CHESAPEAKE ENERGY CORP
Form 10-Q
November 06, 2013

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, 2013
[ ] 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 4, 2013, there were 665,098,207 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2013

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

	September 30, 2013	December 31, 2012
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$987	$287
Restricted cash	75	111
Accounts receivable	2,440	2,245
Short-term derivative assets	11	58
Deferred income tax asset	185	90
Other current assets	296	153
Current assets held for sale	—	4
Total Current Assets	3,994	2,948
PROPERTY AND EQUIPMENT:		
Natural gas and oil properties, at cost based on full cost accounting:		
Evaluated natural gas and oil properties ($488 and $488 attributable to our VIE)	55,175	50,172
Unevaluated properties	12,282	14,755
Oilfield services equipment	2,179	2,130
Other property and equipment	3,360	3,778
Total Property and Equipment, at Cost	72,996	70,835
Less: accumulated depreciation, depletion and amortization (($151) and ($58) attributable to our VIE)	(36,472)	(34,302)
Property and equipment held for sale, net	597	634
Total Property and Equipment, Net	37,121	37,167
LONG-TERM ASSETS:		
Investments	615	728
Long-term derivative assets	2	2
Other long-term assets	556	766
TOTAL ASSETS	$42,288	$41,611

The accompanying notes are an integral part of these condensed consolidated financial statements.
2

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

	September 30, 2013	December 31, 2012
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$1,730	$1,710
Short-term derivative liabilities ($7 and $4 attributable to our VIE)	170	105
Accrued interest	153	226
Current maturities of long-term debt, net	—	463
Other current liabilities ($24 and $21 attributable to our VIE)	3,625	3,741
Current liabilities held for sale	—	21
Total Current Liabilities	5,678	6,266
LONG-TERM LIABILITIES:		
Long-term debt, net	12,736	12,157
Deferred income tax liabilities	3,423	2,807
Long-term derivative liabilities ($1 and $3 attributable to our VIE)	519	934
Asset retirement obligations	404	375
Other long-term liabilities	1,180	1,176
Total Long-Term Liabilities	18,262	17,449
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders' Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,251,515 shares outstanding	3,062	3,062
Common stock, $0.01 par value, 1,000,000,000 shares authorized: 667,472,869 and 666,467,664 shares issued	7	7
Paid-in capital	12,443	12,293
Retained earnings	905	437
Accumulated other comprehensive loss	(169)	(182)
Less: treasury stock, at cost; 2,246,069 and 2,147,724 common shares	(52)	(48)
Total Chesapeake Stockholders' Equity	16,196	15,569
Noncontrolling interests	2,152	2,327
Total Equity	18,348	17,896
TOTAL LIABILITIES AND EQUITY	$42,288	$41,611

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	($ in millions except per share data)			
REVENUES:				
Natural gas, oil and NGL	$1,586	$1,437	$5,444	$4,622
Marketing, gathering and compression	3,032	1,381	6,871	3,710
Oilfield services	249	152	650	446
Total Revenues	4,867	2,970	12,965	8,778
OPERATING EXPENSES:				
Natural gas, oil and NGL production	282	320	877	1,005
Production taxes	62	53	173	141
Marketing, gathering and compression	3,009	1,339	6,781	3,631
Oilfield services	211	116	543	321
General and administrative	120	145	336	436
Restructuring and other termination benefits	63	3	203	4
Natural gas, oil and NGL depreciation, depletion and amortization	652	762	1,945	1,856
Depreciation and amortization of other assets	79	66	234	233
Impairment of natural gas and oil properties	—	3,315	—	3,315
Impairments of fixed assets and other	85	38	343	281
Net (gains) losses on sales of fixed assets	(132)	7	(290)	5
Total Operating Expenses	4,431	6,164	11,145	11,228
INCOME (LOSS) FROM OPERATIONS	436	(3,194)	1,820	(2,450)
OTHER INCOME (EXPENSE):				
Interest expense	(40)	(36)	(164)	(63)
Losses on investments	(22)	(23)	(26)	(87)
Impairment of investment	—	—	(10)	—
Gains (losses) on sales of investments	3	31	(7)	1,061
Losses on purchases of debt	—	—	(70)	—
Other income (expense)	10	(9)	18	2
Total Other Income (Expense)	(49)	(37)	(259)	913
INCOME (LOSS) BEFORE INCOME TAXES	387	(3,231)	1,561	(1,537)
INCOME TAX EXPENSE (BENEFIT):				
Current income taxes	7	22	9	24
Deferred income taxes	140	(1,282)	585	(623)
Total Income Tax Expense (Benefit)	147	(1,260)	594	(599)
NET INCOME (LOSS)	240	(1,971)	967	(938)
Net income attributable to noncontrolling interests	(38)	(41)	(127)	(131)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	202	(2,012)	840	(1,069)
Preferred stock dividends	(43)	(43)	(128)	(128)
Premium on purchase of preferred shares of a subsidiary	—	—	(69)	—
Earnings allocated to participating securities	(3)	—	(14)	—
	$156	$(2,055)	$629	$(1,197)

NET INCOME (LOSS) AVAILABLE TO COMMON STOCKHOLDERS				
EARNINGS (LOSS) PER COMMON SHARE:				
Basic	$0.24	$(3.19)	$0.96	$(1.86)
Diluted	$0.24	$(3.19)	$0.96	$(1.86)
CASH DIVIDEND DECLARED PER COMMON SHARE	$0.0875	$0.0875	$0.2625	$0.2625
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	656	644	654	643
Diluted	656	644	654	643

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	($ in millions)			
NET INCOME (LOSS)	$240	$(1,971)	$967	$(938)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:				
Unrealized gain on derivative instruments, net of income tax expense of $1 million, $1 million, $1 million and $1 million	2	3	2	3
Reclassification of (gain) loss on settled derivative instruments, net of income tax expense (benefit) of $1 million, ($3) million, $8 million and ($10) million	2	(6)	13	(18)
Unrealized loss on investments, net of income tax benefit of ($1) million, ($2) million, ($4) million and ($4) million	(1)	(3)	(6)	(7)
Reclassification of (gain) loss on investment, net of income tax expense (benefit) of ($1) million, $0, $3 million and $0	(2)	—	4	—
Other Comprehensive Income (Loss)	1	(6)	13	(22)
COMPREHENSIVE INCOME (LOSS)	241	(1,977)	980	(960)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(38)	(41)	(127)	(131)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$203	$(2,018)	$853	$(1,091)

The accompanying notes are an integral part of these condensed consolidated financial statements.
5

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME (LOSS)	$967	$(938)
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	2,179	2,089
Deferred income tax expense (benefit)	585	(623)
Derivative (income) expense	(90)	(828)
Cash (payments) receipts on derivative settlements, net	(91)	388
Stock-based compensation	78	93
Net (gains) losses on sales of fixed assets	(290)	6
Impairment of natural gas and oil properties	—	3,315
Impairments of fixed assets and other	317	256
Losses on investments	30	147
(Gains) losses on sales of investments	7	(1,061)
Losses on purchases of debt	12	—
Impairment of investment	10	—
Restructuring and other termination benefits	164	4
Other	35	76
Changes in assets and liabilities	(352)	(946)
Net Cash Provided By Operating Activities	3,561	1,978
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(4,470)	(7,525)
Acquisitions of proved and unproved properties	(811)	(2,813)
Proceeds from divestitures of proved and unproved properties	2,789	2,445
Additions to other property and equipment	(639)	(1,916)
Proceeds from sales of other assets	796	219
Additions to investments	(8)	(261)
Proceeds from sales of investments	115	2,000
(Increase) decrease in restricted cash	177	(280)
Other	4	(23)
Net Cash Used In Investing Activities	(2,047)	(8,154)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from credit facilities borrowings	7,136	13,986
Payments on credit facilities borrowings	(7,268)	(13,614)
Proceeds from issuance of senior notes, net of discount and offering costs	2,274	1,263
Proceeds from issuance of term loans, net of discount and offering costs	—	3,789
Cash paid to purchase debt	(2,116)	—
Cash paid for common stock dividends	(175)	(170)
Cash paid for preferred stock dividends	(128)	(128)
Cash paid on financing derivatives	(62)	(36)
Cash paid for prepayment of mortgage	(55)	—
Proceeds from sales of noncontrolling interests	5	1,056

Proceeds from other financings	22	225
Cash paid to purchase preferred shares of a subsidiary	(212)	—
Distributions to noncontrolling interest owners	(164)	(163)
Other	(71)	(227)
Net Cash Provided By (Used In) Financing Activities	(814)	5,981
Change in cash and cash equivalents classified as current assets held for sale	—	(14)
Net increase (decrease) in cash and cash equivalents	700	(209)
Cash and cash equivalents, beginning of period	287	351
Cash and cash equivalents, end of period	$987	$142

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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS – (Continued)
(Unaudited)

Supplemental disclosures to the condensed consolidated statements of cash flows are presented below:

	Nine Months Ended September 30,	
	2013	2012
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest, net of capitalized interest	$62	$—
Income taxes, net of refunds received	$14	$31
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$(97)	$(103)
Change in accrued acquisitions of proved and unproved properties	$(1)	$60
Change in accrued additions to other property and equipment	$(80)	$57

The accompanying notes are an integral part of these condensed consolidated financial statements.
7

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning and end of period	$3,062	$3,062
COMMON STOCK:		
Balance, beginning and end of period	7	7
PAID-IN CAPITAL:		
Balance, beginning of period	12,293	12,146
Stock-based compensation	156	116
Reduction in tax benefit from stock-based compensation	(10)	(18)
Exercise of stock options	4	2
Balance, end of period	12,443	12,246
RETAINED EARNINGS:		
Balance, beginning of period	437	1,608
Net income (loss) attributable to Chesapeake	840	(1,069)
Dividends on common stock	(175)	(170)
Dividends on preferred stock	(128)	(128)
Premium on purchase of preferred shares of a subsidiary	(69)	—
Balance, end of period	905	241
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(182)	(166)
Hedging activity	15	(15)
Investment activity	(2)	(7)
Balance, end of period	(169)	(188)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(48)	(33)
Purchase of 249,498 and 357,565 shares for company benefit plans	(6)	(9)
Release of 151,153 and 49,591 shares from company benefit plans	2	1
Balance, end of period	(52)	(41)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY	16,196	15,327
NONCONTROLLING INTERESTS:		
Balance, beginning of period	2,327	1,337
Sales of noncontrolling interests	5	1,056
Net income attributable to noncontrolling interests	127	131
Distributions to noncontrolling interest owners	(164)	(160)
Purchase of preferred shares of a subsidiary	(143)	—
Balance, end of period	2,152	2,364
TOTAL EQUITY	$18,348	$17,691

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

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

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation (“Chesapeake” or the “Company”) and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission (SEC). This Form 10-Q relates to the three and nine months ended September 30, 2013 (the “Current Quarter” and the “Current Period”, respectively) and the three and nine months ended September 30, 2012 (the “Prior Quarter” and the “Prior Period”, respectively). Chesapeake’s annual report on Form 10-K for the year ended December 31, 2012 (“2012 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 presentation of the results for the interim periods have been reflected. The accompanying condensed consolidated financial statements of Chesapeake include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake holds a controlling interest. All significant intercompany accounts and transactions have been eliminated. The results for the Current Quarter and Current Period are not necessarily indicative of the results to be expected for the full year.

Critical Accounting Policies

We consider accounting policies related to variable interest entities, natural gas and oil properties, derivatives and income taxes to be critical policies. These policies are summarized in Item 7 of our 2012 Form 10-K.

Risks and Uncertainties

Our primary business strategy over the last few years was to continue growing our reserves and production while transitioning from an asset base primarily focused on natural gas to an asset base more balanced between natural gas and liquids production. This was a capital-intensive strategy, and we made capital expenditures historically and in the Current Period that exceeded our cash flow from operations, supplementing such cash flows with borrowings, proceeds from strategic joint ventures and sales of assets that we determined were noncore or did not fit our long-term plans. The full year 2013 gap between forecasted capital expenditures and expected cash flow from operations is approximately $3.5 billion; however, this expected spending gap has been fully covered by joint venture and asset sales proceeds received year to date. We are working to execute our business with greater financial discipline and are targeting to balance capital expenditures with cash flow from operations over time. We expect to have the flexibility to fund any short-term disparities using our $4.0 billion corporate revolving credit facility, which was undrawn at September 30, 2013. As we apply available cash from future asset sales and operations towards reducing our financial leverage and complexity, we may incur various cash and noncash charges including but not limited to impairments of fixed assets, lease termination charges or financing extinguishment costs.

We continue to have significant exposure to natural gas prices. Approximately 70% of our estimated proved reserve volumes as of December 31, 2012 were natural gas, and natural gas represented approximately 73% and 80% of our natural gas, oil and NGL sales volumes for the Current Quarter and the year ended December 31, 2012, respectively. To add more certainty to our future estimated cash flows, we currently have downside price protection, in the form of over-the-counter derivative contracts, on approximately 80% of our remaining 2013 estimated natural gas production at an average price of $3.69 per mcf and 91% of our remaining 2013 estimated oil production at an average price of $95.59 per bbl. We also have derivative contracts providing downside price protection in 2014 on 251 bcf of natural gas at an average price of $4.22 per mcf and 22 mmbbls of oil at an average price of $93.79 per bbl. While our use of derivative contracts allows us to reduce our exposure to price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization), the derivative contracts we elect to enter into for any period depend on our outlook on future prices and our risk assessment. Low natural gas, oil and NGL prices can reduce our estimate of proved reserves, potentially resulting in a future write-down of the carrying value of our natural gas and oil properties. In 2012, when natural gas prices reached 10-year lows, we reduced our estimate of proved reserves by 3.1 tcfe, or 17%, primarily due to the impact of downward natural gas price revisions, and we incurred a $3.3 billion write-down of the carrying value of our natural gas and oil properties. Future impairments of the carrying value of our natural gas and oil properties, if any, will be dependent on many factors, including natural gas, oil and NGL prices, production rates, levels of reserves, the evaluation of costs excluded from amortization, the timing and impact of asset sales, future development costs and service costs.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Assets and Liabilities Held for Sale
In the Current Period, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. In addition, as of September 30, 2013, we were continuing to pursue the sale of various land and buildings located in the Fort Worth, Texas area. The land and buildings in both the Oklahoma City and Fort Worth areas are reported under our other segment. We are also pursuing the sale of various other property and equipment, including certain drilling rigs, compressors and gathering systems. The drilling rigs are reported under our oilfield services operating segment and the compressors and gathering systems are reported under our marketing, gathering and compression operating segment. These assets are being actively marketed, and we believe it is probable they will be sold over the next 12 months. As a result, these assets qualified as held for sale as of September 30, 2013. Natural gas and oil properties that we intend to sell are not presented as held for sale pursuant to the rules governing full cost accounting for oil and gas properties. A summary of the assets and liabilities held for sale on our condensed consolidated balance sheets as of September 30, 2013 and December 31, 2012 is detailed below.

	September 30, 2013	December 31, 2012
	($ in millions)	
Accounts receivable	$—	$4
Current assets held for sale	$—	$4
Natural gas gathering systems and treating plants, net of accumulated depreciation	$10	$352
Oilfield services equipment, net of accumulated depreciation	26	27
Compressors, net of accumulated depreciation	242	—
Buildings and land, net of accumulated depreciation	319	255
Property and equipment held for sale, net	$597	$634
Accounts payable	$—	$4
Accrued liabilities	—	17
Current liabilities held for sale	$—	$21

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Accumulated Other Comprehensive Income (Loss)

For the Current Period, changes in accumulated other comprehensive income (loss) by component, net of tax, are detailed below.

	Net Gains (Losses) on Cash Flow Hedges	Net Gains (Losses) on Investments	Total
	($ in millions)		
Balance, December 31, 2012	$(189)	$7	$(182)
Other comprehensive income before reclassifications	2	(6)	(4)
Amounts reclassified from accumulated other comprehensive income	13	4	17
Net current period other comprehensive income	15	(2)	13
Balance, September 30, 2013	$(174)	$5	$(169)

For the Current Quarter and the Current Period, amounts reclassified from accumulated other comprehensive income (loss), net of tax, into the condensed consolidated statement of operations are detailed below.

Details About Accumulated Other Comprehensive Income (Loss) Components	Affected Line Item in the Statement Where Net Income is Presented	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013
		($ in millions)	
Net losses on cash flow hedges:			
Commodity contracts	Natural gas, oil and NGL revenues	$2	$13
Investments:			
Impairment of investment	Impairment of investment	—	6
Sale of investment	Gain on sale of investment	(2)	(2)
Total reclassifications for the period, net of tax		$—	$17

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

2. Earnings Per Share

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, our contingent convertible senior notes did not have a dilutive effect and therefore were excluded from the calculation of diluted earnings per share (EPS). See Note 3 for further discussion of our contingent convertible senior notes. Participating securities, for purposes of our EPS computations, consist of unvested restricted stock issued to our employees and non-employee directors that provide dividend rights.

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, the following shares of cumulative convertible preferred stock and unvested restricted stock and associated adjustments to net income, consisting of dividends on such shares, were excluded from the calculation of diluted EPS, as the effect was antidilutive:

	Net Income Adjustments ($ in millions)	Shares (in millions)
Three Months Ended September 30, 2013:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$21	56
5.75% cumulative convertible preferred stock (series A)	$16	39
5.00% cumulative convertible preferred stock (series 2005B)	$3	5
4.50% cumulative convertible preferred stock	$3	6
Unvested restricted stock	$3	2
Three Months Ended September 30, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$21	56
5.75% cumulative convertible preferred stock (series A)	$16	39
5.00% cumulative convertible preferred stock (series 2005B)	$3	5
4.50% cumulative convertible preferred stock	$3	6
Unvested restricted stock	$—	3
Nine Months Ended September 30, 2013:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$64	56
5.75% cumulative convertible preferred stock (series A)	$47	40
5.00% cumulative convertible preferred stock (series 2005B)	$8	5
4.50% cumulative convertible preferred stock	$9	6
Unvested restricted stock	$14	3
Nine Months Ended September 30, 2012:		
Common stock equivalent of our preferred stock outstanding:		
5.75% cumulative convertible preferred stock	$64	56
5.75% cumulative convertible preferred stock (series A)	$47	39
5.00% cumulative convertible preferred stock (series 2005B)	$8	5
4.50% cumulative convertible preferred stock	$9	6
Unvested restricted stock	$—	4

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

3. Debt

Our long-term debt consisted of the following as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	($ in millions)	
Term loan due 2017	$2,000	$2,000
7.625% senior notes due 2013	—	464
9.5% senior notes due 2015	1,265	1,265
3.25% senior notes due 2016	500	—
6.25% euro-denominated senior notes due 2017[a]	465	454
6.5% senior notes due 2017	660	660
6.875% senior notes due 2018	97	474
7.25% senior notes due 2018	669	669
6.625% senior notes due 2019[b]	650	650
6.775% senior notes due 2019	—	1,300
6.625% senior notes due 2020	1,300	1,300
6.875% senior notes due 2020	500	500
6.125% senior notes due 2021	1,000	1,000
5.375% senior notes due 2021	700	—
5.75% senior notes due 2023	1,100	—
2.75% contingent convertible senior notes due 2035[c]	396	396
2.5% contingent convertible senior notes due 2037[c]	1,168	1,168
2.25% contingent convertible senior notes due 2038[c]	347	347
Corporate revolving bank credit facility	—	—
Oilfield services revolving bank credit facility	285	418
Discount on senior notes and term loan[d]	(380)	(465)
Interest rate derivatives[e]	14	20
Total debt, net	12,736	12,620
Less current maturities of long-term debt, net[f]	—	(463)
Total long-term debt, net	$12,736	$12,157

(a) The principal amount shown is based on the exchange rate of $1.3527 to €1.00 and $1.3193 to €1.00 as of September 30, 2013 and December 31, 2012, respectively. See Note 7 for information on our related foreign currency derivatives.

(b) Issuers are Chesapeake Oilfield Operating, L.L.C. (COO), an indirect wholly owned subsidiary of the Company, and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. One such triggering circumstance is 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 quarterly. In the Current Quarter, 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

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

their notes into cash and common stock in the fourth quarter of 2013 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. During the Current Quarter, the notes were not convertible under this provision. 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 in which 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	$48.31	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$63.62	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$107.01	June 14, 2019

(d) Discount as of September 30, 2013 and December 31, 2012 included $322 million and $376 million, respectively, associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method. The discount also included $34 million and $40 million as of September 30, 2013 and December 31, 2012, respectively, associated with our term loan discussed further below.

(e) See Note 7 for further discussion related to these instruments.

(f) As of December 31, 2012, there was $1 million of discount associated with the 7.625% Senior Notes due 2013.

