in the Current Quarter and $218 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.83 per mcfe in the Current Quarter compared to $0.96 per mcfe in the Prior Quarter. The decrease per mcfe 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 $34 million in the Current Quarter compared to $25 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.12 per mcfe in the Current Quarter compared to $0.11 per mcfe in the Prior Quarter. The $9 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 $0.40 per mcfe (excluding gains or losses on derivatives) and an increase in production of 52 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 and other property, plant and equipment, were $125 million in the Current Quarter and $95 million in the Prior Quarter. The increase in the Current Quarter was the result of the company s continued growth. General and administrative expenses were $0.45 and $0.42 per mcfe for the Current Quarter and Prior Quarter, respectively.

Included in general and administrative expenses is stock-based compensation of $21 million for the Current Quarter and $22 million for the Prior Quarter. Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. 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 stock-based compensation.

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. In addition, we capitalize internal costs that can be identified with the construction of certain of our property, plant and equipment. We capitalized $98 million and $91 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 and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $378 million and $295 million during the Current Quarter and the Prior Quarter, respectively. The $83 million increase is primarily the result of a 22% increase in production from the Prior Quarter compared to the Current Quarter. 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 $1.35 and $1.29 in the Current Quarter and in the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $56 million in the Current Quarter and $62 million in the Prior Quarter. Depreciation and amortization of other assets was $0.20 and $0.27 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 assets 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 and development costs.

Impairment or Loss on Sale of Other Property and Equipment. In the Current Quarter, we recorded a $37 million charge associated with the impairment or loss on sale of other property, plant and equipment. Of this amount, $18 million was related to various sales of other property plant and equipment including the sale of pipe, gas gathering systems and other miscellaneous assets, and an additional $19 million impairment was recorded related to the obsolescence of certain pipe inventory.

In the Prior Quarter, we recorded a $124 million loss associated with the impairment or loss on sale of other property, plant and equipment. An $82 million impairment was related to certain gathering systems contributed to our midstream joint venture, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million midstream revolving bank credit facility that was reduced to $250 million. Also, in the Prior Quarter, we recorded a $38 million loss on the sale of two gathering systems.

Interest Expense. Interest expense decreased to $3 million in the Current Quarter compared to $43 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2010	2009
	($ in millions)	
Interest expense on senior notes	$ 167	$ 195
Interest expense on credit facilities	18	18
Capitalized interest	(185)	(153)
Realized (gain) loss on interest rate derivatives	(2)	(7)
Unrealized (gain) loss on interest rate derivatives	2	(20)
Amortization of loan discount and other	3	10
Total interest expense	$ 3	$ 43
Average long-term borrowings on senior notes	$ 9,632	$ 11,372

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was a nominal amount per mcfe in the Current Quarter compared to $0.28 per mcfe in the Prior Quarter. The decrease in interest expense per mcfe is due primarily to increased production, a decrease in our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased $32 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.

Loss on Redemptions or Exchanges of Chesapeake Debt. During the Current Quarter, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. We recognized a loss of $19 million in the Current Quarter associated with the redemption.

Also during the Current Quarter, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 million in the Current Quarter.

In the Prior Quarter, we privately exchanged approximately $153 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 4,176,671 shares of our common stock valued at approximately $110 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 72% 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 $153 million principal amount of convertible notes exchanged in the Prior Quarter, $96 million was allocated to the debt component of the notes and the remaining $57 million was allocated to the equity conversion feature of the notes 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 a $17 million loss (including $3 million of deferred charges associated with the exchanges).

Impairment of Investments. In the Current Quarter, we recorded impairments of $16 million related to certain other equity investments.

Other Income (Expense). Other income (expense) was $168 million and ($30) million in the Current Quarter and Prior Quarter, respectively. The Current Quarter included a $121 million gain related to the initial public offering by CHKM and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value. The Current Quarter also included $30 million of income related to our equity in net income of certain of our investments, $4 million of interest income and $13 million of miscellaneous income. The Prior Quarter consisted of a $24 million loss related to our equity in net losses of certain of our investments, $1 million of interest income and $7 million of miscellaneous expense.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $349 million in the Current Quarter compared to $115 million in the Prior Quarter. Of the $234 million increase in income tax expense recorded in the Current Quarter, $225 million was the result of the increase in net income before income taxes and $9 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   Nine Months Ended September 30, 2010 vs. September 30, 2009