Term Loan

In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion. Our obligations under the facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the facility bear interest at our option, at either (i) the Eurodollar rate, which is based on the London Interbank Offered Rate (LIBOR), plus a margin of 4.50% or (ii) a base rate equal to the greater of (a) the Bank of America, N.A. prime rate, (b) the federal funds effective rate plus 0.50% per annum and (c) the Eurodollar rate that would be applicable to a Eurodollar loan with an interest period of one month plus 1% per annum, in each case, plus a margin of 3.50%. The Eurodollar rate is subject to a floor of 1.25% per annum, and the base rate is subject to a floor of 2.25% per annum. Interest is payable quarterly or, if the Eurodollar rate applies, it may be payable at more frequent intervals.

The term loan matures on December 2, 2017 and may be voluntarily repaid at a make-whole price in the first year, at par plus a specified premium in the second and third years and at any time thereafter at par. The term loan may also be refinanced or amended to extend the maturity date at our option, subject to lender approval.

The term loan credit agreement contains negative covenants substantially similar to those contained in the Company's corporate revolving bank credit facility, including covenants that limit our ability to incur indebtedness, grant liens, make investments, loans and restricted payments and enter into certain business combination transactions. Other covenants include additional restrictions regarding the incurrence of certain unsecured indebtedness, the incurrence of secured indebtedness, the disposition of assets and the prepayment of certain indebtedness. The term loan credit agreement does not contain financial maintenance covenants.

We were in compliance with all covenants under the term loan credit agreement as of September 30, 2013. If we should fail to perform our obligations under the agreement, the term loan could be terminated and any outstanding borrowings under the term loan credit agreement could be declared immediately due and payable. The term loan credit

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

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 $125 million.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

The Chesapeake senior notes and the contingent convertible senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior unsecured 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. Chesapeake's obligations under the senior notes and the contingent convertible senior notes are jointly and severally, fully and unconditionally guaranteed by certain of our direct and indirect wholly owned subsidiaries. See Note 16 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 may limit our ability and our subsidiaries' ability to incur certain secured indebtedness, enter into sale/leaseback transactions, and consolidate, merge or transfer assets. The indentures governing the senior notes and the contingent convertible senior notes do not have any financial or restricted payment covenants. The senior notes and contingent convertible senior notes indentures have cross default provisions that apply to other indebtedness the Company or any guarantor subsidiary may have from time to time with an outstanding principal amount of at least $50 million, depending on the indenture.

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. The applicable 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.

During the Current Period, we issued $2.3 billion in aggregate principal amount of senior notes at par in a registered public offering. The offering included three series of notes: $500 million in aggregate principal amount of 3.25% Senior Notes due 2016; $700 million in aggregate principal amount of 5.375% Senior Notes due 2021; and $1.1 billion in aggregate principal amount of 5.75% Senior Notes due 2023. We used a portion of the net proceeds of $2.274 billion to repay outstanding indebtedness under our corporate revolving bank credit facility and purchase certain senior notes. We purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to tender offers which expired on April 12, 2013. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. During the Current Quarter, we retired at maturity the remaining $247 million aggregate principal amount outstanding of our 7.625% Senior Notes due 2013.

During the Prior Period, we issued $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 (the "2019 Notes") in a registered public offering. We used the net proceeds of $1.263 billion from the offering to repay outstanding indebtedness under our corporate revolving bank credit facility. On May 13, 2013, we redeemed the 2019 Notes at par pursuant to notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount. As described in the following paragraph, the special early redemption was the subject of recent litigation.

In March 2013, the Company brought suit in the U.S. District Court for the Southern District of New York (the "Court") against The Bank of New York Mellon Trust Company, N.A. ("BNY Mellon"), the indenture trustee for the 2019 Notes. The Company sought a declaration that the notice it issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) was timely and effective pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes. BNY Mellon asserted that the March 15, 2013 notice was not effective to redeem the 2019 Notes at par because it was not timely for that purpose and because of the specific phrasing in the notice that provided it would not be effective unless the Court concluded it was timely. The

Court conducted a trial on the matter in late April and on May 8, 2013 ruled in the Company’s favor. On May 11, 2013, BNY Mellon filed notice of an appeal of the decision with the United States Court of Appeals for the Second Circuit and the appeal is currently pending.

No scheduled principal payments are required on our senior notes until 2015.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

COO Senior Notes

The COO senior notes are the unsecured senior obligations of COO and rank equally in right of payment with all of COO's other existing and future senior unsecured indebtedness and rank senior in right of payment to all of its future subordinated indebtedness. The COO senior notes are jointly and severally, fully and unconditionally guaranteed by all of COO's wholly owned subsidiaries, other than de minimis subsidiaries. The notes may be redeemed by COO at any time at specified make-whole or redemption prices and, prior to November 15, 2014, up to 35% of the aggregate principal amount may be redeemed in connection with certain equity offerings. Holders of the COO notes have the right to require COO to repurchase their notes upon a change of control on the terms set forth in the indenture, and COO must offer to repurchase the notes upon certain asset sales. The COO senior notes are subject to covenants that may, among other things, limit the ability of COO and its subsidiaries to make restricted payments, incur indebtedness, issue preferred stock, create liens, and consolidate, merge or transfer assets. The COO senior notes have cross default provisions that apply to other indebtedness COO or any of its guarantor subsidiaries may have from time to time with an outstanding principal amount of $50 million or more.

Under a registration rights agreement, we agreed to file a registration statement enabling holders of the COO senior notes to exchange the privately placed COO senior notes for publicly registered notes with substantially the same terms. The exchange offer was completed on July 19, 2013.

Bank Credit Facilities

During the Current Period, we had two revolving bank credit facilities as sources of liquidity. In addition, in the Prior Period, we had a midstream credit facility. In June 2012, we paid off and terminated our midstream credit facility. Our remaining revolving bank credit facilities are described below.

	Corporate Credit Facility[(a)]	Oilfield Services Credit Facility[(b)]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of September 30, 2013	$—	$285
Letters of credit outstanding as of September 30, 2013	$23	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower is COO.

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, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility. Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by 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 0.50% to 1.25% per annum according to our senior unsecured long-term debt ratings, or (ii) the Eurodollar rate, which is based on 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% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

16

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Our corporate 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 our corporate credit facility agreement as of September 30, 2013.

In September 2012, we entered into an amendment to the credit facility agreement, effective September 30, 2012. The amendment, among other things, adjusted our required indebtedness to EBITDA ratio through the earlier of (i) December 31, 2013 and (ii) the date on which we elected to reinstate the indebtedness to EBITDA ratio in effect prior to the amendment (in either case, the “Amendment Effective Period”). The credit facility amendment also increased the applicable margin by 0.25% for borrowings during the Amendment Effective Period when credit extensions exceeded 50% of the borrowing capacity. The amendment did not allow our collateral value securing the borrowings to be more than $75 million below the collateral value that was in effect as of September 30, 2012 during the Amendment Effective Period. During the Amendment Effective Period, the amendment increased the maximum indebtedness to EBITDA ratio to 6.00 to 1.00 as of September 30, 2012, 5.00 to 1.00 as of December 31, 2012 and 4.75 to 1.00 as of March 31, 2013. On June 28, 2013, we elected to reinstate the indebtedness to EBITDA ratio to 4.00 to 1.00, which was the ratio in effect prior to the amendment.

Our corporate credit facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and certain of our wholly owned subsidiaries. If we should fail to perform our obligations under the credit facility agreement, 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 and contingent convertible senior note indentures, which could in turn result in the acceleration of a significant portion of such indebtedness. The credit facility agreement also has cross default provisions that apply to our secured hedging facility, equipment master lease agreements, term loan and other indebtedness of Chesapeake and its restricted subsidiaries with an outstanding principal amount in excess of $125 million. In addition, the facility contains a restriction on our ability to declare and pay cash dividends on our common or preferred stock if an event of default has occurred.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. Borrowings under the oilfield services credit facility are secured by all of the assets of the wholly owned subsidiaries of COO, itself an indirect wholly owned subsidiary of Chesapeake. The facility has initial commitments of $500 million and may be expanded to $900 million at COO’s option, subject to additional bank participation. Borrowings under the credit facility are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, which are unrestricted subsidiaries under Chesapeake’s senior notes, contingent convertible senior notes, term loan and corporate revolving bank credit facility), and bear interest at our option at either (i) the greater of the reference rate of Bank of America, N.A., the federal funds effective rate plus 0.50%, or one-month LIBOR plus 1.00%, all of which are subject to a margin that varies from 1.00% to 1.75% per annum, or (ii) the Eurodollar rate, which is based on LIBOR plus a margin that varies from 2.00% to 2.75% per annum. The unused portion of the credit facility is subject to a commitment fee that varies from 0.375% to 0.50% per annum. Both margins and commitment fees are determined according to the most recent leverage ratio described below. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The oilfield services credit facility agreement contains various covenants and restrictive provisions which limit the ability of COO and its restricted subsidiaries to enter into asset sales, incur additional indebtedness, make investments or loans and create liens. The agreement requires maintenance of a leverage ratio based on the ratio of lease-adjusted indebtedness to earnings before interest, taxes, depreciation, amortization and rent (EBITDAR), a senior secured leverage ratio based on the ratio of secured indebtedness to EBITDA and a fixed charge coverage ratio based on the ratio of EBITDAR to lease-adjusted interest expense, in each case as defined in the agreement. COO was in compliance with all covenants under the agreement as of September 30, 2013. If COO or its restricted subsidiaries should fail to perform their obligations under the agreement, 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 COO senior note indenture, which could in turn result in the acceleration of the COO senior note indebtedness. The oilfield services credit facility agreement also has cross default provisions that apply to other indebtedness COO and its restricted subsidiaries may have from time to time with an outstanding principal amount in excess of $15 million.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

4. Contingencies and Commitments
Contingencies
Litigation and Regulatory Proceedings
The Company is involved in a number of litigation and regulatory proceedings (including those described below). Many of these proceedings are in early stages, and many of them seek an indeterminate amount of damages. We estimate and provide for potential losses that may arise out of litigation and regulatory proceedings to the extent that such losses are probable and can be reasonably estimated. Significant judgment is required in making these estimates and our final liabilities may ultimately be materially different. Our total estimated liability in respect of litigation and regulatory proceedings is determined on a case-by-case basis and represents an estimate of probable losses after considering, among other factors, the progress of each case or proceeding, our experience and the experience of others in similar cases or proceedings, and the opinions and views of legal counsel. We account for legal defense costs in the period the costs are incurred.
July 2008 Common Stock Offering. 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. 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. Chesapeake and the officer and director defendants moved for summary judgment on grounds of loss causation and materiality on December 28, 2011, and the motion was granted as to all claims as a matter of law on March 29, 2013. Final judgment in favor of Chesapeake and the officer and director defendants was entered on June 21, 2013, and the plaintiff filed a notice of appeal on July 19, 2013 in the U.S. Court of Appeals for the Tenth Circuit. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.
A derivative action relating to the July 2008 offering filed in the U.S. District Court for the Western District of Oklahoma on September 6, 2011 is pending. Following the denial on September 28, 2012 of its motion to dismiss and pursuant to court order, nominal defendant Chesapeake filed an answer in the case on October 12, 2012. By stipulation between the parties, the individual defendants are not required to answer the complaint unless and until the plaintiff establishes standing to pursue claims derivatively.
2012 Securities and Shareholder Litigation. A putative class action was filed in the U.S. District Court for the Western District of Oklahoma on April 26, 2012 against the Company and its former CEO, Aubrey K. McClendon. On July 20, 2012, the court appointed a lead plaintiff, which filed an amended complaint on October 19, 2012 against the Company, Mr. McClendon and certain other officers. The amended complaint asserted claims under Sections 10(b) (and Rule 10b-5 promulgated thereunder) and 20(a) of the Securities Exchange Act of 1934 based on alleged misrepresentations regarding the Company’s asset monetization strategy, including liabilities associated with its volumetric production payment (VPP) transactions, as well as Mr. McClendon’s personal loans and the Company’s internal controls. On December 6, 2012, the Company and other defendants filed a motion to dismiss the action. On April 10, 2013, the Court granted the motion, and on April 16, 2013 entered judgment against the plaintiff and dismissed the complaint with prejudice. The plaintiff filed a notice of appeal on June 14, 2013 in the U.S. Court of Appeals for the Tenth Circuit. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.
A related federal consolidated derivative action and an Oklahoma state court derivative action are stayed pursuant to the parties' stipulation pending resolution of the appeal in the federal securities class action. Two additional related state court derivative actions were appealed to the Oklahoma Supreme Court, one on May 31, 2013 and the other on June 20, 2013. In both cases, the District Court of Oklahoma County, Oklahoma had granted Chesapeake's motion to dismiss for lack of derivative standing.

In June and July 2012, three putative class actions were filed in the U.S. District Court for the Western District of Oklahoma against the Company, Chesapeake Energy Savings and Incentive Stock Bonus Plan (the Plan), and certain of the Company's officers and directors alleging breaches of fiduciary duties under the Employee Retirement Income Security Act (ERISA). The three cases have been consolidated, and the Plan was not named in the consolidated amended complaint which was filed on February 21, 2013. The action was brought on behalf of participants and beneficiaries of the Plan and alleged that, as fiduciaries of the Plan, defendants owed fiduciary duties, which they purportedly breached by, among other things, failing to manage and administer the Plan's assets with appropriate skill and care and engaging in activities that were in conflict with the best interest of the Plan. The plaintiffs sought class certification, damages of an unspecified amount, equitable relief, and attorneys' fees and other costs. The defendants filed a motion to dismiss on April 22, 2013, which was granted on October 11, 2013. We are currently unable to assess the probability of loss or estimate a range of potential loss associated with this matter.

On May 8, 2012, a derivative action was filed in the District Court of Oklahoma County, Oklahoma against the Company's directors alleging, among other things, breaches of fiduciary duties and corporate waste related to the Company's officers, and directors' use of the Company's fractionally owned corporate jets. On August 21, 2012, the District Court granted the Company's motion to dismiss for lack of derivative standing, and the plaintiff appealed the ruling on December 6, 2012.

Regulatory Proceedings. On May 2, 2012, Chesapeake and Mr. McClendon received notice from the U.S. Securities and Exchange Commission that its Fort Worth Regional Office had commenced an informal inquiry into, among other things, certain of the matters alleged in the foregoing lawsuits. On December 21, 2012, the SEC's Fort Worth Regional Office advised Chesapeake that its inquiry is continuing as an investigation. The Company is providing information and testimony to the SEC pursuant to subpoenas and otherwise in connection with this matter and is also responding to related inquiries from other governmental and regulatory agencies and self-regulatory organizations.

The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state laws relating to our purchase and lease of oil and gas rights. Chesapeake has engaged in discussions with the DOJ and state agencies and continues to respond to such subpoenas and demands, including the subpoena issued by the DOJ's Antitrust Division, Midwest Field Office on June 29, 2012 relating to an investigation into possible violations of antitrust laws being conducted by a grand jury in the Western District of Michigan and a subpoena issued by the Michigan Department of Attorney General on September 16, 2013 relating to its investigation of possible violations of that state's criminal solicitation law. Chesapeake's Board of Directors commenced in June 2012 its own investigation of certain conduct covered by the DOJ subpoena, and in February 2013, the Company announced the Board's conclusion that the Company did not violate antitrust laws in connection with the acquisition of Michigan oil and gas rights in 2010.

Business Operations. Chesapeake is involved in various other lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, royalty claims, property damage claims and contract actions. With regard to contract actions, various mineral or leasehold owners have filed lawsuits against us seeking specific performance to require us to acquire their natural gas and oil interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal. Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits allege that we used below-market prices, made improper deductions, used improper measurement techniques and/or entered into arrangements with affiliates that resulted in underpayment of royalties in connection with the production and sale of natural gas and NGL. The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits.

Based on management's current assessment, we are of the opinion that no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its 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

The nature of the natural gas and oil business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, procedures, training and auditing to reduce and mitigate such environmental risks. Chesapeake conducts periodic reviews, on a company-wide basis, to assess changes in our environmental risk profile. Environmental reserves are set for environmental liabilities for which economic losses are probable and reasonably estimable. We manage our exposure to environmental liabilities in acquisitions by using an evaluation process that seeks to identify pre-existing contamination or compliance concerns and addressing the potential liability. Depending on the extent of an identified environmental concern, Chesapeake may, among other things, exclude a property from the transaction, require the seller to remediate the property to our satisfaction in an acquisition or agree to assume liability for the remediation of the property.

There are presently pending against our subsidiary, Chesapeake Appalachia, L.L.C. (CALLC), orders for compliance first initiated in the 2010 fourth quarter by the U.S. Environmental Protection Agency (EPA) related to our compliance with Clean Water Act (CWA) permitting requirements in West Virginia. We have responded to all pending orders and are actively working with the EPA to resolve these and similar matters. We expect that resolution of pending EPA matters will include monetary sanctions exceeding $100,000, but we believe any associated liability will not have a material effect on the consolidated financial position, results of operations or cash flow of the Company.

For one West Virginia site that was subject to an EPA order for compliance, CALLC pled guilty on December 3, 2012 to three misdemeanor counts of unauthorized discharge of dredged or fill materials into a water of the U.S. We have paid the applicable fine in full, our restoration of the site has been completed and approved by the government, and we believe that CALLC is in compliance with the terms of probation. By operation of law, a CWA conviction triggers “disqualification”, by which the disqualified entity is prohibited from receiving federal contracts or benefits until the EPA certifies that the conditions giving rise to the conviction have been corrected. Disqualification of CALLC has not had, and we do not expect it to have, a material adverse impact on our business.

Commitments

Rig Leases

In a series of transactions beginning in 2006, our drilling subsidiary sold 94 drilling rigs (of which 28 rigs have been repurchased) and related equipment and entered into master lease agreements under which we agreed to lease the rigs from the buyer for initial terms of five to ten years. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks and any related net gains are amortized to oilfield services expenses over the lease term. Under the leases, we can exercise an early purchase option or we can purchase the rigs at the expiration of the lease for the fair market value at the time. In addition, in most cases, we have the option to renew a lease for negotiated new terms at the expiration of the lease. Commitments related to rig lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2013, the minimum aggregate undiscounted future rig lease payments were approximately $239 million. Subsequent to September 30, 2013, we repurchased nine rigs for approximately $70 million from lessors, lowering our minimum aggregate undiscounted future rig lease payments by approximately $58 million. See Note 18 for further discussion of the repurchases.

Chesapeake has contracts with various drilling contractors to utilize approximately 11 rigs with terms ranging from one to three years. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2013, the aggregate undiscounted minimum future payments under these drilling rig commitments were approximately $82 million.

Compressor Leases

Through various transactions beginning in 2007, our compression subsidiary sold 2,558 compressors (of which 250 units have been repurchased), a significant portion of its compressor fleet, and entered into a master lease agreement under which we agreed to lease the compressors from the buyer for initial terms of four to ten years. The lease commitments are guaranteed by Chesapeake and certain of its subsidiaries. These transactions were recorded as sales and operating leasebacks, and any related net gains are 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 the expiration of the lease for the fair market value at the time. In addition, in most cases we have the option to renew a 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, 2013, the minimum aggregate undiscounted future compressor lease payments were approximately $348 million.

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of natural gas and liquids to move certain of our production to market. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. Commitments related to gathering, processing and transportation agreements are not recorded in the accompanying condensed consolidated balance sheets; however, they are reflected as adjustments to future natural gas, oil and NGL sales prices used in our proved reserves estimates.

The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any reimbursement from working interest and royalty interest owners, are presented below.

	September 30, 2013 ($ in millions)
2013	$510
2014	2,010
2015	1,821
2016	1,910
2017	1,942
2018 - 2099	9,546
Total	$17,739

Drilling Commitments

In December 2011, as part of our Utica joint venture development agreement with Total S.A. (Total) (see Note 8), we committed to spud no less than 90 cumulative Utica wells by December 31, 2012, 270 cumulative wells by December 31, 2013 and 540 cumulative wells by July 31, 2015. Through September 30, 2013, we had spud 357 cumulative Utica wells and had met our 2012 and 2013 commitments. If we fail to meet the drilling commitment at July 31, 2015 for any reason other than a force majeure event, the drilling carry percentage used to determine our promoted well reimbursement will be reduced from 60% to 45% for the number of wells drilled in the subsequent 12-month period represented by the shortfall versus our drilling commitment. As such, any reduction would only affect the timing of the receipt of the drilling carry but not the total drilling carry to be received.

We have also committed to drill wells in conjunction with our CHK Utica and CHK C-T financial transactions and in conjunction with the formation of the Chesapeake Granite Wash Trust. See Note 6 for discussion of these transactions and commitments.

Property and Equipment Purchase Commitments

Much of the oilfield services and other equipment we purchase requires long production lead times. As a result, we have outstanding orders and commitments for such equipment. As of September 30, 2013, we had $50 million of purchase commitments related to future inventory and capital expenditures for oilfield services and other equipment.

Natural Gas and Liquids Purchase Commitments

We regularly commit to purchase natural gas and liquids from other owners in the properties we operate, including owners associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices. See Note 8 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our joint venture agreements with Statoil, Total and Sinopec (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. To date, we have satisfied our replacement commitments under the Statoil and Sinopec agreements. We did not fully meet the initial net acreage maintenance commitment with Total under the terms of our Barnett Shale joint venture agreement as of the December 31, 2012 measurement date and recorded a $26 million charge in impairments of fixed assets and other in our condensed consolidated statements of operations for an estimated shortfall of approximately 13,000 net acres. As of September 30, 2013, we revised our estimate of the net acreage shortfall as of December 31, 2012 to be approximately 14,000 net acres and anticipate making a cash payment of approximately $28 million to Total in the 2013 fourth quarter. Total has disputed our estimate of the shortfall, however, and the final resolution of this matter could exceed amounts we have accrued for maintenance of Total's acreage position.

Affiliate Commitments

Under the terms of our corporate revolving bank credit facility, certain of our subsidiaries, including our oilfield services companies, are not guarantors of the credit facility debt. Transactions under certain agreements between us and our non-guarantor subsidiaries could affect our EBITDA or indebtedness for purposes of our credit facility covenant calculations, but they would have no effect on the condensed consolidated financial statements because the transactions would be eliminated through consolidation. See Note 3 for discussion of our covenant calculations.

In October 2011, we entered into a services agreement with our wholly owned subsidiary, COO, under which we guarantee the utilization of a portion of COO's drilling rig and hydraulic fracturing fleets during the term of the agreement. Through October 2016, we are subject to monetary penalties if we do not operate a specific number of COO's drilling rigs or utilize a specific number of its hydraulic fracturing fleets. As of September 30, 2013, we had accrued a nominal amount for non-utilization pursuant to the agreement and eliminated its impact in consolidation. Any monetary penalties incurred in future periods would also be eliminated in consolidation.

Other Commitments

In April 2011, we entered into a master frac service agreement with our equity affiliate, FTS International, Inc. (FTS), which expires on December 31, 2014. Pursuant to this agreement, we are committed to enter into a predetermined number of backstop contracts, providing at least a 10% gross margin to FTS, if utilization of FTS fleets falls below a certain level. To date, we have not entered into any backstop contracts.

In July 2011, we agreed to invest $155 million in preferred equity securities of Sundrop Fuels, Inc., a privately held cellulosic biofuels company based in Longmont, Colorado. As of September 30, 2013, we had funded $115 million of our commitment. The remaining tranches of preferred equity investment will be scheduled around certain funding and operational milestones that are expected to be reached in the 2014 first quarter. See Note 9 for further discussion of this investment.

In December 2011, we sold Appalachia Midstream Services, L.L.C., a wholly owned subsidiary of our wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), to Access Midstream Partners, L.P. (NYSE:ACMP) for total consideration of $884 million. In addition, CMD committed to pay ACMP for any quarterly shortfall between the actual adjusted EBITDA from the assets sold and specified quarterly targets totaling $100 million in 2012 and $150 million in 2013. We recorded this guarantee at an estimated fair value of $27 million at the time of the sale. No payment was required for the Current Period or for 2012, and we recognized an $11 million gain in the Current Period associated with the release of this guarantee. The remaining $8 million fair value is included in other current liabilities on our condensed consolidated balance sheet as of September 30, 2013. We will release this liability in the 2013 fourth quarter if CMD is not required to make a payment under the guarantee. If payment is required, we will record the difference between the liability and the associated payment in earnings.

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging, financial or performance assurances to third parties on behalf of our wholly owned guarantor subsidiaries. These agreements may include future payment obligations or commitments regarding operational performance that effectively guarantee our subsidiaries' future performance.

In connection with divestitures, our purchase and sale agreements generally provide indemnification to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party or in regards to perfecting title to property. These indemnifications generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or cannot be quantified at the time of the consummation of a particular transaction.

Certain of our natural gas and oil properties are burdened by non-operating interests such as royalty and overriding royalty interests, including overriding royalty interests sold through our VPP transactions. As the holder of the working interest from which such interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to such interests. See Note 8 for further discussion of our VPP transactions.

5. Other Liabilities

Other current liabilities as of September 30, 2013 and December 31, 2012 are detailed below.

	September 30, 2013	December 31, 2012
	($ in millions)	
Revenues and royalties due others	$1,621	$1,337
Accrued natural gas, oil and NGL drilling and production costs	417	525
Joint interest prepayments received	472	749
Accrued compensation and benefits	276	225
Other accrued taxes	178	130
Accrued dividends	102	101
Other	559	674
Total other current liabilities	$3,625	$3,741

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Other long-term liabilities as of September 30, 2013 and December 31, 2012 are detailed below.

	September 30, 2013	December 31, 2012
	($ in millions)	
CHK Utica ORRI conveyance obligation[a]	$256	$275
CHK C-T ORRI conveyance obligation[b]	153	164
Financing obligations[c]	191	175
Mortgages payable[d]	—	56
Other	580	506
Total other long-term liabilities	$1,180	$1,176

(a) $23 million and $18 million of the total $279 million and $293 million obligations are recorded in other current liabilities as of September 30, 2013 and December 31, 2012, respectively. See Note 6 for further discussion of the transaction.

(b) $10 million and $14 million of the total $163 million and $178 million obligations are recorded in other current liabilities as of September 30, 2013 and December 31, 2012, respectively. See Note 6 for further discussion of the transaction.

(c) Consists primarily of an obligation related to 111 real estate surface properties in the Fort Worth area that we financed in 2009 for approximately $145 million and we 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 one of the properties in 2011 and four of the properties in the Current Period. See Note 18 for a discussion of the termination of this lease agreement on November 1, 2013.

(d) 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 had a floating interest rate of prime plus 275 basis points. In the Current Period, we prepaid the term loan in full without penalty. As of September 30, 2013, the building was classified as property and equipment held for sale on our condensed consolidated balance sheet.

6. Stockholders' Equity, Stock-Based Compensation, Performance Share Units and Noncontrolling Interests

Common Stock

The following is a summary of the changes in our common shares issued for the nine months ended September 30, 2013 and 2012:

	Nine Months Ended September 30, 2013	2012
	(in thousands)	
Shares issued as of January 1	666,468	660,888
Restricted stock issuances (net of forfeitures)[a]	684	5,758
Stock option exercises	321	309
Shares issued as of September 30	667,473	666,955

(a) In June 2013, we began granting restricted stock units (RSUs) in lieu of restricted stock awards (RSAs) to non-employee directors, and in the Current Quarter, we began granting RSUs in lieu of RSAs to employees. Shares of common stock underlying RSUs are issued when the units vest, whereas restricted shares of common stock are issued on the grant date of RSAs. We refer to RSAs and RSUs collectively as restricted stock.

19

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Preferred Stock

The following reflects the shares outstanding and liquidation preference of our preferred shares for the nine months ended September 30, 2013 and 2012:

	5.75%	5.75% (A)	4.50%	5.00% (2005B)	Total
Shares outstanding as of January 1, 2013 and 2012 and September 30, 2013 and 2012 (in thousands)	1,497	1,100	2,559	2,096	7,252
Liquidation preference per share	$1,000	$1,000	$100	$100	

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.

Dividends on our outstanding preferred stock are payable quarterly. We may pay dividends on our 5.00% Cumulative Convertible Preferred Stock (Series 2005B) and our 4.50% Cumulative Convertible Preferred Stock in cash, common stock or a combination thereof, at our option. Dividends on both series of our 5.75% Cumulative Convertible Non-Voting Preferred Stock are payable only in cash.

Stock-Based Compensation

Chesapeake's stock-based compensation program consists of restricted stock and stock options granted to employees and restricted stock granted to non-employee directors under our Long Term Incentive Plan. We recognize in our financial statements the cost of employee services received in exchange for awards of equity instruments, including restricted stock and stock options, based on the fair value of the equity instruments at the date of the grant. For employees, this value is amortized over the vesting period, which is generally three or four years from the date of grant. For directors, although restricted stock grants vest over three years, this value is expensed immediately as there is a non-substantive service condition for vesting. To the extent compensation cost relates to employees directly involved in the acquisition of natural gas and oil leasehold and exploration and development activities, such amounts are capitalized to natural gas and oil properties. Amounts not capitalized to natural gas and oil properties are recognized as general and administrative expenses, natural gas, oil and NGL production expenses, marketing, gathering and compression expenses or oilfield services expenses. 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,	
	2013	2012	2013	2012
	($ in millions)			
Natural gas and oil properties	$12	$18	$45	$55
General and administrative expenses	13	17	48	55
Natural gas, oil and NGL production expenses	5	6	17	18
Marketing, gathering and compression expenses	2	4	5	12
Oilfield services expenses	3	2	8	8
Total	$35	$47	$123	$148

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Restricted Stock

In the Current Period, we granted restricted stock to employees and non-employee directors. Restricted stock vests over a minimum of three years and the holder receives dividends or dividend equivalents on unvested shares. A summary of the changes in unvested shares during the nine months ended September 30, 2013 is presented below.

	Number of Unvested Restricted Shares (in thousands)	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2013	18,899	$23.72
Granted	9,053	$19.44
Vested	(9,553)	$23.31
Forfeited	(1,353)	$21.61
Unvested shares as of September 30, 2013	17,046	$21.85

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $187 million based on the stock price at the time of vesting.

As of September 30, 2013, there was $244 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of approximately 2.6 years.

The vesting of certain restricted stock grants could result 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 reductions in tax benefits related to restricted stock of a nominal amount, $14 million, $12 million and $19 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Stock Options

In the Current Period, we granted members of our senior management team stock options that will vest ratably over a three-year period. We also granted retention awards to certain officers of stock options that will vest one-third on each of the third, fourth and fifth anniversaries of the grant date. The stock option awards have an exercise price equal to the closing price of the Company's common stock on the grant date. Prior to 2006, we had granted stock options under several stock compensation plans which vested over a four-year period. Outstanding options expire ten years from the date of grant.

The following table provides information related to stock option activity for the nine months ended September 30, 2013:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)]
	(in thousands)			($ in millions)
Outstanding at January 1, 2013	481	$12.69	0.96	$2
Granted	5,264	$19.32		
Exercised	(345)	$10.81		
Expired	(94)	$19.43		
Outstanding at September 30, 2013	5,306	$19.27	7.18	$35
Exercisable at September 30, 2013	1,386	$18.79	2.34	$10

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

As of September 30, 2013, there was $19 million of total unrecognized compensation cost related to stock options. The cost is expected to be recognized over a weighted average period of approximately 2.8 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $2 million, a nominal amount, $2 million and $1 million, respectively. All amounts were recorded as adjustments to additional paid-in capital and deferred income taxes.

Performance Share Units

In January 2012 and 2013, we granted performance share units (PSUs) to senior management under our Long Term Incentive Plan that vest ratably over a three-year period. The 2012 awards are settled in cash on the first, second and third anniversary dates of the awards, and the 2013 awards are settled in cash on the third anniversary of the awards. The PSU awards include both an internal operational performance condition and an external market condition. The operational performance condition is a function of internal proved reserves growth and production growth. The market condition is a function of total shareholder return (TSR), and generally requires a Monte Carlo simulation to determine the fair value.

For PSUs granted in 2012, each of the TSR and operational payout components can range from 0% to 125% resulting in a maximum total payout of 250%. For PSUs granted in 2013, the TSR component can range from 0% to 125% and each of the two operational components can range from 0% to 62.5%; however, the maximum total payout is capped at 200% in all cases and at 100% in situations where the Company's absolute TSR is less than zero. The PSUs can only be settled in cash, so they are classified as a liability in our condensed consolidated financial statements and are measured at fair value as of the grant date and re-measured at fair value at the end of each reporting period. This fair value adjustment is recognized as compensation expense in the condensed consolidated statements of operations.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

The following table presents a summary of our PSU awards as of September 30, 2013:

	Units	Fair Value as of Grant-Date	Fair Value	Liability for Vested Amount
		($ in millions)		
2012 Awards [(a)]				
Payable 2014	278,084	$8	$10	$10
Payable 2015	834,246	23	29	28
Total 2012 Awards	1,112,330	$31	$39	$38
2013 Awards				
Payable 2016	1,637,601	$37	$54	$40

(a) In the Current Period, we paid $2 million related to 2012 PSU awards.

Noncontrolling Interests

Cleveland Tonkawa Financial Transaction. We formed CHK Cleveland Tonkawa, L.L.C. (CHK C-T) in March 2012 to continue development of a portion of our natural gas and oil assets in our Cleveland and Tonkawa plays. CHK C-T is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. In exchange for all of the common shares of CHK C-T, we contributed to CHK C-T approximately 245,000 net acres of leasehold and the existing wells within an area of mutual interest in the plays between the top of the Tonkawa and the top of the Big Lime formations covering Ellis and Roger Mills counties in western Oklahoma. In March 2012, in a private placement, third-party investors contributed $1.25 billion in cash to CHK C-T in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3.75% overriding royalty interest (ORRI) in the existing wells and up to 1,000 future net wells to be drilled on the contributed play leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK C-T limited liability company agreement (the CHK C-T LLC Agreement), as the holder of all the common shares and the sole managing member of CHK C-T, we maintain voting and managerial control of CHK C-T and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $225 million to the ORRI obligation and $1.025 billion to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheets. Pursuant to the CHK C-T LLC Agreement, CHK C-T is currently required to retain an amount of cash (measured quarterly) equal to (i) the next two quarters of preferred dividend payments plus (ii) its projected operating funding shortfall for the next six months (projected operating funding shortfall requirement ends on December 31, 2013). The amount so retained, approximately $38 million as of September 30, 2013, is reflected as restricted cash on our condensed consolidated balance sheet.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 6% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK C-T, we may, at our sole discretion and election at any time after March 31, 2014, distribute certain excess cash of CHK C-T, as determined in accordance with the CHK C-T LLC Agreement. Any such optional distribution of excess cash is allocated 75% to the preferred shares (which is applied toward redemption of the preferred shares) and 25% to the common shares unless we have not met our drilling commitment at such time, in which case an optional distribution would be allocated 100% to the preferred shares (and applied toward redemption thereof). We may also, at our sole discretion and election, in accordance with the CHK C-T LLC Agreement, cause CHK C-T to redeem all or a portion of the CHK C-T preferred shares for cash. The preferred shares may be redeemed at a valuation equal to the greater of a 9%

internal rate of return or a return on investment of 1.35x, in each case inclusive of dividends paid through redemption at the rate of 6% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to March 31, 2019, the optional redemption valuation will increase to provide a 15% internal rate of return to the investors. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of September 30, 2013, the redemption price and the liquidation preference were each $1,260 per preferred share.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

We have committed to drill and complete, for the benefit of CHK C-T in the area of mutual interest, a minimum of 37.5 net wells per six-month period through 2013, inclusive of wells drilled in 2012, and 25 net wells per six-month period in 2014 through 2016, up to a minimum cumulative total of 300 net wells. If we fail to meet the then-current cumulative drilling commitment in any six-month period, any optional cash distributions would be distributed 100% to the investors. If we fail to meet the then-current cumulative drilling commitment in two consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would increase by 3% per annum. In addition, if we fail to meet the then-current cumulative drilling commitment in four consecutive six-month periods, the then-applicable internal rate of return to investors at redemption would be increased by an additional 3% per annum. Any such increase in the internal rate of return would be effective only until the end of the first succeeding six-month period in which we have met our then-current cumulative drilling commitment. CHK C-T is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. Under the development agreement, approximately 73 and 58 qualified net wells were added in the Current Period and the Prior Period, respectively. As of September 30, 2013, we had met our 2013 drilling commitment associated with the CHK C-T transaction.

The CHK C-T investors' right to receive, proportionately, a 3.75% ORRI in the contributed wells and up to 1,000 future net wells on our contributed leasehold is subject to an increase to 5% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs from 2012 through the first quarter of 2025. However, in no event would we deliver to investors more than a total ORRI of 3.75% in existing wells and 1,000 future net wells. If at any time CHK C-T holds fewer net acres than would enable us to drill all then-remaining net wells on 160-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs once we have drilled a minimum of 867 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. Under the ORRI obligation, we delivered an ORRI in approximately 80 net wells in the Current Period and 50 net wells in the Prior Period. While operations began on April 1, 2012, all wells completed since January 1, 2012 are credited to the ORRI obligation of 1,000 future net wells. Through September 30, 2013, we were on target to meet the 2013 ORRI conveyance commitment associated with the CHK C-T transaction.

As of September 30, 2013 and December 31, 2012, $1.015 billion of noncontrolling interests on our condensed consolidated balance sheets was attributable to CHK C-T. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, income of $19 million, $19 million, $56 million and $38 million, respectively, was attributable to the noncontrolling interests of CHK C-T.

Utica Financial Transaction. We formed CHK Utica, L.L.C. (CHK Utica) in October 2011 to develop a portion of our Utica Shale natural gas and oil assets. CHK Utica is an unrestricted subsidiary under our corporate credit facility agreement and is not a guarantor of, or otherwise liable for, any of our indebtedness or other liabilities, including indebtedness under our indentures. In exchange for all of the common shares of CHK Utica, we contributed to CHK Utica approximately 700,000 net acres of leasehold and the existing wells within an area of mutual interest in the Utica Shale play covering 13 counties located primarily in eastern Ohio. During November and December 2011, in private placements, third-party investors contributed $1.25 billion in cash to CHK Utica in exchange for (i) 1.25 million preferred shares, and (ii) our obligation to deliver a 3% ORRI in 1,500 net wells to be drilled on certain of our Utica Shale leasehold. Subject to customary minority interest protections afforded the investors by the terms of the CHK Utica limited liability company agreement (the CHK Utica LLC Agreement), as the holder of all the common shares and the sole managing member of CHK Utica, we maintain voting and managerial control of CHK Utica and therefore include it in our condensed consolidated financial statements. Of the $1.25 billion of investment proceeds, we allocated $300 million to the ORRI obligation and $950 million to the preferred shares based on estimates of fair values. The remaining ORRI obligation is included in other current and long-term liabilities and the preferred shares are included in noncontrolling interests on our condensed consolidated balance sheets. Pursuant to the CHK Utica LLC Agreement, CHK Utica is required to retain a cash balance equal to the next two quarters of preferred dividend payments. The amount reserved for paying such dividends, approximately $37 million, was reflected as restricted cash on our condensed consolidated balance sheet as of September 30, 2013. In addition, pursuant to the CHK Utica LLC Agreement, with respect to any divestiture proceeds as defined by the agreement, CHK Utica is required to separately account for, and dedicate all of such divestiture proceeds to either (i) capital expenditures made by CHK Utica in connection with its assets or (ii) the redemption of CHK Utica preferred shares. As of December 31, 2012, we held $155 million received from divestitures defined by the agreement as restricted cash in other long-term assets on our condensed consolidated balance sheet. In the Current Period, we used all of the $155 million for CHK Utica capital expenditures.

Dividends on the preferred shares are payable on a quarterly basis at a rate of 7% per annum based on $1,000 per share. This dividend rate is subject to increase in limited circumstances in the event that, and only for so long as, any dividend amount is not paid in full for any quarter. As the managing member of CHK Utica, we may, at our sole discretion and election at any time after December 31, 2013, distribute certain excess cash of CHK Utica, as determined in accordance with the CHK Utica LLC Agreement. Any such optional distribution of excess cash is allocated 70% to the preferred shares (which is applied toward redemption of the preferred shares) and 30% to the common shares. We may also, at our sole discretion and election, in accordance with the CHK Utica LLC Agreement, cause CHK Utica to redeem the CHK Utica preferred shares for cash, in whole or in part. The preferred shares may be redeemed at a valuation equal to the greater of a 10% internal rate of return or a return on investment of 1.4x, in each case inclusive of dividends paid at the rate of 7% per annum and optional distributions made through the applicable redemption date. In the event that redemption does not occur on or prior to October 31, 2018, the optional redemption valuation will increase to provide the investors the greater of a 17.5% internal rate of return or a return on investment of 2.0x. The preferred shares can be redeemed on a pro-rata basis in accordance with the then-applicable redemption valuation formula. As of September 30, 2013, the redemption price and the liquidation preference were each approximately $1,270 per preferred share.

We have committed to drill and complete, for the benefit of CHK Utica in the area of mutual interest, a minimum of 50 net wells per year from 2012 through 2016, up to a minimum cumulative total of 250 net wells. CHK Utica is responsible for all capital and operating costs of the wells drilled for the benefit of the entity. If we fail to meet the then-current drilling commitment in any year, we must pay CHK Utica $5 million for each well we are short of such drilling commitment. CHK Utica also receives its proportionate share of the benefit of the drilling carry associated with our joint venture with Total in the Utica Shale. See Note 8 for further discussion of the joint venture. Under the development agreement, approximately 86 and 40 qualified net wells were added in the Current Period and Prior Period, respectively. As of September 30, 2013, we had met our 2013 drilling commitment associated with the CHK Utica transaction.