General. For the Current Period, Chesapeake had net income of $1.550 billion, or $2.24 per diluted common share, on total revenues of $7.391 billion. This compares to a net loss of $5.306 billion, or $8.78 per diluted common share, on total revenues of $5.480 billion during the Prior Period. The Prior Period loss was due to a non-cash impairment of natural gas and oil properties 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 $4.698 billion compared to $3.681 billion in the Prior Period. In the Current Period, Chesapeake produced 766.6 bcfe at a weighted average price of $6.17 per mcfe, compared to 664.6 bcfe produced in the Prior Period at a weighted average price of $6.14 per mcfe (weighted average prices exclude the effect of unrealized losses on natural gas and oil derivatives of ($29) million in the Current Period and ($401) million in the Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $18 million and increased production resulted in a $627 million increase, for a total increase in revenues of $645 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 our successful drilling results.

For the Current Period, we realized an average price per mcf of natural gas of $5.69, compared to $5.88 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 $62.75 and $54.37 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 $1.484 billion, or $1.94 per mcfe, in the Current Period and a net increase of $1.802 billion, or $2.71 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 $69 million and $67 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 $13 million and $12 million, respectively, 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:

	Nine Months Ended September 30, 2010						
	Natural Gas		Oil/NGLs		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Haynesville Shale	159.2	3.75			159.2	21%	3.75
Barnett Shale	148.0	2.60	0.5	29.21	151.0	20	2.64
Fayetteville Shale	100.8	3.35			100.8	13	3.35
Marcellus Shale	34.2	4.20			34.2	5	4.20
Eagle Ford Shale	0.6	4.85	0.2	72.32	1.8		9.41
Bossier Shale							
Other:							
Mid-Continent	172.2	4.26	9.6	55.08	230.0	30	5.49
Permian and Delaware Basins	34.7	4.28	2.1	73.52	47.3	6	6.40
South Texas/Gulf Coast/ Ark-La-Tex	22.4	4.27	0.2	71.29	23.6	3	4.67
Other Appalachian Basin	17.5	3.49	0.2	54.81	18.7	2	3.82
Total[b]	689.6	3.63	12.8	57.57	766.6	100%	4.23

	Nine Months Ended September 30, 2009						
	Natural Gas		Oil/NGLs		Total		
	(Bcf)	($/Mcf)[a]	(Mmbbl)	($/Bbl)[a]	(Bcfe)	%	($/Mcfe)[a]
Big 6 Shales:							
Haynesville Shale	50.6	3.03	0.1	46.00	51.2	8%	3.09
Barnett Shale	175.2	2.07			175.2	26	2.07
Fayetteville Shale	61.8	2.90			61.8	9	2.90
Marcellus Shale	14.7	4.50			14.7	2	4.50
Eagle Ford Shale							
Bossier Shale							
Other:							
Mid-Continent	196.2	3.45	5.9	50.69	231.6	35	4.22
Permian and Delaware Basins	43.2	3.21	2.3	52.33	57.0	9	4.54
South Texas/Gulf Coast/ Ark-La-Tex	52.2	3.68	0.6	49.75	55.8	8	3.96
Other Appalachian Basin	16.4	2.96	0.2	49.67	17.3	3	3.23
Total[b]	610.3	2.98	9.1	50.97	664.6	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 Period (1.8 bcfe).

Our average daily production of 2.808 bcfe for the Current Period consisted of 2.526 bcf of natural gas and 47,007 bbls of oil and NGLs. Our Current Period production of 766.6 bcfe was comprised of 689.6 bcf (90% on a natural gas equivalent basis) and 12.8 mmbbls (10% on a natural gas equivalent basis). Our year-over-year growth rate of natural gas production was 13% and our year-over-year growth rate of oil and NGL (liquids) production was 42%. Our percentage of revenue from liquids in the Current Period was 17% of realized natural gas and oil revenue compared to 12% in the Prior Period.