The CHK Utica investors' right to receive, proportionately, a 3% ORRI in the first 1,500 net wells drilled on our Utica Shale leasehold is subject to an increase to 4% on net wells earned in any year following a year in which we do not meet our net well commitment under the ORRI obligation, which runs from 2012 through 2023. However, in no event would we deliver to investors more than a total ORRI of 3% in 1,500 net wells. If at any time we hold fewer net acres than would enable us to drill all then-remaining net wells on 150-acre spacing, the investors have the right to require us to repurchase their right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs. We retain the right to repurchase the investors' right to receive ORRIs in the remaining net wells at the then-current fair market value of such remaining ORRIs once we have drilled a minimum of 1,300 net wells. The obligation to deliver future ORRIs has been recorded as a liability which will be settled through the future conveyance of the underlying ORRIs to the investors on a net-well basis, at which time the associated liability will be reversed and the sale of the ORRIs reflected as an adjustment to the capitalized cost of our natural gas and oil properties. Under the ORRI obligation, we delivered an ORRI in approximately 100 new net wells in the Current Period and 31 net wells in the Prior Period. We did not meet our ORRI commitment in 2012. The ORRI increased to 4% for wells earned in 2013, and the ultimate number of wells in which we must assign an interest will be reduced accordingly. Through September 30, 2013, we were on target to meet the 2013 ORRI conveyance commitment associated with the CHK Utica transaction.

As of September 30, 2013 and December 31, 2012, $807 million and $950 million of noncontrolling interests on our condensed consolidated balance sheets, respectively, were attributable to CHK Utica. For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, income of approximately $18 million, $22 million, $60 million and $66 million, respectively, was attributable to the noncontrolling interests of CHK Utica. In the Current Period, we purchased approximately 190,000 preferred shares of CHK Utica from existing investors for approximately $212 million, or approximately $1,115 per share plus accrued dividends, reducing the amount of outstanding preferred shares held by third-party investors by approximately 15%. The difference between the cash paid for the preferred shares and the carrying value of the noncontrolling interest acquired of $69 million is reflected in retained earnings and as a reduction to net income available to common stockholders for purposes of our EPS computations.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Chesapeake Granite Wash Trust. In November 2011, Chesapeake Granite Wash Trust (the "Trust") sold 23,000,000 common units representing beneficial interests in the Trust at a price of $19.00 per common unit in its initial public offering. The common units are listed on the New York Stock Exchange and trade under the symbol "CHKR". We own 12,062,500 common units and 11,687,500 subordinated units, which in the aggregate represent an approximate 51% beneficial interest in the Trust. The Trust has a total of 46,750,000 units outstanding.

In connection with the initial public offering of the Trust, we conveyed royalty interests to the Trust that entitle the Trust to receive (i) 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) that we receive from the production of hydrocarbons from 69 producing wells, and (ii) 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) in 118 development wells that have been or will be drilled on approximately 45,400 gross acres (29,000 net acres) in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma. Pursuant to the terms of a development agreement with the Trust, we are obligated to drill, or cause to be drilled, the development wells at our own expense prior to June 30, 2016, and the Trust will not be responsible for any costs related to the drilling of the development wells or any other operating or capital costs of the Trust properties. In addition, we granted to the Trust a lien on our remaining interests in the undeveloped properties that are subject to the development agreement in order to secure our drilling obligation to the Trust, although the maximum amount that may be recovered by the Trust under such lien could not exceed $263 million initially and is proportionately reduced as we fulfill our drilling obligation over time. As of September 30, 2013, we had drilled or caused to be drilled approximately 80 development wells, as calculated under the development agreement, and the maximum amount recoverable under the drilling support lien was approximately $85 million.

The subordinated units we hold in the Trust are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is not less than the applicable subordination threshold for such quarter. If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. In exchange for agreeing to subordinate a portion of our Trust units, and in order to provide additional financial incentive to us to satisfy our drilling obligation and perform operations on the underlying properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on the Trust units in any quarter exceeds the applicable incentive threshold for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following our satisfaction of our drilling obligation with respect to the development wells, the subordinated units will automatically convert into common units on a one-for-one basis and our right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share in the Trust's distributions on a pro rata basis.

For the Current Period and Prior Period, the Trust declared and paid the following distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
March 2013 - May 2013	August 29, 2013	$0.6900	$0.1432
December 2012 - February 2013	May 31, 2013	$0.6900	$0.3010
September 2012 - November 2012	March 1, 2013	$0.6700	$0.3772
March 2012 - May 2012	August 30, 2012	$0.6100	$0.4819
December 2011 - February 2012	May 31, 2012	$0.6588	$0.6588
September 2011 - November 2011	March 1, 2012	$0.7277	$0.7277

We have determined that the Trust constitutes a VIE and that Chesapeake is the primary beneficiary. As a result, the Trust is included in our condensed consolidated financial statements. As of September 30, 2013 and December 31, 2012, $323 million and $356 million of noncontrolling interests on our condensed consolidated balance sheets, respectively, were attributable to the Trust. For the Current Quarter, Prior Quarter, Current Period and Prior Period, income of approximately $2 million, $1 million, $14 million and $28 million, respectively, was attributable to the Trust's noncontrolling interests in our condensed consolidated statements of operations. See Note 10 for further discussion of VIEs.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Wireless Seismic, Inc. We have a controlling 51% equity interest in Wireless Seismic, Inc. (Wireless), a privately owned company engaged in research, development and eventual production of wireless seismic systems and any related technology that deliver seismic information obtained from standard geophones in real time to laptop and desktop computers. As of September 30, 2013 and December 31, 2012, $7 million and $5 million of noncontrolling interests on our condensed consolidated balance sheets, respectively, were attributable to Wireless. In the Current Quarter and Current Period, losses of $1 million and $3 million, respectively, were attributable to noncontrolling interests of Wireless in our condensed consolidated statement of operations.

7. Derivative and Hedging Activities

Natural Gas, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective prices to be received for our production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives. As of September 30, 2013 and December 31, 2012, our natural gas and oil derivative instruments consisted 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.
- Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call option, no payment is due from either party.
- Swaptions: Chesapeake sells call swaptions in exchange for a premium that allows a counterparty, on a specific date, to enter into a fixed-price swap for a certain period of time.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our natural gas basis protection swaps 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. Our oil basis protection swaps 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.
- 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 strike price.

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.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

The estimated fair values of our natural gas and oil derivative instrument assets (liabilities) as of September 30, 2013 and December 31, 2012 are provided below.

	September 30, 2013		December 31, 2012	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Natural gas (tbtu):				
Fixed-price swaps	341	$96	49	$24
Call options	193	(219)	193	(240)
Call swaptions	12	—	—	—
Basis protection swaps	79	(2)	111	(15)
Three-way collars	36	4	—	—
Total natural gas	661	(121)	353	(231)
Oil (mmbbl):				
Fixed-price swaps	31.6	(94)	28.1	68
Call options	65.6	(368)	73.8	(748)
Call swaptions	5.3	(1)	5.3	(13)
Basis protection swaps	0.5	1	5.5	—
Total oil	103.0	(462)	112.7	(693)
Total estimated fair value		$(583)		$(924)

Pursuant to accounting guidance, 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 and locked-in gains and losses of settled designated derivative contracts, are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized in natural gas, oil and NGL sales. Changes in the fair value of derivatives not designated as cash flow hedges that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within natural gas, oil and NGL sales. As of September 30, 2013, we did not have any natural gas or oil derivatives that were designated as cash flow hedges. Therefore, changes in the fair value of these derivatives are reported in the condensed consolidated statement of operations. See further discussion below under Cash Flow Hedges.

The components of natural gas, oil and NGL 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,	
	2013	2012	2013	2012
	($ in millions)			
Natural gas, oil and NGL sales	$1,839	$1,464	$5,303	$3,798
Gains (losses) on natural gas, oil and NGL derivatives	(253)	(27)	141	824
Total natural gas, oil and NGL sales	$1,586	$1,437	$5,444	$4,622

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Hedging Facility

We have a multi-counterparty secured hedging facility with 16 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. As of September 30, 2013, we had hedged under the facility 1.2 tcfe of our future production with price derivatives and 0.1 tcfe with basis derivatives. The multi-counterparty facility allows us to enter into cash-settled natural gas, oil and NGL price and basis derivatives with the counterparties. Our obligations under the multi-counterparty facility are secured by proved reserves, the value of which must cover the fair value of the transactions outstanding under the facility by at least 1.65 times at semi-annual collateral dates and 1.30 times in between those dates, and guarantees by certain subsidiaries that also guarantee our corporate revolving bank credit facility, indentures, term loan and equipment master lease agreements. 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 derivatives. In addition, there are volume-based sub-limits for natural gas, oil and NGL derivative instruments. Chesapeake has significant flexibility with regard to releases and/or substitutions of pledged reserves, provided that certain requirements are met including maintaining specified collateral coverage ratios as well as maintaining credit ratings with either of the designated rating agencies at or above current levels. The facility does not have a maturity date. Counterparties to the agreement have the right to cease entering into derivative instruments with the Company on a prospective basis as long as obligations associated with any existing transactions in the facility continue to be satisfied in accordance with the terms of the agreement.

Interest Rate Derivatives

To mitigate a portion of 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, 2013 and December 31, 2012, our interest rate derivative instruments consisted of 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.

The notional amount and the estimated fair value of our interest rate derivative liabilities as of September 30, 2013 and December 31, 2012 are provided below.

	September 30, 2013		December 31, 2012	
	Notional Amount	Fair Value	Notional Amount	Fair Value
		($ in millions)		
Interest rate swaps	$2,500	$(88)	$1,050	$(35)

29

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Realized and unrealized 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,	
	2013	2012	2013	2012
	($ in millions)			
Interest expense on senior notes	$180	$187	$560	$546
Interest expense on credit facilities	8	13	30	51
Interest expense on term loans	29	112	87	173
(Gains) losses on interest rate derivatives	(3)	(2)	51	(4)
Amortization of loan discount, issuance costs and other	21	24	70	67
Capitalized interest	(195)	(298)	(634)	(770)
Total interest expense	$40	$36	$164	$63

We have terminated certain fair value hedges related to senior notes. Gains and losses related to these terminated hedges will be amortized as an adjustment to interest expense over the remaining term of the related senior notes. Over the next seven years, we will recognize $14 million in net gains related to such transactions.

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of 1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $5 million as of September 30, 2013. The euro-denominated debt in long-term debt has been adjusted to $465 million as of September 30, 2013 using an exchange rate of $1.3527 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, we net the value of our 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 respective balance sheet dates. The derivative settlement amounts are not due until the month in which the related hedged transaction occurs. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivative is deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying condensed consolidated statements of cash flows.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

The following table presents the fair value and location of each classification of derivative instrument disclosed in the condensed consolidated balance sheets as of September 30, 2013 and December 31, 2012 on a gross basis without regard to same-counterparty netting:

	Balance Sheet Location	Fair Value September 30, 2013 ($ in millions)	December 31, 2012
Asset Derivatives:			
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	$115	$110
Commodity contracts	Long-term derivative instruments	11	5
Total		126	115
Liability Derivatives:			
Designated as hedging instruments:			
Foreign currency contracts	Long-term derivative instruments	(5)	(20)
Total		(5)	(20)
Not designated as hedging instruments:			
Commodity contracts	Short-term derivative instruments	(265)	(157)
Commodity contracts	Long-term derivative instruments	(444)	(882)
Interest rate contracts	Short-term derivative instruments	(9)	—
Interest rate contracts	Long-term derivative instruments	(79)	(35)
Total		(797)	(1,074)
Total derivative instruments		$(676)	$(979)

All of the Company’s derivative positions are subject to netting arrangements which provide for offsetting of asset and liability positions, as well as related cash collateral if applicable. Such netting arrangements generally do not have restrictions. Under such netting arrangements, the Company offsets the fair value of derivative instruments with cash collateral received or paid for those contracts executed with the same counterparty, which reduces the Company’s total assets and liabilities. As of September 30, 2013 and December 31, 2012, we did not have any cash collateral balances for these derivatives.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

The following tables present the netting offsets of derivative assets and liabilities as of September 30, 2013 and December 31, 2012:

	September 30, 2013			
	Derivative Assets		Derivative Liabilities	
	Short-Term	Long-Term	Short-Term	Long-Term
	($ in millions)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$115	$11	$(265)	$(444)
Gross amounts offset in the condensed consolidated balance sheet	(104)	(9)	104	9
Net amounts of assets (liabilities) presented in the condensed consolidated balance sheet	11	2	(161)	(435)
Interest Rate Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	(9)	(79)
Gross amounts offset in the condensed consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the condensed consolidated balance sheet	—	—	(9)	(79)
Foreign Currency Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(5)
Gross amounts offset in the condensed consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the condensed consolidated balance sheet	—	—	—	(5)
Total derivatives as reported	$11	$2	$(170)	$(519)

	December 31, 2012			
	Derivative Assets		Derivative Liabilities	
	Short-Term	Long-Term	Short-Term	Long-Term
	($ in millions)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	$110	$5	$(157)	$(882)
Gross amounts offset in the consolidated balance sheet	(52)	(3)	52	3
Net amounts of assets (liabilities) presented in the consolidated balance sheet	58	2	(105)	(879)
Interest Rate Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(35)
Gross amounts offset in the consolidated balance sheet	—	—	—	—
Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	—	—	(35)
Foreign Currency Contracts:				
Gross amounts of recognized assets (liabilities)	—	—	—	(20)
Gross amounts offset in the consolidated balance sheet	—	—	—	—

Net amounts of assets (liabilities) presented in the consolidated balance sheet	—	—	—	(20)
Total derivatives as reported	$58	$2	$(105)	$(934)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

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

Fair Value Hedges

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. We have elected not to designate any of our qualifying interest rate derivatives as fair value hedges. Therefore, changes in the fair value of all of our interest rate derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported in the condensed consolidated statements of operations within interest expense.

The following table presents the gain (loss) recognized in the condensed consolidated statements of operations for terminated instruments that were designated as fair value derivatives:

		Three Months Ended September 30,		Nine Months Ended September 30,	
Fair Value Derivatives	Location of Gain (Loss)	2013	2012	2013	2012
		($ in millions)			
Interest rate contracts	Interest expense	$1	$2	$4	$6

Cash Flow Hedges

A reconciliation of the changes of accumulated other comprehensive income (loss) in the condensed consolidated statements of stockholders' equity related to our cash flow hedges is presented below.

	Three Months Ended September 30,			
	2013		2012	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(286)	$(178)	$(306)	$(190)
Net change in fair value	3	2	4	3
(Gains) losses reclassified to income	3	2	(9)	(6)
Balance, end of period	$(280)	$(174)	$(311)	$(193)

	Nine Months Ended September 30,			
	2013		2012	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(304)	$(189)	$(287)	$(178)
Net change in fair value	3	2	4	3
(Gains) losses reclassified to income	21	13	(28)	(18)
Balance, end of period	$(280)	$(174)	$(311)	$(193)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Approximately $166 million of the $174 million of accumulated other comprehensive loss as of September 30, 2013 represents the net deferred loss associated with commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. These amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of September 30, 2013, we expect to transfer approximately $22 million of net loss included in accumulated other comprehensive income to net income (loss) during the next 12 months. The remaining amount will be transferred by December 31, 2022. As of September 30, 2013, none of our open commodity derivative instruments were designated as cash flow hedges.

The following table presents the pre-tax gain (loss) recognized in, and reclassified from, accumulated other comprehensive income (AOCI) related to instruments designated as cash flow derivatives:

Cash Flow Derivatives	Location of Gain (Loss)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
		($ in millions)			
Gain (Loss) Recognized in AOCI (Effective Portion):					
Foreign currency contracts	AOCI	$3	$4	$3	$4
		$3	$4	$3	$4
Gain (Loss) Reclassified from AOCI (Effective Portion):					
Commodity contracts	Natural gas, oil and NGL sales	$(3)	$9	$(21)	$28
		$(3)	$9	$(21)	$28

Undesignated Derivatives

The following table presents the gain (loss) recognized in the condensed consolidated statements of operations for instruments not designated as either cash flow or fair value hedges:

Derivative Contracts	Location of Gain (Loss)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
		($ in millions)			
Commodity contracts	Natural gas, oil and NGL sales	$(250)	$(36)	$162	$796
Interest rate contracts	Interest expense	2	—	(55)	(2)
Total		$(248)	$(36)	$107	$794

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment-grade and deemed by management to be competent and competitive market makers, and we attempt to limit our exposure to non-performance by any single counterparty. As of September 30, 2013, our natural gas, oil and interest rate derivative instruments were spread among 15 counterparties. Additionally, counterparties to our multi-counterparty secured hedging facility described previously are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our natural gas, oil and NGL derivatives.

34

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

8. Divestitures
Natural Gas and Oil Properties
Under full cost accounting rules, we account for the sale of natural gas and oil properties as an adjustment to capitalized costs, with no recognition of gain or loss as the sales typically do not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves. In conjunction with certain sales, affiliates of our former Chief Executive Officer, Aubrey K. McClendon, have sold interests in the same properties and on the same terms as those that applied to the interests sold by the Company, and the net proceeds were paid to the sellers based on their respective ownership. These interests were acquired through the Founder Well Participation Program, which provides Mr. McClendon a contractual right to participate and invest as a working interest owner (with up to a 2.5% working interest) in new wells drilled on the Company's leasehold through June 2014.
In the Current Quarter, we sold assets in the Haynesville Shale to EXCO Operating Company, LP (EXCO) for net proceeds of approximately $257 million. We may receive up to an additional $32 million of net proceeds pursuant to customary post-closing adjustments. The assets sold included our operated and non-operated interests in approximately 9,600 net acres in DeSoto and Caddo parishes, Louisiana.
In the Current Quarter, we sold assets in the northern Eagle Ford Shale to EXCO for net proceeds of approximately $617 million. In the Current Quarter, we received approximately $4 million of net proceeds for customary post-closing adjustments and may receive up to an additional $64 million of net proceeds pursuant to further customary post-closing adjustments. The assets sold included approximately 55,000 net acres in Zavala, Dimmit, La Salle and Frio counties, Texas.
In the Prior Quarter, we sold producing assets in the Midland Basin portion of the Permian Basin to affiliates of Houston-based EnerVest, Ltd. for approximately $376 million in cash
In the Prior Quarter, we sold approximately 72,000 net acres of noncore leasehold in the Utica Shale play in Ohio to affiliates of EnerVest, Ltd. for approximately $358 million in cash.
In the Prior Period, we sold approximately 60,000 net acres of leasehold in the Texoma Woodford play in Bryan, Carter, Johnston and Marshall counties, Oklahoma to XTO Energy Inc., a subsidiary of Exxon Mobil Corporation (NYSE:XOM), for net proceeds of approximately $572 million.
During the Current Period and the Prior Period, we received proceeds of approximately $800 million and $180 million, respectively, from various other divestitures of natural gas and oil properties.
Joint Ventures
On June 28, 2013, we completed a strategic joint venture with Sinopec International Petroleum Exploration and Production Corporation (Sinopec) in which Sinopec purchased a 50% undivided interest in approximately 850,000 acres in the Mississippi Lime play in northern Oklahoma (425,000 acres net to Sinopec). The total consideration for the transaction was approximately $1.020 billion in cash, of which approximately $949 million of net proceeds, or 93%, was received upon closing. We also received an additional $90 million at closing related to closing adjustments for activity between the effective date and closing date of the transaction. We may receive up to an additional $71 million of net proceeds pursuant to customary post-closing adjustments. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

As of September 30, 2013, we had entered into eight significant joint ventures with other leading energy companies pursuant to which we sold a portion of our leasehold, producing properties and other assets located in eight different resource plays and received cash of $8.0 billion and commitments by our counterparties to pay our share of future drilling and completion costs of $9.0 billion. In each of these joint ventures, Chesapeake serves as the operator and conducts all drilling, completion and operations, the majority of leasing and, in certain transactions, marketing activities for the project. The carries paid by a joint venture partner are for a specified percentage of our drilling and completion costs. In addition, a joint venture partner is responsible for its proportionate share of drilling and completion costs as a working interest owner. We bill our joint venture partners for their drilling carries at the same time we bill them and other joint working interest owners for their share of drilling costs as they are incurred. For accounting purposes, initial cash proceeds from these joint venture transactions were reflected as a reduction of natural gas and oil properties with no gain or loss recognized. The transactions are detailed below.

Primary Play	Joint Venture Partner[a]	Joint Venture Date	Interest Sold	Initial Proceeds[b]		Total Drilling Carries		Total Initial Proceeds and Drilling Carries	Drilling Carries Remaining[c]
				($ in millions)					
Mississippi Lime	Sinopec	June 2013	50.0%	$949	(d)	$—		$949	$—
Utica	TOT	December 2011	25.0%	610		1,422	(e)	2,032	714
Niobrara	CNOOC	February 2011	33.3%	570		697	(f)	1,267	233
Eagle Ford	CNOOC	November 2010	33.3%	1,120		1,080		2,200	—
Barnett	TOT	January 2010	25.0%	800		1,403		2,203	—
Marcellus	STO	November 2008	32.5%	1,250		2,125		3,375	—
Fayetteville	BP	September 2008	25.0%	1,100		800		1,900	—
Haynesville & Bossier	FCX	July 2008	20.0%	1,650		1,508		3,158	—
				$8,049		$9,035		$17,084	$947

(a) Joint venture partners include Sinopec International Petroleum Exploration and Production (Sinopec), Total S.A. (TOT), CNOOC Limited (CNOOC), Statoil (STO), BP America (BP) and Freeport-McMoRan Copper & Gold (FCX), formerly known as Plains Exploration & Production Company.
(b) Excludes closing and post-closing adjustments.
(c) As of September 30, 2013.
(d) Excludes $71 million of net proceeds (or 7% of the total transaction) expected to be received pursuant to certain customary post-closing adjustments and approximately $90 million received at closing for closing adjustments.
(e) The Utica drilling carries cover 60% of our drilling and completion costs for Utica wells drilled and must be used by December 2018. We expect to fully utilize these drilling carry commitments prior to expiration. See Note 4 for further discussion of the Utica drilling carries.
(f) The Niobrara drilling carries cover 67% of our drilling and completion costs for Niobrara wells drilled and must be used by December 2014. We expect to fully utilize these drilling carry commitments prior to expiration.

During the Current Period and the Prior Period, our drilling and completion costs included the benefit of approximately $669 million and $655 million, respectively, in drilling and completion carries paid by our joint venture partners.

During the Current Period and the Prior Period, we sold interests in additional leasehold we acquired in the Marcellus, Barnett and Utica Shale plays to our joint venture partners TOT and STO for approximately $48 million and $228 million, respectively.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Volumetric Production Payments

From time to time, we have sold certain of our producing assets which are located in more mature producing regions through the sale of VPPs. A VPP is a limited-term overriding royalty interest in natural gas and oil reserves that (i) entitles the purchaser to receive scheduled production volumes over a period of time from specific lease interests; (ii) is free and clear of all associated future production costs and capital expenditures; (iii) is nonrecourse to the seller (i.e., the purchaser’s only recourse is to the reserves acquired); (iv) transfers title of the reserves to the purchaser; and (v) allows the seller to retain all production beyond the specified volumes, if any, after the scheduled production volumes have been delivered. For all of our VPP transactions, we have novated hedges to each of the respective VPP buyers and such hedges covered all VPP volumes sold. If contractually scheduled volumes exceed the actual volumes produced from the VPP wellbores that are attributable to the ORRI conveyed, either the shortfall will be made up from future production from these wellbores (or, at our option, from our retained interest in the wellbores) through an adjustment mechanism or the initial term of the VPP will be extended until all scheduled volumes, to the extent produced, are delivered from the VPP wellbores to the VPP buyer. We retain drilling rights on the properties below currently producing intervals and outside of producing wellbores.

As the operator of the properties from which the VPP volumes have been sold, we have the responsibility to bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining the cost center ceiling for impairment purposes and in determining our standardized measure. Pursuant to SEC guidelines, the estimates used for purposes of determining the cost center ceiling and the standardized measure are based on current costs. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all.

For accounting purposes, cash proceeds from the sale of VPPs were reflected as a reduction of natural gas and oil properties with no gain or loss recognized, and our proved reserves were reduced accordingly. We have also committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Our outstanding VPPs consist of the following:

				Volume Sold			
VPP #	Date of VPP	Division	Proceeds	Natural Gas	Oil	NGL	Total
			($ in millions)	(bcf)	(mmbbl)	(mmbbl)	(bcfe)
10	March 2012	Anadarko Basin Granite Wash	$744	87	3.0	9.2	160
9	May 2011	Mid-Continent	853	138	1.7	4.8	177
8	September 2010	Barnett Shale	1,150	390	—	—	390
6	February 2010	East Texas and Texas Gulf Coast	180	44	0.3	—	46
5	August 2009	South Texas	370	67	0.2	—	68
4	December 2008	Anadarko and Arkoma Basins	412	95	0.5	—	98
3	August 2008	Anadarko Basin	600	93	—	—	93
2	May 2008	Texas, Oklahoma and Kansas	622	94	—	—	94
1	December 2007	Kentucky and West Virginia	1,100	208	—	—	208
			$6,031	1,216	5.7	14.0	1,334

The volumes produced on behalf of our VPP buyers for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period were as follows:

	Three Months Ended September 30, 2013			
VPP #	Natural Gas	Oil	NGL	Total
	(bcf)	(mbbl)	(mbbl)	(bcfe)
10	3.7	131.0	371.9	6.7
9	4.1	52.3	140.3	5.2
8	16.6	—	—	16.6
6	1.2	6.0	—	1.2
5	1.9	6.7	—	1.9
4	2.4	13.9	—	2.6
3	2.0	—	—	2.0
2	2.6	—	—	2.6
1	3.5	—	—	3.5
	38.0	209.9	512.2	42.3

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

	Three Months Ended September 30, 2012			
VPP #	Natural Gas (bcf)	Oil (mbbl)	NGL (mbbl)	Total (bcfe)
10	5.3	206.0	503.7	9.5
9	4.5	60.8	158.0	5.8
8	19.4	—	—	19.4
7	0.2	147.3	—	1.0
6	1.3	6.0	—	1.4
5	2.2	6.6	—	2.2
4	2.9	15.8	—	3.0
3	2.3	—	—	2.3
2	2.8	—	—	2.8
1	3.7	—	—	3.7
	44.6	442.5	661.7	51.1

	Nine Months Ended September 30, 2013			
VPP #	Natural Gas (bcf)	Oil (mbbl)	NGL (mbbl)	Total (bcfe)
10	11.4	426.0	1,158.6	20.9
9	12.5	162.5	433.0	16.0
8	51.6	—	—	51.6
6	3.6	18.0	—	3.7
5	5.7	19.0	—	5.8
4	7.8	42.7	—	8.1
3	6.2	—	—	6.2
2	7.9	—	—	7.9
1	10.9	—	—	10.9
	117.6	668.2	1,591.6	131.1

	Nine Months Ended September 30, 2012			
VPP #	Natural Gas (bcf)	Oil (mbbl)	NGL (mbbl)	Total (bcfe)
10	13.5	547.0	1,286.6	24.5
9	14.0	191.0	490.6	18.1
8	61.1	—	—	61.1
7	0.4	490.3	—	3.4
6	4.1	18.0	—	4.2
5	6.8	21.2	—	6.9
4	9.0	48.7	—	9.3
3	7.1	—	—	7.1
2	8.6	—	—	8.6
1	11.5	—	—	11.5
	136.1	1,316.2	1,777.2	154.7

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

The volumes remaining to be delivered on behalf of our VPP buyers as of September 30, 2013 were as follows:

		Volume Remaining as of September 30, 2013			
VPP #	Term Remaining (in months)	Natural Gas (bcf)	Oil (mmbbl)	NGL (mmbbl)	Total (bcfe)
10	101	57.1	1.8	6.3	106.1
9	89	89.5	1.1	3.1	114.4
8	23	112.0	—	—	112.0
6	76	22.6	0.2	—	23.6
5	40	18.7	0.1	—	19.0
4	39	27.2	0.1	—	28.1
3	70	33.0	—	—	33.0
2	67	23.1	—	—	23.1
1	111	109.0	—	—	109.0
		492.2	3.3	9.4	568.3

In September 2012, to facilitate the sales process associated with our Permian Basin divestiture packages, we purchased the remaining reserves from our Permian Basin VPP (VPP #7), originally sold in June 2010, for $313 million. The reserves purchased totaled 28 bcfe and were subsequently sold to the buyers of our Permian Basin assets.

9. Investments

A summary of our investments, including our approximate ownership percentage as of September 30, 2013, is presented below.

			Carrying Value	
	Approximate Ownership %	Accounting Method	September 30, 2013	December 31, 2012
			($ in millions)	
FTS International, Inc.	30%	Equity	$318	$298
Chaparral Energy, Inc.	20%	Equity	145	141
Sundrop Fuels, Inc.	50%	Equity	97	111
Twin Eagle Resource Management, LLC	30%	Equity	30	34
Maalt Specialized Bulk, LLC	49%	Equity	13	13
Clean Energy Fuels Corp. (common stock)	—	Fair Value	—	12
Clean Energy Fuels Corp. (convertible notes)	—	Cost	—	100
Gastar Exploration Ltd.	—	Fair Value	—	8
Other	—	—	12	11
Total investments			$615	$728

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

FTS International, Inc. FTS International, Inc. (FTS), based in Fort Worth, Texas, is a privately held company which, through its subsidiaries, provides hydraulic fracturing and other services to oil and gas companies.
During the Current Period, we recorded negative equity method adjustments, prior to intercompany profit eliminations, of $17 million for our share of FTS's net loss and recorded an accretion adjustment of $34 million related to the excess of our underlying equity in net assets of FTS over our carrying value. The carrying value of our investment in FTS was less than our underlying equity in net assets by approximately $333 million as of September 30, 2013, of which $31 million was attributed to goodwill. During the Current Period, the value attributed to goodwill decreased by $265 million, which represents our proportionate share, net of tax, of an impairment recorded by FTS related to its goodwill. The value not attributed to goodwill is being accreted over the nine-year weighted average estimated useful life of the underlying assets. Additionally, in the Current Period, we purchased FTS common stock offered to existing stockholders for $3 million.
Chaparral Energy, Inc. Chaparral Energy, Inc. (Chaparral), based in Oklahoma City, Oklahoma, is a private independent oil and natural gas company engaged in the production, acquisition and exploitation of oil and natural gas properties.
In the Current Period, we recorded positive equity method adjustments of $11 million related to our share of Chaparral's net income, a $4 million charge related to our share of its other comprehensive income, and an amortization adjustment of $3 million related to our carrying value in excess of our underlying equity in net assets. The carrying value of our investment in Chaparral was in excess of our underlying equity in net assets by approximately $49 million as of September 30, 2013. 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.
Sundrop Fuels, Inc. Sundrop Fuels, Inc. (Sundrop), is a privately held cellulosic biofuels company based in Longmont, Colorado that is constructing a nonfood biomass-based "green gasoline" plant.
In the Current Period, we recorded a $14 million charge related to our share of Sundrop's net loss. The carrying value of our investment in Sundrop was in excess of our underlying equity in net assets by approximately $53 million as of September 30, 2013. This excess will be amortized over the life of the plant, once it is placed into service.
Twin Eagle Resource Management LLC. Twin Eagle Resource Management LLC (Twin Eagle) is a natural gas trading and management firm. During the Current Period, we recorded a $4 million charge related to our share of Twin Eagle's net loss.
Maalt Specialized Bulk, LLC. Maalt Specialized Bulk, LLC (Maalt) is engaged in bulk transportation services of sand. During the Current Period, we recorded a nominal positive equity method adjustment related to our share of Maalt's net income.
Clean Energy Fuels Corp. Clean Energy Fuels Corp. (Nasdaq:CLNE) (Clean Energy), based in Seal Beach, California, builds and operates compressed natural gas (CNG) and liquefied natural gas (LNG) fueling stations; manufactures CNG and LNG equipment and technologies; converts vehicles to natural gas; and develops renewable natural gas production facilities.
In the Current Quarter, we sold all of our shares of Clean Energy common stock for cash proceeds of approximately $13 million. We recorded a $3 million gain related to the sale.
In the Current Period, we sold our $100 million investment in Clean Energy convertible notes for cash proceeds of $85 million. The buyer also assumed our commitment to purchase the third and final $50 million tranche of Clean Energy convertible notes. We recorded a $15 million loss related to this sale.
Gastar Exploration Ltd. Gastar Exploration Ltd. (NYSE MKT:GST) (Gastar), based in Houston, Texas, is an independent energy company engaged in the exploration, development and production of natural gas and oil in the U.S. In the Current Period, we sold our investment in Gastar for cash proceeds of $10 million.
Other. In the Current Period, we sold an equity investment for cash proceeds of $6 million and recorded a $5 million gain associated with the transaction.

41

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

10. Variable Interest Entities

We consolidate the activities of VIEs of which we are the primary beneficiary. The primary beneficiary of a VIE is that variable interest holder possessing a controlling financial interest through (i) its power to direct the activities of the VIE that most significantly impact the VIE’s economic performance and (ii) its obligation to absorb losses or its right to receive benefits from the VIE that could potentially be significant to the VIE. In order to determine whether we own a variable interest in a VIE, we perform qualitative analysis of the entity’s design, organizational structure, primary decision makers and relevant agreements.

Consolidated VIE

Chesapeake Granite Wash Trust. For a discussion of the formation, operations and presentation of the Trust, please see Noncontrolling Interests in Note 6. The Trust is considered a VIE due to the lack of voting or similar decision-making rights by its equity holders regarding activities that have a significant effect on the economic success of the Trust. Our ownership in the Trust and our obligations under the development agreement and related drilling support lien constitute variable interests. We have determined that we are the primary beneficiary of the Trust because (i) we have the power to direct the activities that most significantly impact the economic performance of the Trust via our obligations to perform under the development agreement, and (ii) as a result of the subordination and incentive thresholds applicable to the subordinated units we hold in the Trust, we have the obligation to absorb losses and the right to receive residual returns that could potentially be significant to the Trust. As a result, we consolidate the Trust in our financial statements, and the common units of the Trust owned by third parties are reflected as a noncontrolling interest.

The Trust is a consolidated entity whose legal existence is separate from Chesapeake and our other consolidated subsidiaries, and the Trust is not a guarantor of any of Chesapeake’s debt. The creditors or beneficial holders of the Trust have no recourse to the general credit of Chesapeake; however, we have certain obligations to the Trust through the development agreement that are secured by a drilling support lien on our retained interest in the development wells up to a specified maximum amount recoverable by the Trust, which could result in the Trust acquiring all or a portion of our retained interest in the undeveloped portion of an area of mutual interest, if we do not meet our drilling commitment. In consolidation, as of September 30, 2013, approximately $337 million of net natural gas and oil properties, $24 million of current liabilities, $1 million of cash and cash equivalents, $7 million of short-term derivative liabilities and $1 million of long-term derivative liabilities were attributable to the Trust. We have presented parenthetically on the face of the condensed consolidated balance sheets the assets of the Trust that can be used only to settle obligations of the Trust and the liabilities of the Trust for which creditors do not have recourse to the general credit of Chesapeake.

Unconsolidated VIE

Mineral Acquisition Company I, L.P. In 2012, MAC-LP, L.L.C., a wholly owned non-guarantor unrestricted subsidiary of Chesapeake, entered into a partnership agreement with KKR Royalty Aggregator LLC (KKR) to form Mineral Acquisition Company I, L.P. The purpose of the partnership is to acquire mineral interests, or royalty interests carved out of mineral interests, in oil and natural gas basins in the continental United States. We are committed to acquire for our own account (outside the partnership) 10% of any acquisition agreed upon by the partnership up to a maximum of $25 million, and the partnership will acquire the remaining 90% up to a maximum of $225 million, funded entirely by KKR, making KKR the sole equity investor. We have significant influence over the decisions made by the partnership, as we hold two of five seats on the board of directors. We will receive proportionate distributions from the partnership of any cash received from royalties in excess of expenses paid, ranging from 7% to 22.5%. The partnership is considered a VIE because KKR’s control over the partnership is disproportionate to its economic interest. This VIE remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. We are using the equity method to account for this investment.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

11. Net (Gains) Losses on Sales of Fixed Assets

For assets outside of our full cost pool, the cost of assets retired or otherwise disposed of and the applicable accumulated depreciation are removed from accounts, and the resulting gain or loss is reflected as a component of operating expenses. A summary of our gains or losses by asset class for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	($ in millions)			
Gathering systems and treating plants	$(132)	$(7)	$(311)	$(8)
Drilling rigs and equipment	—	10	1	12
Buildings and land	1	—	24	—
Other	(1)	4	(4)	1
Total net (gains) losses on sales of fixed assets	$(132)	$7	$(290)	$5

Gathering Systems and Treating Plants

In the Current Quarter, our wholly owned midstream subsidiary, CMD, sold its wholly owned midstream subsidiary, Mid-America Midstream Gas Services, L.L.C. (MAMGS), to SemGas, L.P. (SemGas), a wholly owned subsidiary of SemGroup Corporation, for net proceeds of approximately $306 million, subject to post-closing adjustments. We recorded a $141 million pre-tax gain associated with this transaction. MAMGS owns certain gathering and processing assets located in the Mississippi Lime play, and the transaction with SemGas included a new long-term fixed-fee gathering and processing agreement covering acreage dedication areas in the Mississippi Lime play.

In the Current Period, CMD sold its wholly owned subsidiary, Granite Wash Midstream Gas Services, L.L.C. (GWMGS), to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE:MWE), for net proceeds of approximately $252 million, subject to post-closing adjustments. We recorded a $105 million pre-tax gain associated with this transaction. GWMGS owns certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE included new long-term fixed-fee agreements for gas gathering, compression, treating and processing services.

In the Current Period, we sold our interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP (NYSE:WES) for proceeds of approximately $134 million. We recorded a $55 million pre-tax gain associated with this transaction.

Buildings and Land

In the Current Period, the net losses on sales of buildings and land were primarily from the sale of certain of our buildings and land in our Barnett Shale operating area.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

12. Impairments

Impairment of Natural Gas and Oil Properties

On a quarterly basis, we analyze our unevaluated leasehold and transfer to evaluated properties leasehold that can be associated with reserves, leasehold that expired in the quarter, or leasehold that is not a part of our development strategy and will be abandoned. We also review, on a quarterly basis, the carrying value of our natural gas and oil properties under the full cost accounting rules of the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues from proved reserves (adjusted for cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. In the Prior Quarter, capitalized costs of natural gas and oil properties exceeded the ceiling, resulting in an impairment in the carrying value of natural gas and oil properties of $3.315 billion. For the ceiling test calculation, costs used are those as of the end of the appropriate quarterly period, and estimated future net revenues are calculated using the unweighted arithmetic average of natural gas and oil prices on the first day of each month within the 12-month period prior to the ending date of the quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives designated as cash flow hedges. Cash flow hedges as of September 30, 2012, which related to future periods, increased the ceiling test impairment by $279 million.

Impairments of Fixed Assets and Other

We test our long-lived assets, other than natural gas and oil properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable and recognize an impairment loss if the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. A summary of our impairments of fixed assets by asset class and other charges for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	($ in millions)			
Buildings and land	$8	$7	$247	$227
Drilling rigs and equipment	24	31	27	54
Gathering systems	21	—	22	—
Other	32	—	47	—
Total impairments of fixed assets and other	$85	$38	$343	$281

Buildings and Land. In June 2013, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. These assets are being actively marketed and we believe it is probable that these assets will be sold over the next 12 months. As a result, these assets qualified as held for sale as of September 30, 2013. We recognized an impairment loss of $138 million during the Current Period on these assets for the difference between the carrying amount and fair value of the assets, less the anticipated costs to sell.

Given the impairment losses associated with these assets, we tested other noncore buildings and land that we own in the Oklahoma City area for recoverability in the Current Period. Our estimate of the future undiscounted cash flows for these assets was less than their carrying amounts, and we recognized an additional impairment loss of $44 million on these assets for the difference between the carrying amount and fair value of the assets. We measured the fair value of these assets based on prices from orderly sales transactions for comparable properties between market participants and, in certain cases, discounted cash flows. The buildings and land are included in our other segment. In addition, in the Current Period, we recognized an impairment loss of $28 million related to three office buildings in the Oklahoma City area. We received a purchase offer from a third party that we used to determine the fair value of the office buildings. As of September 30, 2013, the office buildings were classified as held for sale and included in our other segment. We anticipate selling the buildings in the 2013 fourth quarter.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Due to a decrease in the estimated market prices of certain surface land classified as held for sale in the Fort Worth area, in the Current Period we recognized an additional impairment loss of $31 million. See below for discussion of the impairment of Barnett surface land in the Prior Period. We measured the fair value of these assets based on recent prices from orderly sales transactions for comparable properties between market participants. The surface land is included in our other segment.

In the Prior Period, we recognized $227 million of impairment losses associated with an office building and surface land located in our Barnett Shale operating area. Due to depressed natural gas prices, we initiated a significant reduction in our Barnett Shale operations. The change in business climate in the Barnett Shale required us to test these long-lived assets for recoverability in the Prior Period. We received a purchase offer from a third party that we used to determine the fair value of the office building and measured the fair value of the surface land using prices from orderly sales transactions for comparable properties between market participants. The office building and surface land are included in our other segment.