Marketing, Gathering and Compression Sales and Operating Expenses. Marketing, gathering and compression sales and operating expenses consist of third-party revenue and operating expenses related to our midstream operations. Marketing, gathering and compression activities are performed by Chesapeake substantially for owners in Chesapeake-operated wells. Chesapeake realized $2.520 billion in marketing, gathering and compression sales in the Current Period, with corresponding marketing, gathering and compression expenses of $2.429 billion, for a net margin before depreciation of $91 million. This compares to sales of $1.660 billion, expenses of $1.569 billion and a net margin before depreciation of $91 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 assets 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 $173 million in service operations revenue in the Current Period with corresponding service operations expense of $154 million, for a net margin before depreciation of $19 million. This compares to revenue of $139 million, expenses of $136 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 $652 million in the Current Period compared to $670 million in the Prior Period. On a unit-of-production basis, production expenses were $0.85 per mcfe in the Current Period compared to $1.01 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 $119 million in the Current Period compared to $71 million in the Prior Period. On a unit-of-production basis, production taxes were $0.16 per mcfe in the Current Period compared to $0.11 per mcfe in the Prior Period. The $48 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 $0.80 per mcfe (excluding gains or losses on derivatives) and an increase in production of 102 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 and other property, plant and equipment, were $340 million in the Current Period and $259 million in the Prior Period. The increase in the Current Period was the result of the company s continued growth. General and administrative expenses were $0.44 and $0.39 per mcfe for the Current Period and Prior Period, respectively.

Included in general and administrative expenses is stock-based compensation of $63 million for the Current Period and $60 million for the Prior Period. Our stock-based compensation for employees and non-employee directors is in the form of restricted stock and helps offset the fact that we do not have a pension plan. 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 stock-based compensation.

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. In addition, we capitalize internal costs that can be identified with the construction of certain of our property, plant and equipment. We capitalized $287 million and $282 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 and the construction of our property, plant and equipment.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $1.025 billion and $1.037 billion during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $1.34 and $1.56 in the Current Period and in the Prior Period, respectively. The $0.22 decrease in the average 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 2008 and 2009.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $159 million in the Current Period and $177 million in the Prior Period. Depreciation and amortization of other assets was $0.21 and $0.27 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 assets 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

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used to drill our wells, a substantial portion of the depreciation is capitalized in natural gas and oil properties as exploration and development costs.

Impairment of Natural Gas and Oil Properties. 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.

Impairment or Loss on Sale of Other Property and Equipment. In the Current Period, we recorded a $37 million charge associated with the impairment or loss on sale of other property, plant and equipment. An $18 million loss was related to various sales of other property, plant and equipment including the sale of pipe, gas gathering systems and other miscellaneous assets, and an additional $19 million impairment was recorded related to the obsolescence of certain pipe inventory.

In the Prior Period, we recorded a $159 million loss associated with the impairment or loss on sale of other property, plant and equipment. An $82 million impairment was related to certain gathering systems contributed to our midstream joint venture, as well as a $4 million impairment of debt issuance costs associated with the portion of our $460 million midstream revolving bank credit facility that was reduced to $250 million. Also in the Prior Period, we recognized a $22 million charge in the Prior Period for a deposit on canceled contracts that were not refunded. Additionally, we recorded a $38 million loss on the sale of two gathering systems. Finally, we recognized $13 million of bad debt expense related to potentially uncollectible receivables.

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 Expens*e. Interest expense decreased to $12 million in the Current Period from $52 million in the Prior Period as follows:

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
	($ in millions)	
Interest expense on senior notes	$ 550	$ 572
Interest expense on credit facilities	42	47
Capitalized interest	(525)	(467)
Realized (gain) loss on interest rate derivatives	(6)	(19)
Unrealized (gain) loss on interest rate derivatives	(75)	(106)
Amortization of loan discount and other	26	25
Total interest expense	$ 12	$ 52
Average long-term borrowings on senior notes	$ 10,538	$ 11,172

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.11 per mcfe in the Current Period compared to $0.24 per mcfe in the Prior Period. The decrease in interest expense per mcfe is due primarily to increased production, a decrease in our senior notes outstanding and an increase in capitalized interest. Capitalized interest increased $58 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.

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. Also during the Current Period, we redeemed in whole for a redemption price of approximately $619 million, plus accrued interest, all $600 million in principal amount of our 6.375% Senior Notes due 2015. We recognized a loss of $19 million in the Current Period associated with the redemption.