Drilling Rigs and Equipment. In the Current Quarter, we recognized $24 million of impairment losses on eight owned drilling rigs (seven of which are classified as held for sale assets as of September 30, 2013). In the Prior Quarter, we negotiated the purchase of 22 rigs previously sold in our sale leaseback transactions described in Note 4 from various lessors for an aggregate purchase price of $53 million, of which $25 million was deemed to be early lease termination costs and was recognized as impairments of fixed assets and other in the condensed consolidated statement of operations. In addition, in the Prior Quarter and the Prior Period, we recognized $6 million and $20 million, respectively, of impairment losses on certain of our owned drilling rigs due to the expectation that these drilling rigs would have insufficient cash flow to recover carrying values because of a change in business climate resulting from depressed natural gas prices. We estimated the fair value of the drilling rigs using prices expected to be received to sell each rig in an orderly transaction between market participants. Also in the Prior Period, we recognized $9 million of impairment losses primarily related to drill pipe and other oilfield services equipment. The drilling rigs and equipment are included in our oilfield services operating segment.

Gathering Systems. In the Current Quarter, we recognized approximately $18 million of impairment losses on certain of our gathering systems classified as held for sale as of September 30, 2013 and December 31, 2012 based on decreases in the estimated fair value of these assets. We estimated the fair value of the gathering systems using prices expected to be received to sell each gathering system in an orderly transaction between market participants. These gathering systems are included in our marketing, gathering and compression operating segment.

Other. In the Current Quarter, we terminated a gas gathering agreement and recorded a charge of $26 million within impairments of fixed assets and other in the condensed consolidated statement of operations.

13. Restructuring and Other Termination Benefits

On September 9, 2013, we committed to a workforce reduction plan as part of a company-wide reorganization effort intended to reduce costs. The reduction was communicated to affected employees on various dates within the months of September and October, and all such notifications were completed by October 11, 2013. The plan resulted in a reduction of approximately 900 employees. In connection with the reduction, we expect to incur a total cost of $70 million, of which approximately $31 million was recorded in the Current Quarter for employees terminated in September, and we expect to recognize the remaining $39 million in the 2013 fourth quarter for employees terminated in October. Of the $31 million in charges incurred in the Current Quarter, approximately $1 million was paid in the Current Quarter.

During the Current Quarter and the Current Period, we also incurred charges of approximately $28 million and $42 million, respectively, related to other workforce reductions, including executive officer separations.

On April 1, 2013, Aubrey K. McClendon, the co-founder of the Company, ceased serving as President and Chief Executive Officer (CEO) and as a director of the Company pursuant to his agreement with the Board of Directors announced on January 29, 2013. Mr. McClendon’s departure from the Company was treated as a termination without cause under his employment agreement. On April 18, 2013, the Company and Mr. McClendon entered into a Founder

Separation and Services Agreement, effective January 29, 2013, regarding his separation from employment and to facilitate the relationship between the Company and Mr. McClendon as joint working interest owners of oil and gas wells, leases and acreage. In the Current Quarter and Current Period, we incurred charges of approximately $3 million and $67 million, respectively, related to Mr. McClendon’s departure.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

In December 2012, Chesapeake announced that it had offered a voluntary separation program (VSP) to certain employees as part of the Company's ongoing efforts to improve efficiencies and reduce costs. The VSP was offered to approximately 275 employees who met criteria based upon a combination of age and years of Chesapeake service. Employees had until February 7, 2013 to respond, and 211 employees accepted the offer. Certain employees have a separation date in the 2013 fourth quarter. We are recognizing the expense related to their termination benefits over their remaining service period, including $1 million recognized in the Current Quarter.
Substantially all of the restructuring and other termination benefits in the Current Period are in the exploration and production operating segment. A summary of our restructuring and other termination benefits for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period is as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	($ in millions)			
Restructuring charges under workforce reduction plan:				
Salary expense	$5	$—	$5	$—
Acceleration of stock-based compensation	25	—	25	—
Other termination benefits	1	—	1	—
Total restructuring charges under workforce reduction plan	31	—	31	—
Termination benefits provided to Mr. McClendon:				
Salary and bonus expense	—	—	11	—
Acceleration of 2008 performance bonus “claw-back” feature	—	—	11	—
Acceleration of stock-based compensation	—	—	22	—
Acceleration of performance share unit awards	3	—	16	—
Estimated aircraft usage benefits	—	—	7	—
Total termination benefits provided to Mr. McClendon	3	—	67	—
Termination benefits provided to VSP participants:				
Salary and bonus expense	—	—	33	—
Acceleration of stock-based compensation	1	—	28	—
Other termination benefits	—	—	2	—
Total termination benefits provided to VSP participants	1	—	63	—
Other termination benefits	28	3	42	4
Total restructuring and other termination benefits	$63	$3	$203	$4

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

14. 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.

Recurring Fair Value Measurement

Other Current Assets. Assets related to forfeited Company matches of employee contributions to Chesapeake's 401(k) plan and deferred compensation plan are included in other current assets. The fair value of these assets is determined using quoted market prices as they consist of exchange traded securities.

Investments. The fair value of Chesapeake's investments in Clean Energy and Gastar common stock was based on quoted market prices.

Other Current Liabilities. Liabilities related to Chesapeake's deferred compensation plan are included in other current liabilities. The fair values of these liabilities are determined using quoted market prices, as the plan consists of exchange-traded mutual funds.

Derivatives. The fair value of most of our derivatives is based on third-party pricing models which utilize 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 natural gas, oil, interest rate and cross currency swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. All other derivatives have some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivatives are also subject to the risk that either party to a contract will be unable to meet its obligations. We factor non-performance risk into 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.

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, 2013:

	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):				
Other current assets	$93	$—	$—	$93
Other current liabilities	(89)	—	—	(89)
Derivatives:				
Commodity assets	—	105	21	126
Commodity liabilities	—	(103)	(606)	(709)
Interest rate liabilities	—	(88)	—	(88)
Foreign currency liabilities	—	(5)	—	(5)
Total derivatives	—	(91)	(585)	(676)
Total	$4	$(91)	$(585)	$(672)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2012:

	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):				
Other current assets	$4	$—	$—	$4
Investments	20	—	—	20
Other long-term assets	88	—	—	88
Other long-term liabilities	(87)	—	—	(87)
Derivatives:				
Commodity assets	—	105	10	115
Commodity liabilities	—	(13)	(1,026)	(1,039)
Interest rate liabilities	—	(35)	—	(35)
Foreign currency liabilities	—	(20)	—	(20)
Total derivatives	—	37	(1,016)	(979)
Total	$25	$37	$(1,016)	$(954)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

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

	Derivatives Commodity	Interest Rate
	($ in millions)	
Beginning Balance as of January 1, 2013	$(1,016)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	338	(1)
Total purchases, issuances, sales and settlements:		
Sales	—	1
Settlements	93	—
Ending Balance as of September 30, 2013	$(585)	$—
Beginning Balance as of January 1, 2012	$(1,654)	$—
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	525	4
Total purchases, issuances, sales and settlements:		
Sales	—	(6)
Settlements	56	—
Ending Balance as of September 30, 2012	$(1,073)	$(2)

(a)	Natural Gas, Oil and NGL Sales		Interest Expense	
	2013	2012	2013	2012
	($ in millions)			
Total gains (losses) included in earnings for the period	$338	$525	$(1)	$4
Change in unrealized gains (losses) relating to assets still held at reporting date	$327	$370	$—	$(2)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

Qualitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements
The significant unobservable inputs for Level 3 derivative contracts include unpublished forward prices of natural gas and oil, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of our derivative contracts. For example, an increase (decrease) in the forward prices and volatility of natural gas and oil prices will decrease (increase) the fair value of natural gas and oil derivatives and adverse changes to our counterparties' creditworthiness will decrease the fair value of our derivatives.
Quantitative Disclosures about Unobservable Inputs for Level 3 Fair Value Measurements

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value September 30, 2013
				($ in millions)
Oil Trades[a]	Oil price volatility curves	9.94% - 25.79%	16.44 %	$(369)
Oil Basis Swaps[b]	Physical pricing point forward curves	$3.03 - $4.65	$4.33	$1
Natural Gas Trades[a]	Natural gas price volatility curves	20.08% - 34.86%	22.10 %	$(215)
Natural Gas Basis Swaps[b]	Physical pricing point forward curves	($1.64) - $0	$(0.36)	$(2)

(a) Fair value is based on an estimate derived from option models.
(b) Fair value is based on an estimate of discounted cash flows.

Nonrecurring Fair Value Measurements
In the Current Period, we determined we would sell certain of our buildings and land (other than our core campus) in the Oklahoma City area. Fair value measurements were applied with respect to these non-financial assets, measured on a nonrecurring basis, to determine impairments. We used the income approach, specifically discounted cash flows, for income-producing assets and the market approach for the remaining assets. As the fair values estimated using the market approach were based on recent prices from orderly sales transactions for comparable properties between market participants, the values of these properties are classified as Level 2. The discounted cash flow method includes the development of both current operating metrics as well as assumptions pertaining to the subsequent change of such metrics, including rent growth, operating expense growth and absorption. These assumptions are applied to a specified period to develop future cash flow projections that are then discounted to estimate fair value. Due to these assumptions, the values of these properties are classified as Level 3. See Note 12 for further discussion of the impairments recorded.

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. The carrying values of financial instruments comprising cash and cash equivalents, restricted cash, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our exchange-traded debt using quoted market prices (Level 1). The fair value of all other debt, which consists of our credit facilities and our term loan, is estimated using our credit default swap rate (Level 2). Fair value is compared to the carrying value, excluding the impact of interest rate derivatives, in the table below.

	September 30, 2013		December 31, 2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value

		($ in millions)		
Current maturities of long-term debt (Level 1)	$—	$—	$463	$480
Long-term debt (Level 1)	$10,470	$11,333	$9,759	$10,457
Long-term debt (Level 2)	$2,252	$2,241	$2,378	$2,284

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

15. Segment Information

In accordance with accounting guidance for disclosures about segments of an enterprise and related information, we have three reportable operating segments. Our exploration and production operating segment, natural gas, oil and NGL marketing, gathering and compression operating segment and oilfield services operating segment are managed separately because of the nature of their products and services. The exploration and production operating segment is responsible for finding and producing natural gas, oil and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of natural gas, oil and NGL primarily from Chesapeake-operated wells. The oilfield services operating segment is responsible for contract drilling, oilfield trucking, oilfield rentals, hydraulic fracturing and other oilfield services operations for both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of natural gas, oil and NGL related to Chesapeake's ownership interests by the marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. Such amounts totaled \$2.002 billion, \$1.541 billion, \$5.682 billion and \$3.877 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. Revenues generated by the oilfield services operating segment for work performed for Chesapeake's exploration and production operating segment are reclassified to the full cost pool based on Chesapeake's ownership interest. Revenues reclassified totaled \$306 million, \$330 million, \$1.041 billion and \$988 million for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively. The following table presents selected financial information for Chesapeake's operating segments:

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

	Exploration and Production	Marketing, Gathering and Compression	Oilfield Services	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)					
Three Months Ended September 30, 2013:						
Revenues	$1,586	$5,034	$551	$4	$(2,308)	$4,867
Intersegment revenues	—	(2,002)	(306)	—	2,308	—
Total revenues	$1,586	$3,032	$245	$4	$—	$4,867
Income (Loss) Before Income Taxes	$430	$128	$(37)	$(48)	$(86)	$387
Three Months Ended September 30, 2012:						
Revenues	$1,437	$2,922	$482	$—	$(1,871)	$2,970
Intersegment revenues	—	(1,541)	(330)	—	1,871	—
Total revenues	$1,437	$1,381	$152	$—	$—	$2,970
Income (Loss) Before Income Taxes	$(3,073)	$120	$(2)	$(152)	$(124)	$(3,231)
Nine Months Ended September 30, 2013:						
Revenues	$5,444	$12,553	$1,677	$27	$(6,736)	$12,965
Intersegment revenues	—	(5,682)	(1,041)	(13)	6,736	—
Total revenues	$5,444	$6,871	$636	$14	$—	$12,965
Income (Loss) Before Income Taxes	$654	$395	$(12)	$808	$(284)	$1,561
Nine Months Ended September 30, 2012:						
Revenues	$4,622	$7,587	$1,434	$—	$(4,865)	$8,778
Intersegment revenues	—	(3,877)	(988)	—	4,865	—
Total revenues	$4,622	$3,710	$446	$—	$—	$8,778
Income (Loss) Before Income Taxes	$(1,896)	$1,279	$96	$(654)	$(362)	$(1,537)
As of September 30, 2013:						
Total Assets	$35,919	$2,323	$1,981	$5,014	$(2,949)	$42,288
As of						

December 31, 2012:						
Total Assets	$37,004	$2,291	$2,115	$2,529	$(2,328)	$41,611

52

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

16. Condensed Consolidating Financial Information

Chesapeake Energy Corporation is a holding company, owns no operating assets, and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes and contingent convertible senior notes listed in Note 3 are fully and unconditionally guaranteed, jointly and severally, by certain of our wholly owned subsidiaries on a senior unsecured basis. Our oilfield services subsidiary, COS, and its subsidiaries are separately capitalized and are not guarantors of our senior notes or our other debt obligations, but are subject to the covenants and guarantees in the oilfield services revolving bank credit facility agreement referred to in Note 3 that limit their ability to pay dividends or distributions or make loans to Chesapeake. Our midstream subsidiary, CMD, and certain of its subsidiaries, including Chesapeake Midstream Operating, L.L.C. (CMO), were added as guarantors of our senior notes and certain other obligations in June 2012 upon the termination of the midstream credit facility. In December 2012 upon the sale of CMO to ACMP, CMO and its subsidiaries were then released as guarantors of our senior notes and of our other debt obligations, and all prior year information was restated at that time to reflect CMO and its subsidiaries as non-guarantor subsidiaries and CMD and certain of its remaining subsidiaries as guarantor subsidiaries. Certain of our oilfield services subsidiaries, subsidiaries with noncontrolling interests, consolidated variable interest entities and certain de minimis subsidiaries are non-guarantors.

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, 2013 and December 31, 2012 and for the three and nine months ended September 30, 2013 and 2012. Such financial information may not necessarily be indicative of our results of operations, cash flows or financial position had these subsidiaries operated as independent entities.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF SEPTEMBER 30, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$966	$—	$ 14	$7	$987
Restricted cash	—	—	82	(7)	75
Other	104	2,606	645	(423)	2,932
Current assets held for sale	—	—	—	—	—
Intercompany receivable, net	25,863	—	—	(25,863)	—
Total Current Assets	26,933	2,606	741	(26,286)	3,994
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,245	3,123	151	32,519
Other property and equipment, net	—	2,561	1,445	(1)	4,005
Property and equipment held for sale, net	—	571	26	—	597
Total Property and Equipment, Net	—	32,377	4,594	150	37,121
LONG-TERM ASSETS:					
Other assets	114	1,316	115	(372)	1,173
Investments in subsidiaries and intercompany advances	2,211	(238)	—	(1,973)	—
TOTAL ASSETS	$29,258	$36,061	$ 5,450	$(28,481)	$42,288
CURRENT LIABILITIES:					
Current liabilities	$242	$5,427	$ 431	$(422)	$5,678
Intercompany payable, net	—	24,740	1,279	(26,019)	—
Total Current Liabilities	242	30,167	1,710	(26,441)	5,678
LONG-TERM LIABILITIES:					
Long-term debt, net	11,801	—	935	—	12,736
Deferred income tax liabilities	638	2,397	60	328	3,423
Other long-term liabilities	381	1,286	900	(464)	2,103
Total Long-Term Liabilities	12,820	3,683	1,895	(136)	18,262
EQUITY:					
Chesapeake stockholders' equity	16,196	2,211	1,845	(4,056)	16,196
Noncontrolling interests	—	—	—	2,152	2,152
Total Equity	16,196	2,211	1,845	(1,904)	18,348
TOTAL LIABILITIES AND EQUITY	$29,258	$36,061	$ 5,450	$(28,481)	$42,288

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET
AS OF DECEMBER 31, 2012
($ in millions)

	Parent[(a)]	Guarantor Subsidiaries[(a)]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CURRENT ASSETS:					
Cash and cash equivalents	$228	$—	$ 59	$—	$287
Restricted cash	—	—	111	—	111
Other	1	2,378	512	(345)	2,546
Current assets held for sale	—	—	4	—	4
Intercompany receivable, net	25,356	—	—	(25,356)	—
Total Current Assets	25,585	2,378	686	(25,701)	2,948
PROPERTY AND EQUIPMENT:					
Natural gas and oil properties, at cost based on full cost accounting, net	—	29,083	3,057	(222)	31,918
Other property and equipment, net	—	3,066	1,549	—	4,615
Property and equipment held for sale, net	—	255	379	—	634
Total Property and Equipment, Net	—	32,404	4,985	(222)	37,167
LONG-TERM ASSETS:					
Other assets	217	1,396	261	(378)	1,496
Investments in subsidiaries and intercompany advances	2,241	(186)	—	(2,055)	—
TOTAL ASSETS	$28,043	$35,992	$ 5,932	$(28,356)	$41,611
CURRENT LIABILITIES:					
Current liabilities	$789	$5,377	$ 424	$(345)	$6,245
Current liabilities held for sale	—	—	21	—	21
Intercompany payable, net	—	24,166	1,312	(25,478)	—
Total Current Liabilities	789	29,543	1,757	(25,823)	6,266
LONG-TERM LIABILITIES:					
Long-term debt, net	11,089	—	1,068	—	12,157
Deferred income tax liabilities	361	2,425	127	(106)	2,807
Other liabilities	235	1,783	839	(372)	2,485
Total Long-Term Liabilities	11,685	4,208	2,034	(478)	17,449
EQUITY:					
Chesapeake stockholders' equity	15,569	2,241	2,141	(4,382)	15,569
Noncontrolling interests	—	—	—	2,327	2,327
Total Equity	15,569	2,241	2,141	(2,055)	17,896
TOTAL LIABILITIES AND EQUITY	$28,043	$35,992	$ 5,932	$(28,356)	$41,611

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent of $228 million, which was incorrectly presented in the Guarantor subsidiaries as of December 31, 2012. The impact of this error was not material to any previously issued financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED SEPTEMBER 30, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$1,400	$185	$1	$1,586
Marketing, gathering and compression	—	3,031	1	—	3,032
Oilfield services	—	—	552	(303)	249
Total Revenues	—	4,431	738	(302)	4,867
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	268	14	—	282
Production taxes	—	60	2	—	62
Marketing, gathering and compression	—	3,009	—	—	3,009
Oilfield services	—	23	460	(272)	211
General and administrative	—	97	24	(1)	120
Restructuring and other termination benefits	—	63	—	—	63
Natural gas, oil and NGL depreciation, depletion and amortization	—	591	61	—	652
Depreciation and amortization of other assets	—	43	74	(38)	79
Impairment of natural gas and oil properties	—	—	99	(99)	—
Impairments of fixed assets and other	—	56	29	—	85
Net (gains) losses on sales of fixed assets	—	(133)	—	1	(132)
Total Operating Expenses	—	4,077	763	(409)	4,431
INCOME (LOSS) FROM OPERATIONS	—	354	(25)	107	436
OTHER INCOME (EXPENSE):					
Interest expense	(207)	(27)	(21)	215	(40)
Losses on investments	—	(22)	—	—	(22)
Impairment of investment	—	—	(1)	1	—
Gains (losses) on sales of investments	—	3	—	—	3
Other income (expense)	208	44	2	(244)	10
Equity in net earnings of subsidiary	201	(75)	—	(126)	—
Total Other Income (Expense)	202	(77)	(20)	(154)	(49)
INCOME (LOSS) BEFORE INCOME TAXES	202	277	(45)	(47)	387
INCOME TAX EXPENSE (BENEFIT)	—	134	(17)	30	147
NET INCOME (LOSS)	202	143	(28)	(77)	240
Net income attributable to noncontrolling interests	—	—	—	(38)	(38)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	202	143	(28)	(115)	202

Other comprehensive income (loss)	2	1	(2)	—	1
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$204	$144	$(30)	$(115)	$203