Additionally during the Current Period, we completed tender offers to purchase for cash $245 million of 7.00% Senior Notes due 2014, $567 million of 6.625% Senior Notes due 2016 and $582 million of 6.25% Senior Notes due 2018. Following the completion of these tender offers, we redeemed the remaining $55 million of 7.00% Senior Notes due 2014, $33 million of 6.625% Senior Notes due 2016 and $18 million of 6.25% Senior Notes due 2018 based on the redemption provisions in the indentures. Associated with the tender offers and redemptions, we recognized a loss of $40 million in the Current Period.

Finally, 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 of the notes and the remaining $4 million was allocated to the equity conversion feature of the notes 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 $238 million in aggregate principal amount of our 2.25% Contingent Convertible Senior Notes due 2038 for an aggregate of 6,707,321 shares of our common stock valued at approximately $164 million. Through these transactions, we were able to retire this debt for common stock valued at approximately 70% of the face value of the notes. Of the $238 million principal amount of convertible notes exchanged in the Prior Period, $148 million was allocated to the debt component and the remaining $90 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 a $19 million loss (including $3 million of deferred charges associated with the exchanges).

Impairment of Investments. In the Current Period, we recorded a $16 million impairment of certain other equity investments. In the Prior Period, we recorded a $162 million impairment of certain investments. Each of our investees was 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.

Other Income (Expense). Other income (expense) was $202 million and ($25) million in the Current Period and Prior Period, respectively. The Current Period included a $121 million gain related to the initial public offering by CHKM and a private offering of common stock by Chaparral Energy, Inc., which represented our proportionate share of the excess of offering proceeds over our carrying value. The Current Period also included $69 million of income related to our equity in net income of certain of our investments, $7 million of interest income and $5 million of miscellaneous income. The Prior Period consisted of a $32 million loss related to our equity in net losses of certain of our investments, $6 million of interest income and $1 million of miscellaneous expense.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $970 million in the Current Period, compared to an income tax benefit of $3.184 billion in the Prior Period. Of the $4.154 billion increase in income tax expense recorded in the Current Period, $4.129 billion was the result of the increase in net income before income taxes and $25 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;

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;

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.

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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, collars and options, 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.

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 2016 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. In the Current Quarter we took advantage of the lower strip prices by restructuring a portion of our call options. We restructured certain natural gas and oil calls by lowering the strike price on call options sold for 2012 through 2015 and used the value to buy back call options for the same periods. This reduced our collateral requirements under our hedging facility and increased our capacity to hedge additional volumes.

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As of September 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 September 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 September 30, 2010:

		Weighted Average Price				Cash Flow	Fair
	Volume	Fixed	Put	Call	Differential	Hedge	Value
Natural Gas:	(bbtu)		(per mmbtu)				($ in millions)
Swaps:							
Q4 2010	69,588	$ 7.54	$	$	$	Yes	$ 250
Q1 2011	34,922	6.49				Yes	77
Q2 2011	30,030	6.15				Yes	56
Q3 2011	30,360	6.15				Yes	52
Q4 2011	30,360	6.15				Yes	41
Other Swaps[(a)]:							
Q4 2010	45,720	7.84				No	178
Q1 2011	90,660	7.30				No	197
Q2 2011	88,050	7.20				No	181
Q3 2011	89,100	7.21				No	172
Q4 2011	89,100	7.24				No	148
2012	18,300	6.50				No	26
Other Collars:							
Q4 2010	3,680		7.60	11.75		No	13
Q1 2011	1,800		7.70	11.50		No	6
Q2 2011	1,820		7.70	11.50		No	6
Q3 2011	1,840		7.70	11.50		No	6
Q4 2011	1,840		7.70	11.50		No	6
Call Options:							
Q4 2010	22,570			10.08		No	
Q1 2011	5,175			8.00		No	
Q2 2011	5,233			8.00		No	
Q3 2011	5,290			8.00		No	
Q4 2011	5,290			8.00		No	
2012	161,077			6.54		No	(42)
2013	478,191			6.88		No	(154)
2014 2020	650,793			7.49		No	(285)
Put Options:							
Q4 2010	(7,360)		5.13			No	(9)
Q1 2011	(9,000)		5.75			No	(14)
Q2 2011	(9,100)		5.75			No	(14)
Q3 2011	(16,560)		5.42			No	(20)
Q4 2011	(16,560)		5.48			No	(18)
Knockout Swaps:							
Q4 2010	4,880	8.74	6.56			No	
Q1 2011	9,900	10.14	6.43			No	1
Q2 2011	4,550	9.62	6.05			No	1
Q3 2011	4,600	9.65	6.25			No	1
Q4 2011	4,600	9.73	6.25			No	2
Basis Protection Swaps							
(Non-Appalachian Basin):							
Q2 2011	19,147				(0.82)	No	(10)
Q3 2011	19,397				(0.82)	No	(9)

Q4 2011	6,545	(0.82)	No	(3)
2012	43,212	(0.85)	No	(21)
2013 2019	14,749	(1.03)	No	(10)

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			Weighted Average Price			**Cash Flow**	**Fair**
	Volume	**Fixed**	**Put**	**Call**	**Differential**	**Hedge**	**Value**
Natural Gas:	**(bbtu)**		**(per mmbtu)**				**($ in millions)**
Basis Protection Swaps (Appalachian Basin):							
Q4 2010	2,732	$	$	$	$ 0.26	No	$
Q1 2011	11,674				0.14	No	(1)
Q2 2011	12,186				0.14	No	
Q3 2011	12,403				0.14	No	1
Q4 2011	12,323				0.14	No	1
2012	14				0.19	No	
2013 2022	120				0.10	No	
Total Natural Gas							812

			Weighted Average Price			**Cash Flow**	**Fair**
	Volume	**Fixed**	**Put**	**Call**	**Differential**	**Hedge**	**Value**
Oil:	**(mbbl)**		**(per bbl)**				**($ in millions)**
Swaps:							
Q4 2010	460	$ 85.86		$	$	Yes	$ 2
Other Swaps[b]:							
Q4 2010	644	91.12				No	6
Q1 2011	810	91.17				No	(2)
Q2 2011	819	91.17				No	(2)
Q3 2011	828	91.17				No	(2)
Q4 2011	828	91.17				No	(3)
2012	1,830	100.00				No	(11)
2013	1,825	100.00				No	(16)
Call Options:							
Q4 2010	368			101.25		No	
Q1 2011[c]	2,250			74.81		No	(17)
Q2 2011[c]	2,275			74.81		No	(21)
Q3 2011[c]	2,300			74.81		No	(25)
Q4 2011[c]	2,300			74.81		No	(28)
2012[c]	9,150			74.81		No	(131)
2013 2015	23,616			87.82		No	(400)
Knock-Out Swaps:							
Q4 2010	1,196	90.25	60.00			No	11
Q1 2011	270	104.75	60.00			No	5
Q2 2011	273	104.75	60.00			No	4
Q3 2011	276	104.75	60.00			No	4
Q4 2011	276	104.75	60.00			No	3
2012	732	109.50	60.00			No	8
Total Oil							(615)
Total Natural Gas and Oil							$ 197

(a)

Included in Natural Gas Other Swaps are options to extend existing swaps for an additional 12 months. The volume of such extendables in 2011 is 69,350 bbtu at a weighted average fixed swap price of $8.74/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.

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In addition to the open derivative positions disclosed above, at September 30, 2010, we had $269 million of hedging gains related to option premiums and terminated trades that will be recorded within natural gas and oil sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses).

	September 30, 2010 ($ in millions)
Q4 2010	$ 109
Q1 2011	66
Q2 2011	81
Q3 2011	78
Q4 2011	66
2012	36
2013	(47)
2014 2022	(120)
Total	$ 269

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.

The table below reconciles the Current Period change in fair value of our natural gas and oil derivatives. Of the $197 million fair value asset, as of September 30, 2010, $1.087 billion relates to contracts maturing in the next 12 months, of which we expect to transfer approximately $188 million (net of income taxes) from accumulated other comprehensive income to net income (loss), and ($890) million relates to contracts maturing after 12 months. All transactions hedged as of September 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	1,378
Fair value of contracts when entered into	(303)
Contracts realized or otherwise settled	(1,229)
Fair value of contracts when closed	330
Fair value of contracts outstanding, as of September 30	$ 197