56

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
THREE MONTHS ENDED SEPTEMBER 30, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$1,357	$79	$1	$1,437
Marketing, gathering and compression	—	1,319	62	—	1,381
Oilfield services	—	—	485	(333)	152
Total Revenues	—	2,676	626	(332)	2,970
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	311	9	—	320
Production taxes	—	51	2	—	53
Marketing, gathering and compression	—	1,310	29	—	1,339
Oilfield services	—	80	361	(325)	116
General and administrative	—	108	37	—	145
Restructuring and other termination benefits	—	2	1	—	3
Natural gas, oil and NGL depreciation, depletion and amortization	—	716	46	—	762
Depreciation and amortization of other assets	—	43	58	(35)	66
Impairment of natural gas and oil properties	—	3,167	148	—	3,315
Impairments of fixed assets and other	—	8	30	—	38
Net (gains) losses on sales of fixed assets	—	4	3	—	7
Total Operating Expenses	—	5,800	724	(360)	6,164
INCOME (LOSS) FROM OPERATIONS	—	(3,124)	(98)	28	(3,194)
OTHER INCOME (EXPENSE):					
Interest expense	(289)	(18)	(21)	292	(36)
Losses on investments	—	(23)	—	—	(23)
Gains (losses) on sales of investments	—	—	31	—	31
Other income (expense)	286	79	3	(377)	(9)
Equity in net earnings (losses) of subsidiary	(2,010)	(127)	—	2,137	—
Total Other Income (Expense)	(2,013)	(89)	13	2,052	(37)
INCOME (LOSS) BEFORE INCOME TAXES	(2,013)	(3,213)	(85)	2,080	(3,231)
INCOME TAX EXPENSE (BENEFIT)	(1)	(1,204)	(33)	(22)	(1,260)
NET INCOME (LOSS)	(2,012)	(2,009)	(52)	2,102	(1,971)
Net income attributable to noncontrolling interests	—	—	—	(41)	(41)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(2,012)	(2,009)	(52)	2,061	(2,012)
Other comprehensive income (loss)	3	(7)	(2)	—	(6)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(2,009)	$(2,016)	$(54)	$2,061	$(2,018)

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$4,962	$473	$9	$5,444
Marketing, gathering and compression	—	6,861	10	—	6,871
Oilfield services	—	—	1,703	(1,053)	650
Total Revenues	—	11,823	2,186	(1,044)	12,965
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	838	39	—	877
Production taxes	—	167	6	—	173
Marketing, gathering and compression	—	6,776	5	—	6,781
Oilfield services	—	70	1,362	(889)	543
General and administrative	—	264	73	(1)	336
Restructuring and other termination benefits	—	200	3	—	203
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,771	174	—	1,945
Depreciation and amortization of other assets	—	137	218	(121)	234
Impairment of natural gas and oil properties	—	—	260	(260)	—
Impairments of fixed assets and other	—	307	36	—	343
Net gains (losses) on sales of fixed assets	—	(291)	—	1	(290)
Total Operating Expenses	—	10,239	2,176	(1,270)	11,145
INCOME (LOSS) FROM OPERATIONS	—	1,584	10	226	1,820
OTHER INCOME (EXPENSE):					
Interest expense	(703)	(70)	(63)	672	(164)
Losses on investments	—	(26)	—	—	(26)
Impairment of investment	—	(10)	(1)	1	(10)
Gains (losses) on sales of investments	—	(7)	—	—	(7)
Losses on purchases of debt	(70)	—	—	—	(70)
Other income (expense)	651	120	7	(760)	18
Equity in net earnings of subsidiary	916	(221)	—	(695)	—
Total Other Income (Expense)	794	(214)	(57)	(782)	(259)
INCOME (LOSS) BEFORE INCOME TAXES	794	1,370	(47)	(556)	1,561
INCOME TAX EXPENSE (BENEFIT)	(46)	605	(18)	53	594
NET INCOME (LOSS)	840	765	(29)	(609)	967
Net income attributable to noncontrolling interests	—	—	—	(127)	(127)
NET INCOME (LOSS) ATTRIBUTABLE	840	765	(29)	(736)	840

TO CHESAPEAKE					
Other comprehensive income	2	12	(1)	—	13
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$842	$777	$(30)	$(736)	$853

58

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS
NINE MONTHS ENDED SEPTEMBER 30, 2012
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
REVENUES:					
Natural gas, oil and NGL	$—	$4,410	$209	$3	$4,622
Marketing, gathering and compression	—	3,555	155	—	3,710
Oilfield services	—	—	1,440	(994)	446
Total Revenues	—	7,965	1,804	(991)	8,778
OPERATING EXPENSES:					
Natural gas, oil and NGL production	—	989	16	—	1,005
Production taxes	—	137	4	—	141
Marketing, gathering and compression	—	3,549	82	—	3,631
Oilfield services	—	141	1,029	(849)	321
General and administrative	—	343	93	—	436
Restructuring and other termination benefits	—	3	1	—	4
Natural gas, oil and NGL depreciation, depletion and amortization	—	1,761	95	—	1,856
Depreciation and amortization of other assets	—	132	205	(104)	233
Impairment of natural gas and oil properties	—	3,167	148	—	3,315
Impairment of fixed assets and other	—	227	54	—	281
Net (gains) losses on sales of fixed assets	—	2	3	—	5
Total Operating Expenses	—	10,451	1,730	(953)	11,228
INCOME (LOSS) FROM OPERATIONS	—	(2,486)	74	(38)	(2,450)
OTHER INCOME (EXPENSE):					
Interest expense	(682)	(3)	(64)	686	(63)
Earnings (losses) on investments	—	(142)	55	—	(87)
Gains on sales of investments	—	1,030	31	—	1,061
Other income (expense)	667	166	10	(841)	2
Equity in net earnings (losses) of subsidiary	(1,060)	(179)	—	1,239	—
Total Other Income (Expense)	(1,075)	872	32	1,084	913
INCOME (LOSS) BEFORE INCOME TAXES	(1,075)	(1,614)	106	1,046	(1,537)
INCOME TAX EXPENSE (BENEFIT)	(6)	(559)	41	(75)	(599)
NET INCOME (LOSS)	(1,069)	(1,055)	65	1,121	(938)
Net income attributable to noncontrolling interests	—	—	—	(131)	(131)
NET INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	(1,069)	(1,055)	65	990	(1,069)

Other comprehensive income (loss)	3	(25)	—	—	(22)
COMPREHENSIVE INCOME (LOSS) ATTRIBUTABLE TO CHESAPEAKE	$(1,066)	$(1,080)	$65	$990	$(1,091)

59

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
NINE MONTHS ENDED SEPTEMBER 30, 2013
($ in millions)

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$3,232	$362	$(33)	$3,561
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(4,642)	(639)	—	(5,281)
Proceeds from divestitures of proved and unproved properties	—	2,736	53	—	2,789
Additions to other property and equipment	—	(415)	(224)	—	(639)
Other investing activities	—	67	757	260	1,084
Net Cash Used In Investing Activities	—	(2,254)	(53)	260	(2,047)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	6,311	825	—	7,136
Payments on credit facilities borrowings	—	(6,310)	(958)	—	(7,268)
Proceeds from issuance of senior notes, net of discount and offering costs	2,274	—	—	—	2,274
Cash paid to purchase debt	(2,116)	—	—	—	(2,116)
Proceeds from sales of noncontrolling interests	—	5	—	—	5
Other financing activities	(374)	(297)	46	(220)	(845)
Intercompany advances, net	954	(687)	(267)	—	—
Net Cash Provided By (Used In) Financing Activities	738	(978)	(354)	(220)	(814)
Net increase (decrease) in cash and cash equivalents	738	—	(45)	7	700
Cash and cash equivalents, beginning of period	228	—	59	—	287
Cash and cash equivalents, end of period	$966	$—	$14	$7	$987

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS
NINE MONTHS ENDED SEPTEMBER 30, 2012
($ in millions)

	Parent[a]	Guarantor Subsidiaries[a]	Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES	$—	$2,779	$200	$(1,001)	$1,978
CASH FLOWS FROM INVESTING ACTIVITIES:					
Additions to proved and unproved properties	—	(10,208)	(130)	—	(10,338)
Proceeds from divestitures of proved and unproved properties	—	2,445	—	—	2,445
Additions to other property and equipment	—	(577)	(1,339)	—	(1,916)
Other investing activities	—	3,051	(158)	(1,238)	1,655
Net Cash Used In Investing Activities	—	(5,289)	(1,627)	(1,238)	(8,154)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from credit facilities borrowings	—	12,116	1,870	—	13,986
Payments on credit facilities borrowings	—	(12,051)	(1,563)	—	(13,614)
Proceeds from issuance of senior notes, net of discount and offering costs	1,263	—	—	—	1,263
Proceeds from issuance of term loans, net of discount and offering costs	3,789	—	—	—	3,789
Proceeds from sales of noncontrolling interests	—	—	1,056	—	1,056
Other financing activities	(367)	(154)	(2,217)	2,239	(499)
Intercompany advances, net	(4,618)	2,599	2,019	—	—
Net Cash Provided By Financing Activities	67	2,510	1,165	2,239	5,981
Change in cash and cash equivalents classified as current assets held for sale	(7)	—	(7)	—	(14)
Net increase in cash and cash equivalents	60	—	(269)	—	(209)
Cash and cash equivalents, beginning of period	1	—	350	—	351
Cash and cash equivalents, end of period	$61	$—	$81	$—	$142

(a) We have revised the amounts presented as cash and cash equivalents in the Guarantor Subsidiaries and Parent columns to properly reflect the cash of the Parent of $61 million, which was incorrectly presented as the Guarantor subsidiaries as of September 30, 2012. The impact of this error was not material to any previously issued financial statements.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS – (Continued)
(unaudited)

17. Recently Issued Accounting Standards

Recently Adopted Accounting Standards

In February 2012, the Financial Accounting Standards Board (FASB) issued guidance changing the presentation requirements of significant reclassifications out of accumulated other comprehensive income in their entirety and their corresponding effect on net income. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

In December 2011 and January 2013, the FASB issued guidance amending and expanding disclosure requirements about offsetting and related arrangements associated with derivatives. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

Recently Issued Accounting Standards

To reduce diversity in practice related to the presentation of unrecognized tax benefits, in July 2013 the FASB issued guidance requiring the presentation of an unrecognized tax benefit in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward. This net presentation is required unless a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date or the tax law of the jurisdiction does not require, and the entity does not intend to use, the deferred tax asset to settle any additional income tax that would result from the disallowance of the unrecognized tax benefit. The guidance will be effective on January 1, 2014; retrospective application and early adoption are permitted, but not required. Because we have historically presented unrecognized tax benefits net of net operating loss carryforwards, similar tax losses or tax credit carryforwards, this standard will not impact our consolidated financial statements.

In February 2013, the FASB issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We will adopt this standard effective January 1, 2014. We do not expect the adoption to have a material impact on our consolidated financial statements.

18. Subsequent Events

On November 1, 2013, we terminated a financing master lease agreement on 106 surface properties in the Fort Worth area for $257 million. We anticipate recording a loss of approximately $120 million in the 2013 fourth quarter associated with this extinguishment. See Note 5 for additional information on this financing obligation.

Subsequent to September 30, 2013, we acquired nine rigs subject to the master lease agreements described in Note 4. In conjunction with the purchases, we also terminated approximately $58 million of remaining lease commitments associated with these rigs. Total consideration paid was approximately $70 million and we anticipate recording a charge in the 2013 fourth quarter for the lease termination cost.

ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations
Financial Data
The following table sets forth certain information regarding our production volumes, natural gas, oil and natural gas liquids (NGL) sales, average sales prices received, other operating income and expenses for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net Production:				
Natural gas (bcf)	273.3	302.3	824.1	848.6
Oil (mmbbl)	11.0	9.0	30.9	22.3
NGL (mmbbl)	5.4	4.1	15.0	13.0
Natural gas equivalent (bcfe)[(a)]	371.9	381.1	1,099.4	1,060.5
Natural Gas, Oil and NGL Sales ($ in millions):				
Natural gas sales	$581	$543	$1,932	$1,359
Natural gas derivatives – realized gains (losses)[(b)]	37	52	(7)	391
Natural gas derivatives – unrealized gains (losses)	6	(90)	74	(401)
Total natural gas sales	624	505	1,999	1,349
Oil sales	1,115	792	2,975	2,038
Oil derivatives – realized gains (losses)[(b)]	(99)	25	(89)	6
Oil derivatives – unrealized gains (losses)	(197)	(14)	163	803
Total oil sales	819	803	3,049	2,847
NGL sales	143	129	396	401
NGL derivatives – realized gains (losses)[(b)]	—	—	—	(9)
NGL derivatives – unrealized gains (losses)	—	—	—	34
Total NGL sales	143	129	396	426
Total natural gas, oil and NGL sales	$1,586	$1,437	$5,444	$4,622
Average Sales Price (excluding gains (losses) on derivatives):				
Natural gas ($ per mcf)	$2.12	$1.80	$2.34	$1.60
Oil ($ per bbl)	$101.08	$88.07	$96.40	$91.31
NGL ($ per bbl)	$26.52	$31.22	$26.35	$30.86
Natural gas equivalent ($ per mcfe)	$4.94	$3.84	$4.82	$3.58
Average Sales Price (excluding unrealized gains (losses) on derivatives)[(b)]:				
Natural gas ($ per mcf)	$2.26	$1.97	$2.34	$2.06
Oil ($ per bbl)	$92.09	$90.79	$93.51	$91.55
NGL ($ per bbl)	$26.52	$31.22	$26.35	$30.17
Natural gas equivalent ($ per mcfe)	$4.78	$4.04	$4.74	$3.95

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Other Operating Income[(c)] ($ in millions):				
Marketing, gathering and compression net margin	$23	$42	$90	$79
Oilfield services net margin	$38	$36	$107	$125
Other Operating Income[(c)] ($ per mcfe):				
Marketing, gathering and compression net margin	$0.06	$0.11	$0.08	$0.07
Oilfield services net margin	$0.10	$0.09	$0.10	$0.12
Expenses ($ per mcfe):				
Natural gas, oil and NGL production	$0.76	$0.84	$0.80	$0.95
Production taxes	$0.17	$0.14	$0.16	$0.13
General and administrative expenses[(d)]	$0.32	$0.38	$0.31	$0.41
Natural gas, oil and NGL depreciation, depletion and amortization	$1.75	$2.00	$1.77	$1.75
Depreciation and amortization of other assets	$0.21	$0.17	$0.21	$0.22
Interest expense[(e)]	$0.11	$0.10	$0.10	$0.06
Interest Expense ($ in millions):				
Interest expense	$43	$38	$113	$67
Interest rate derivatives – realized (gains) losses	(3)	—	(6)	—
Interest rate derivatives – unrealized (gains) losses	—	(2)	57	(4)
Total interest expense	$40	$36	$164	$63

(a) Natural gas equivalent is based on six mcf of natural gas to one barrel of oil or one barrel of NGL. This ratio reflects an energy content equivalency and not a price or revenue equivalency. Given recent natural gas, oil and NGL prices, the price for an mcf of natural gas is significantly less than the price for an mcfe of oil or NGL.

(b) Includes settlements for commodity derivatives adjusted for option premiums. For derivatives closed early, settlements are reflected in the period of original contract expiration.

(c) Includes revenue and operating costs and excludes depreciation and amortization, impairments of fixed assets and other and net gains or losses on sales of fixed assets. See Depreciation and Amortization of Other Assets, Impairments of Fixed Assets and Other and Net (Gains) Losses on Sales of Fixed Assets under Results of Operations for details of the depreciation and amortization and impairments of assets and net gains or losses on sales of fixed assets associated with our marketing, gathering and compression and oilfield services operating segments.

(d) Includes stock-based compensation and excludes restructuring and other termination benefits.

(e) 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.

Overview

The Company is currently the second-largest producer of natural gas and the eleventh-largest producer of liquids in the U.S. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We also own substantial marketing, compression and oilfield services businesses.

Our Strategy

We have recently conducted a company-wide review of our operations, assets and organizational structure to determine how best to position the Company to maximize shareholder value going forward as we focus on the strategic priorities of financial discipline and profitable and efficient growth from captured resources.

We intend to infuse financial discipline through all aspects of our business, and we believe that the successful execution of this strategy will allow us to balance capital expenditures with cash flow from operations as well as reduce financial risk and complexity. We will also continue to utilize our hedging program to provide greater cash flow predictability. As a reflection of our focus on financial discipline, average production expenses during the Current Quarter and Current Period decreased 10% and 16% from the Prior Quarter and Prior Period, respectively. General and administrative expenses (excluding stock-based compensation and restructuring and other termination benefits) decreased 12% and 28% from the Prior Quarter and Prior Period, respectively, and we expect further decreases will be reflected in the future as a result of recent workforce reductions.

The Company holds a substantial inventory of resources that provides a foundation for future growth. We believe that focusing on profitable and efficient growth from captured resources will allow us to deliver attractive profit margins and financial returns in the future through all phases of the commodity price cycle. We are already seeing increased efficiencies through our leveraging of first-well investments made in prior periods, including drilling on pre-existing pads. We are also implementing a competitive capital allocation process designed to optimize our asset portfolio and identify the highest quality projects for future investment. To better understand our opportunities for continuous improvement, we will benchmark our performance against that of our peers and evaluate the performance of completed projects. We will also pay careful attention to safety, regulatory compliance and environmental stewardship measures while executing our growth strategy.

We have also transformed the organizational structure of the Company into Northern and Southern operating divisions and an Exploration and Subsurface Technology unit that are supported by enterprise-wide service departments. The Northern Division is responsible for managing our assets in the Utica Shale in Ohio, West Virginia and Pennsylvania, the Marcellus Shale in the northern Appalachian Basin in West Virginia and Pennsylvania, and the Niobrara Shale in the Powder River Basin in Wyoming. The Southern Division is responsible for managing our assets in the Eagle Ford Shale in South Texas, the Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime plays in the Anadarko Basin in northwestern Oklahoma, the Texas Panhandle and southern Kansas, the Haynesville/Bossier Shale in northwestern Louisiana and East Texas, and the Barnett Shale in the Fort Worth Basin of north-central Texas.

The new organizational structure is designed to increase accountability and communication throughout the organization, while encouraging standardization, efficiency and continuous improvement. As part of the reorganization, in the Current Quarter and through October 11, 2013, we reduced our workforce by approximately 1,000 employees, including approximately 900 under a workforce reduction plan we implemented in September and October 2013. We anticipate the workforce reduction will result in future cost savings and help position the Company for profitable and efficient growth. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report and Restructuring and Other Termination Benefits below on pages 82 and 87 for further discussion of our workforce reductions.

Operating Results

We own interests in approximately 46,500 producing natural gas and oil wells that are currently producing approximately 4.0 bcfe per day, net to our interest. Our Current Quarter production of 372 bcfe consisted of 273 bcf of natural gas (73% on a natural gas equivalent basis), 11.0 mmbbls of oil (18% on a natural gas equivalent basis) and 5.4 mmbbls of NGL (9% on a natural gas equivalent basis). Liquids represented 27% of total production during the Current Quarter, up from 21% in the Prior Quarter. Our daily production for the Current Quarter averaged approximately 4.042 bcfe, a decrease of 2% from the Prior Quarter and a nominal decrease from the 2013 second quarter. This decrease is primarily due to production losses associated with recent asset sales in the Mississippi Lime, northern Eagle Ford Shale and Haynesville Shale, as well as the sale of Permian assets in September and October of 2012. During the Current Quarter, average daily oil production increased 23% over the Prior Quarter and 4% over the 2013

65

second quarter, average daily NGL production increased 31% over the Prior Quarter and 12% over the 2013 second quarter, and average daily natural gas production decreased 10% over the Prior Quarter and 2% over the 2013 second quarter.

In the Current Quarter, we operated an average of 68 rigs, a decrease of nine rigs compared to the 2013 second quarter, and invested approximately $1.2 billion in drilling and completion costs, bringing Current Period drilling and completion costs to approximately $4.3 billion. Drilling and completion costs were lower in the Current Quarter than the 2013 second quarter as Chesapeake drilled and completed fewer wells in the Current Quarter than in the 2013 second quarter. Based on planned activity levels for the 2013 fourth quarter, we project that 2013 full-year drilling and completion costs will be $5.5 - $5.8 billion, a 36% decrease from 2012 drilling and completion costs of $8.8 billion.

Net expenditures for the acquisition of unproved properties were approximately $45 million during the Current Quarter and approximately $145 million for the Current Period. We are projecting to acquire $200 - $250 million of unproved properties for the 2013 full year, net of reimbursements from our joint venture partners. Other capital expenditures were approximately $170 million during the Current Quarter and approximately $700 million during the Current Period.

Divestitures

An essential part of our business strategy in 2013 is using the proceeds from divestitures to fund the spending gap between cash flow from operations and our capital expenditures and to reduce financial leverage and complexity and further enhance our liquidity. In 2013, through November 1, we sold natural gas and oil properties, midstream and other assets that we deemed were noncore or did not fit our long-term plans and we entered into a strategic joint venture for aggregate net proceeds of approximately $3.7 billion, approximately $1.2 billion of which we received in the Current Quarter and approximately $100 million of which we received in the 2013 fourth quarter. Also, see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of the drilling carries we continue to receive through our prior strategic joint ventures.

We will continue to divest noncore assets and noncore affiliates that we believe do not strengthen our long-term competitive position, but we expect that our 2014 capital budget will not be dependent on these sales. The Company anticipates completing additional asset sales for net proceeds of approximately $500 million during the 2013 fourth quarter and continues to pursue other asset sale transactions that may close in the first half of 2014.