The change in natural gas and oil prices during the Current Period increased the value of our derivative assets by $1.378 billion. 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 $303 million, and a liability was recorded. We settled contracts, reducing our assets by $1.229 billion, and we closed out contracts, increasing our assets by $330 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 September 30,		**Nine Months Ended September 30,**	
	2010	**2009**	**2010**	**2009**
	($ in millions)			
Natural gas and oil sales	$ 1,074	$ 785	$ 3,243	$ 2,280
Realized gains (losses) on natural gas and oil derivatives	512	687	1,484	1,802
Unrealized gains (losses) on non-qualifying natural gas and oil derivatives	48	(278)	(9)	(484)
Unrealized gains (losses) on ineffectiveness of cash flow hedges	5	(7)	(20)	83
Total natural gas and oil sales	$ 1,639	$ 1,187	$ 4,698	$ 3,681

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Interest Rate Risk

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

	Years of Maturity						
	2010	2011	2012	2013	2014	Thereafter	Total
				($ in millions)			
Liabilities:							
Long-term debt fixed rate[(a)]	$	$	$	$ 500	$	$ 9,222	$ 9,722
Average interest rate				7.63%		6.05%	6.13%
Long-term debt variable rate		$	$ 2,237	$	$	$ 250	$ 2,487
Average interest rate			2.65%			3.01%	2.68%

(a) This amount does not include the discount included in long-term debt of ($800) million and interest rate derivatives of $36 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 September 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.

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.

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

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Weighted Average Rate Floating[(a)]	Fair Value Hedge	Net Premiums	Fair Value ($ in millions)
Fixed to Floating:						
Swaps						
Mature 2020	$ 250	6.88%	3 mL plus 287 bp	No	$	$ 29

Call Options								
Expire Q4 2010	$	250	6.88%	3 mL plus 287 bp	No	7		(26)
Swaption								
Expire Q4 2010	$	250	6.50%	3 mL plus 270 bp	No	4		
Floating to Fixed:								
Swaps								
Mature 2014	$	1,050	2.19%	1 6 mL	No			(42)
						$ 11	$	(39)

(a) 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 losses totaling $20 million. These losses are currently reported as an adjustment to our senior note liability, and will be amortized as an increase to realized interest expense over the remaining ten-year term of the related senior notes.

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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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
	($ in millions)			
Interest expense on senior notes	$ 167	$ 195	$ 550	$ 572
Interest expense on credit facilities	18	18	42	47
Capitalized interest	(185)	(153)	(525)	(467)
Realized (gains) losses on interest rate derivatives	(2)	(7)	(6)	(19)
Unrealized (gains) losses on interest rate derivatives	2	(20)	(75)	(106)
Amortization of loan discount and other	3	10	26	25
Total interest expense	$ 3	$ 43	$ 12	$ 52

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 $35 million at September 30, 2010. The euro-denominated debt in notes payable has been adjusted to $816 million at September 30, 2010 using an exchange rate of $1.3601 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 September 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 and our Prospectus Supplement filed with the Securities and Exchange Commission on August 10, 2010. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

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

The following table presents information about repurchases of our common stock during the three months ended September 30, 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]
July 1, 2010 through July 31, 2010	894,149	$ 21.05		
August 1, 2010 through August 31, 2010	8,193	$ 20.80		
September 1, 2010 through September 30, 2010	13,555	$ 22.30		
Total	915,897	$ 21.38		

(a) Includes the deemed surrender to the company of 12,285 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 903,612 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)***

ITEM 5. ***Other Information***

On November 5, 2010, the board of directors appointed Domenic J. Dell Osso, Jr., 34, as Executive Vice President and Chief Financial Officer of the company. Mr. Dell Osso previously served as Vice President Finance of the company and Chief Financial Officer of the company s wholly owned midstream subsidiary Chesapeake Midstream Development, L.P. from August 2008 to November 2010. Prior to joining the company, Mr. Dell Osso was an energy investment banker with Jefferies & Co. from April 2006 to August 2008, and Banc of America Securities from April 2004 to April 2006. Mr. Dell Osso graduated from Boston College in 1998 and from the University of Texas at Austin in 2003.

In connection with his appointment, Mr. Dell Osso entered into an employment agreement with the company, which is effective November 5, 2010 and will continue until September 30, 2012 in the absence of prior termination by the company or Mr. Dell Osso.

The employment agreement provides for Mr. Dell Osso to receive a Base Salary (as defined therein), cash bonus, equity compensation and certain other benefits. Subject to the limitations set forth therein, Mr. Dell Osso will receive (a) an annual Base Salary at the initial annual rate of not less than $450,000, which amount will increase to not less than $500,000 during the calendar year 2011 and not less than $600,000 during the calendar year 2012; (b) a special bonus of $100,000 on November 12, 2010, bonus compensation of not less than $500,000 during calendar year 2011 and bonus compensation of not less than $700,000 during calendar year 2012; and (c) an award of 20,000 shares of restricted stock of the company effective November 5, 2010, a minimum grant of $1,250,000 of restricted stock of the company during calendar year 2011 and a minimum grant of $2,400,000 of restricted stock of the company during calendar year 2012. The employment agreement also establishes a minimum stock ownership guideline for Mr. Dell Osso of 25,000 shares of the common stock of the company effective at all times after December 31, 2011 and prior to termination of the employment agreement.

The company may terminate the employment agreement with Mr. Dell Osso at any time without cause; however, upon such termination he is entitled, subject to his execution of a severance agreement, to (a) receive 52 weeks of his Base Salary in a lump sum payment; and (b) immediate vesting of all equity compensation awarded pursuant to the employment agreement and any supplemental matching contributions made pursuant to the company s Amended and Restated Deferred Compensation Plan.

The employment agreement further provides that if, during the term of the agreement, there is a Change of Control (as defined therein) of the company, Mr. Dell Osso will be entitled to a severance payment in an amount equal to 200% of the sum of (a) his then Base Salary as of the date of the Change of Control; and (b) the actual cash bonuses paid to Mr. Dell Osso under the employment agreement or its predecessor during the preceding 12 calendar months. Additionally, all equity compensation granted to Mr. Dell Osso under the employment agreement will be immediately vested.

The forgoing description is qualified in its entirety by reference to the employment agreement, a copy of which is filed herewith as Exhibit 10.2 and incorporated herein by reference.

In connection with his appointment, Mr. Dell Osso is also eligible to receive certain other compensation in the form of personal benefits and perquisites, which is provided to all executive officers of the company. The description of such compensatory arrangements (excluding the accounting services described) under the caption Other Compensation Arrangements in the company s definitive proxy statement, filed with the SEC on April 30, 2010, is incorporated by reference herein.

The company will also enter into a standard indemnity agreement with Mr. Dell Osso, a form of which was filed with the SEC on February 29, 2008 as Exhibit 10.3 to the company s 2007 Annual Report on Form 10-K. Pursuant to this agreement, subject to the exceptions and limitations provided therein, the company will indemnify Mr. Dell Osso for obligations he might incur in his capacity as an officer, as authorized by the company s restated certificate of incorporation.

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.	10-Q	001-13726	3.1.5	08/09/2010		
3.2	Chesapeake s Amended and Restated Bylaws.	8-K	001-13726	3.1	11/17/2008		
4.1	Indenture, dated as of August 2, 2010, by and among Chesapeake, as Issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee.	S-3	001-13726	4.1	08/03/2010		
4.1.1	First Supplemental Indenture dated as of August 17, 2010, by and among Chesapeake, as Issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.875% Senior Notes due 2018.	8-A	001-13726	4.2	9/24/2010		
4.1.1.1	Form of 6.875% Senior Note due 2018.	8-A	001-13726	4.4	9/24/2010		
4.1.2	Second Supplemental Indenture, dated as of August 17, 2010, by and among Chesapeake, as Issuer, the subsidiaries signatory thereto, as Subsidiary Guarantors, and the Bank of New York Mellon Trust Company, N.A., as Trustee, with respect to 6.625% Senior Notes due 2020.	8-A	001-13726	4.3	9/24/2010		
4.1.2.1	Form of 6.625% Senior Note due 2020.	8-A	001-13726	4.5	9/24/2010		
10.2						X	

	Employment Agreement, dated as of November 5, 2010, between Domenic J. Dell Osso, Jr., and Chesapeake Energy Corporation.	
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	X

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	2002.						
31.2	Domenic J. Dell Osso, Jr., 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	Domenic J. Dell Osso, Jr., 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: November 9, 2010	By:	/s/ AUBREY K. MCCLENDON Aubrey K. McClendon *Chairman of the Board and* *Chief Executive Officer*
Date: November 9, 2010	By:	/s/ DOMENIC J. DELL OSSO, JR. Domenic J. Dell Osso, Jr. *Executive Vice President and* *Chief Financial Officer*

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