Natural Gas and Oil Property Sales

On July 31, 2013, we sold assets in the northern Eagle Ford Shale to EXCO Operating Company, LP (EXCO) for net proceeds of approximately $617 million. In the Current Quarter, we received approximately $4 million of net proceeds for customary post-closing adjustments and may receive up to an additional $64 million of net proceeds pursuant to further customary post-closing adjustments. The assets sold included approximately 55,000 net acres in Zavala, Dimmit, La Salle and Frio counties, Texas.

On July 12, 2013, we sold assets in the Haynesville Shale to EXCO for net proceeds of approximately $257 million. We may receive up to an additional $32 million of net proceeds pursuant to customary post-closing adjustments. The assets sold included our operated and non-operated interests in approximately 9,600 net acres in DeSoto and Caddo parishes, Louisiana.

Natural Gas and Oil Property Joint Venture

On June 28, 2013, we completed a strategic joint venture with Sinopec International Petroleum Exploration and Production Corporation (Sinopec) in which Sinopec purchased a 50% undivided interest in approximately 850,000 acres in the Mississippi Lime play in northern Oklahoma (425,000 acres net to Sinopec). Total consideration for the transaction was approximately $1.020 in cash, of which approximately $949 million of net proceeds, or 93%, was received upon closing. We also received an additional $90 million at closing related to closing adjustments for activity between the effective date and closing date of the transaction. We may receive up to an additional $71 million of net proceeds pursuant to customary post-closing adjustments. All future exploration and development costs in the joint venture will be shared proportionately between the parties with no drilling carries involved.

Midstream Asset Sales

On August 1, 2013, our wholly owned subsidiary, Chesapeake Midstream Development, L.L.C. (CMD), sold its wholly owned midstream subsidiary, Mid-America Midstream Gas Services, L.L.C. (MAMGS), to SemGas, L.P. (SemGas), a wholly owned subsidiary of SemGroup Corporation, for net proceeds of approximately $306 million, subject to post-closing adjustments. We recorded a $141 pre-tax gain associated with the transaction. MAMGS owns certain gathering and processing assets located in the Mississippi Lime play, and the transaction with SemGas included a new long-term fixed-fee gathering and processing agreement covering acreage dedication areas in the Mississippi Lime play.

On May 8, 2013, CMD sold its wholly owned subsidiary, Granite Wash Midstream Gas Services, L.L.C. (GWMGS), to MarkWest Oklahoma Gas Company, L.L.C., a wholly owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE), for net proceeds of approximately $252 million, subject to post-closing adjustments. We recorded a $105 million pre-tax gain associated with this transaction. GWMGS owns certain midstream assets in the Anadarko Basin that service the Granite Wash and Hogshooter formations. The transaction with MWE included new long-term fixed-fee agreements for gas gathering, compression, treating and processing services.

On March 8, 2013, CMD sold its interest in certain gathering system assets in Pennsylvania to Western Gas Partners, LP (NYSE:WES) for net proceeds of approximately $134 million. We recorded a $55 million pre-tax gain associated with this transaction.

Liquidity and Capital Resources

Liquidity Overview

As of September 30, 2013, we had approximately $5.178 billion in cash availability (defined as unrestricted cash on hand plus borrowing capacity under our revolving bank credit facilities) compared to $4.338 billion as of December 31, 2012. During the Current Period, we decreased our debt, net of unrestricted cash, by approximately $584 million, to $11.749 billion. As of September 30, 2013, we had negative working capital of approximately $1.684 billion compared to negative working capital of approximately $2.854 billion (excluding current maturity of debt) as of December 31, 2012. Working capital deficits have historically existed because our capital spending generally has exceeded our cash flow from operations.

Our business is capital intensive. During the Current Period, our capital expenditures exceeded cash flow from operations, and we filled this spending gap with borrowings and proceeds from our joint venture and sales of assets that we determined were noncore or did not fit our long-term plans. The full year 2013 gap between forecasted capital expenditures and expected cash flows from operations is approximately $3.5 billion; however, this expected spending gap has been fully covered by joint venture and asset sales proceeds received year to date. In addition, as of September 30, 2013, we had full availability under our corporate revolving bank credit facility, providing significant additional liquidity if necessary.

Proceeds from any asset sales completed during the remainder of the year may be used to reduce financial leverage and complexity and further enhance our liquidity. While furthering our strategic priorities, certain actions that would reduce financial leverage and complexity could negatively impact our future results of operations if we incur impairments of fixed assets, lease termination charges, financing extinguishment costs or other such charges.

To add more certainty to our future estimated cash flows, we currently have downside price protection, in the form of over-the-counter derivative contracts, on approximately 80% of our remaining 2013 estimated natural gas production at an average price of $3.69 per mcf and 91% of our remaining 2013 estimated oil production at an average price of $95.59 per bbl. We also have derivative contracts providing downside price protection in 2014 on 251 bcf of natural gas at an average price of $4.22 per mcf and 22 mmbbls of oil at an average price of $93.79 per bbl. See Quantitative and Qualitative Disclosures about Market Risk in Item 3 of Part 1 of this report. Our use of derivative contracts allows us to reduce the effect of price volatility on our cash flows and EBITDA (defined as earnings before interest, taxes, depreciation, depletion and amortization), but the amount of estimated production subject to derivative contracts for any period depends on our outlook on future prices and risk assessment.

As part of our asset sales planning and capital expenditure budgeting process, we closely monitor the resulting effects on the amounts and timing of our sources and uses of funds, particularly as they affect our ability to maintain compliance with the financial covenants of our corporate revolving bank credit facility. While asset sales enhance our ability to reduce debt, sales of producing natural gas and oil properties may adversely affect the amount of cash flow and EBITDA we generate in future periods and reduce the amount and value of collateral available to secure our obligations, both of which can be exacerbated by low prices for our production. In September 2012, we obtained an amendment to our corporate revolving bank credit facility agreement that increased the required 4.00 to 1.00 indebtedness to EBITDA ratio for the quarter ended September 30, 2012 and the four subsequent quarters. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for discussion of the terms of the amendment and the early termination of its provisions on June 28, 2013. For the quarter ended September 30, 2013 and the three previous quarters, our indebtedness to EBITDA ratio was less than 4.00 to 1.00, the ratio currently in effect and which existed prior to the amendment. Failure to maintain compliance with the covenants of our revolving bank credit facility agreement could result in the acceleration of outstanding indebtedness under the facility and lead to cross defaults under our senior note and contingent convertible senior note indentures, secured hedging facility, equipment master lease agreements and term loan.

Based upon our 2013 capital expenditure budget, our forecasted operating cash flow and projected levels of indebtedness, we are projecting that we will be in compliance with the financial maintenance covenants of our corporate revolving bank credit facility. Further, we expect to meet in the ordinary course of business other contractual cash commitments to third parties pursuant to various agreements described in Contractual Obligations and Off-Balance Sheet Arrangements below and in Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, recognizing that we may be required to meet such commitments even if our business plan assumptions were to change. We believe the assumptions underlying our budget for this period are reasonable and that we have adequate flexibility, including the ability to adjust discretionary capital expenditures and other spending to adapt to potential negative developments if needed.

Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Period and the Prior Period. See Recent Sales above and Notes 6, 8, 9 and 11 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of sales of natural gas and oil assets, other assets, investments, and preferred interests and noncontrolling interests in subsidiaries.

	Nine Months Ended September 30,	
	2013	2012
	($ in millions)	
Cash provided by operating activities	$3,561	$1,978
Sales of natural gas and oil assets:		
Natural gas and oil properties	2,741	1,473
Volumetric production payment	—	744
Joint venture leasehold	48	228
Total sales of natural gas and oil assets	2,789	2,445
Other sources of cash and cash equivalents:		
Sales of other property and equipment	796	219
Sale of preferred interest and ORRI in CHK C-T	—	1,250
Proceeds from credit facility borrowings, net	—	372
Proceeds from long-term debt, net	2,274	5,052
Proceeds from sales of investments	115	2,000
Other	208	17
Total other sources of cash and cash equivalents	3,393	8,910
Total sources of cash and cash equivalents	$9,743	$13,333

Cash provided by operating activities was $3.561 billion in the Current Period compared to $1.978 billion in the Prior Period. The increase in cash provided by operating activities is primarily the result of an increase in realized natural gas and oil prices (excluding the effect of unrealized gains or losses on derivatives and partially offset by lower NGL prices) from $3.95 per mcfe in the Prior Period to $4.74 per mcfe in the Current Period, an increase in oil and NGL sales volumes and decreases in certain of our operating expenses per unit. Changes in cash flow from operations are largely due to the same factors that affect our net income, excluding various non-cash items such as depreciation, depletion and amortization, impairments of natural gas and oil properties and other assets, deferred income taxes and mark-to-market changes in our derivative instruments. See the discussion below under Results of Operations.

The following table reflects the proceeds received from issuances of debt in the Current Period and Prior Period. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

	Nine Months Ended September 30,			
	2013		2012	
	Principal Amount of Debt Issued	Net Proceeds	Principal Amount of Debt Issued	Net Proceeds
	($ in millions)			
Senior notes	$2,300	$2,274	$1,300	$1,263
Term loans	—	—	4,000	3,789
Total	$2,300	$2,274	$5,300	$5,052

Our $4.0 billion corporate revolving bank credit facility, our $500 million oilfield services revolving bank credit facility and cash and cash equivalents are other sources of liquidity. We use these revolving bank credit facilities and cash on hand to fund daily operating activities and capital expenditures as needed. We borrowed $7.136 billion and repaid $7.268 billion in the Current Period and borrowed $13.986 billion and repaid $13.614 billion in the Prior Period under our revolving bank credit facilities. Our corporate facility is secured by natural gas and oil proved reserves. A significant portion of our natural gas and oil reserves is currently unencumbered and therefore available to be pledged as additional collateral if needed to respond to borrowing base and collateral redeterminations our lenders might make in the future. We believe our borrowing capacity under this facility will not be reduced as a result of any such future redeterminations. Our oilfield services facility is secured by substantially all of our wholly owned oilfield services assets and is not subject to periodic borrowing base redeterminations. Prior to June 15, 2012, we also had a $600 million midstream revolving bank credit facility, which we terminated in June 2012. Our revolving bank credit facilities are described below under Bank Credit Facilities.

Uses of Funds

The following table presents the uses of our cash and cash equivalents for the Current Period and the Prior Period:

	Nine Months Ended September 30,	
	2013	2012
	($ in millions)	
Natural Gas and Oil Expenditures:		
Drilling and completion costs[(a)(b)]	$(4,435)	$(7,360)
Acquisitions of proved properties	(26)	(340)
Acquisitions of unproved properties	(213)	(1,850)
Geological and geophysical costs[(b)]	(36)	(165)
Interest capitalized on unproved properties	(571)	(623)
Total natural gas and oil expenditures	(5,281)	(10,338)
Other Uses of Cash and Cash Equivalents:		
Additions to other property and equipment	(639)	(1,916)
Payments on credit facility borrowings, net	(132)	—
Cash paid to purchase debt	(2,116)	—
Cash paid for prepayment of mortgage	(55)	—
Dividends paid	(303)	(298)
Cash paid to purchase preferred shares of subsidiary	(212)	—
Distributions to noncontrolling interest owners	(164)	(163)
Cash paid for financing derivatives[(c)]	(62)	(36)
Additions to investments	(8)	(261)
Other	(71)	(530)
Total other uses of cash and cash equivalents	(3,762)	(3,204)
Total uses of cash and cash equivalents	$(9,043)	$(13,542)

(a) Net of $669 million and $655 million in drilling and completion carries received from our joint venture partners during the Current Period and the Prior Period, respectively.

(b) Includes related capitalized interest.

(c) Reflects derivatives deemed to contain, for accounting purposes, a significant financing element at contract inception.

Our primary use of funds is for capital expenditures related to exploration and development of natural gas and oil properties. Historically, a significant use was also for the acquisition of leasehold and construction and acquisition of other property and equipment. During the Prior Period, our operated rig count was as high as 165 rigs as we were quickly ramping up our liquids-focused drilling while, at the same time, we were gradually ramping down drilling of natural gas wells. During the Current Period, our average rig count was 75 operated rigs, and as of October 31, 2013, our rig count was 57 operated rigs. Our natural gas drilling activities have been sharply reduced since 2012, from 50 rigs at the beginning of 2012 to an average of nine rigs in the Current Period. The Prior Period drilling and completion expenditures also reflected significant well completion costs for natural gas wells that had been drilled, but not completed, in prior periods. These completions enabled us to hold by production the related leasehold according to the terms of our leases.

Our unproved property leasehold acquisition costs during the Prior Period were $1.850 billion, approximately 60% of which were focused on adding to our acreage in the Utica and Mississippi Lime plays to complete our leasehold acquisition strategies in connection with completed or planned joint ventures in those areas.

Capital expenditures related to additions to property and equipment associated with our midstream, oilfield services and other fixed assets of $1.916 billion during the Prior Period were primarily related to the expansion of our gathering systems and the growth of our oilfield services businesses, in particular our hydraulic fracturing business. The $1.277 billion reduction of such expenditures in the Current Period is primarily the result of our sale of substantially all of our midstream business in December 2012 and a reduction in capital expenditures for our oilfield services business.

We paid dividends on our common stock of $175 million and $170 million in the Current Period and the Prior Period, respectively. We paid dividends on our preferred stock of $128 million in the Current Period and in the Prior Period.

Bank Credit Facilities

During the Current Period, we had two revolving bank credit facilities as sources of liquidity.

	Corporate Credit Facility[a]	Oilfield Services Credit Facility[b]
	($ in millions)	
Facility structure	Senior secured revolving	Senior secured revolving
Maturity date	December 2015	November 2016
Borrowing capacity	$4,000	$500
Amount outstanding as of September 30, 2013	$—	$285
Letters of credit outstanding as of September 30, 2013	$23	$—

(a) Co-borrowers are Chesapeake Exploration, L.L.C., Chesapeake Appalachia, L.L.C. and Chesapeake Louisiana, L.P.

(b) Borrower is Chesapeake Oilfield Operating, L.L.C. (COO).

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, our credit facilities do not contain provisions which would trigger an acceleration of amounts due under the respective facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

Corporate Credit Facility. Our $4.0 billion syndicated revolving bank credit facility is used for general corporate purposes. Borrowings under the facility are secured by proved reserves and bear interest at a variable rate. We were in compliance with all covenants under the credit facility agreement as of September 30, 2013. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the terms of our corporate credit facility, including the terms of an amendment that increased the required indebtedness to EBITDA ratio as of September 30, 2012 and the subsequent two quarters.

Our indebtedness to EBITDA ratio as of September 30, 2013 was approximately 2.75 to 1.00. The ratio compares consolidated indebtedness to consolidated EBITDA, both non-GAAP financial measures that are defined in the credit facility agreement, for the 12-month period ending on the measurement date. Consolidated indebtedness consists of outstanding indebtedness, less the cash and cash equivalents of Chesapeake and certain of our subsidiaries. Consolidated EBITDA consists of the net income of Chesapeake and certain of our subsidiaries, excluding income from investments and non-cash income plus interest expense, taxes, depreciation, amortization expense and other non-cash expenses, and is calculated on a pro forma basis to give effect to any acquisitions, divestitures or other adjustments.

Oilfield Services Credit Facility. Our $500 million syndicated oilfield services revolving bank credit facility is used to fund capital expenditures and for general corporate purposes associated with our oilfield services operations. The facility may be expanded from $500 million to $900 million at COO's option, subject to additional bank participation. Borrowings under the credit facility bear interest at a variable interest rate and are secured by all of the equity interests and assets of COO and its wholly owned subsidiaries (the restricted subsidiaries for this facility, which are unrestricted subsidiaries under Chesapeake's senior notes, contingent convertible senior notes, term loan, corporate revolving bank credit facility, secured hedging facility and equipment master lease agreements). For further discussion of the terms of our oilfield services credit facility, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Hedging Facility

We have a multi-counterparty secured hedging facility with 16 counterparties that have committed to provide approximately 6.4 tcfe of hedging capacity for natural gas, oil and NGL price derivatives and 6.4 tcfe for basis derivatives with an aggregate mark-to-market capacity of $17.0 billion under the terms of the facility. For further discussion of the terms of our hedging facility, see Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Term Loan

In November 2012, we established an unsecured five-year term loan credit facility in an aggregate principal amount of $2.0 billion for net proceeds of $1.935 billion. Our obligations under the facility rank equally with our outstanding senior notes and contingent convertible senior notes and are unconditionally guaranteed on a joint and several basis by our direct and indirect wholly owned subsidiaries that are subsidiary guarantors under the indentures for such notes. Amounts borrowed under the facility bear interest at a variable rate and the facility may be voluntarily repaid at any time, subject to applicable premiums, as provided in the agreement. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

Senior Note Obligations

In addition to outstanding borrowings under our revolving bank credit facilities and the term loan discussed above, our long-term debt consisted of the following as of September 30, 2013:

	September 30, 2013
	($ in millions)
9.5% senior notes due 2015	$1,265
3.25% senior notes due 2016	500
6.25% euro-denominated senior notes due 2017[(a)]	465
6.5% senior notes due 2017	660
6.875% senior notes due 2018	97
7.25% senior notes due 2018	669
6.625% senior notes due 2019[(b)]	650
6.625% senior notes due 2020	1,300
6.875% senior notes due 2020	500
6.125% senior notes due 2021	1,000
5.375% senior notes due 2021	700
5.75% senior notes due 2023	1,100
2.75% contingent convertible senior notes due 2035[(c)]	396
2.5% contingent convertible senior notes due 2037[(c)]	1,168
2.25% contingent convertible senior notes due 2038[(c)]	347
Discount on senior notes[(d)]	(346)
Interest rate derivatives[(e)]	14
Total senior notes, net	$10,485

(a) The principal amount shown is based on the exchange rate of $1.3527 to €1.00 as of September 30, 2013. See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our related foreign currency derivatives.

(b) Issuers are COO, an indirect wholly owned subsidiary of the Company, and Chesapeake Oilfield Finance, Inc. (COF), a wholly owned subsidiary of COO formed solely to facilitate the offering of the 6.625% Senior Notes due 2019. COF is nominally capitalized and has no operations or revenues. Chesapeake Energy Corporation is the issuer of all other senior notes and the contingent convertible senior notes.

(c) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty

72

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.

(d) Included in this discount was $322 million as of September 30, 2013 associated with the equity component of our contingent convertible senior notes. This discount is amortized based on an effective yield method.

(e) See Note 7 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for discussion related to these instruments.

For further discussion and details regarding our senior notes, contingent convertible senior notes and COO senior notes, see Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

Credit Risk

Derivative instruments that enable us to manage our exposure to natural gas, oil and NGL prices and interest rate volatility expose us to credit risk from our counterparties. To mitigate this risk, we enter into derivative contracts only with counterparties that are rated investment grade and 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 derivative activities, we have experienced a counterparty default only once (Lehman Brothers in September 2008), and the total loss recorded in that instance was immaterial. As of September 30, 2013, our natural gas, oil and interest rate derivative instruments were spread among 15 counterparties. Additionally, the counterparties under our multi-counterparty secured hedging facility are required to secure their obligations in excess of defined thresholds. We use this facility for substantially all of our natural gas, oil and NGL derivatives.

Our accounts receivable are primarily from purchasers of natural gas, oil and NGL ($1.662 billion as of September 30, 2013) and exploration and production companies that own interests in properties we operate ($622 million as of September 30, 2013). 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 Period and the Prior Period, we recognized nominal amounts of bad debt expense related to potentially uncollectible receivables.

Contractual Obligations and Off-Balance Sheet Arrangements

From time to time, we enter into arrangements and transactions that can give rise to off-balance sheet obligations. As of September 30, 2013, these arrangements and transactions included (i) operating lease agreements, (ii) VPPs (to physically deliver and purchase volumes and pay related production expenses and taxes in the future), (iii) open purchase commitments, (iv) open delivery commitments, (v) open drilling commitments, (vi) undrawn letters of credit, (vii) open gathering and transportation commitments and (viii) various other commitments we enter into in the ordinary course of business that could result in a future cash obligation.

As the operator of the properties from which VPP volumes have been sold, we have the responsibility to bear the cost of producing the reserves attributable to such interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods such costs are incurred. As with all non-expense-bearing royalty interests, volumes conveyed in a VPP transaction are excluded from our estimated proved reserves; however, the estimated production expenses and taxes associated with VPP volumes expected to be delivered in future periods are included as a reduction of the future net cash flows attributable to our proved reserves for purposes of determining the cost center ceiling for impairment purposes and in determining our standardized measure. Our commitment to bear the costs on any future production of VPP volumes is not reflected as a liability on our balance sheet. The costs that will apply in the future will depend on the actual production volumes as well as the production costs and taxes in effect during the periods in which such production actually occurs, which could differ materially from our current and historical costs, and production may not occur at the times or in the quantities projected, or at all. We have committed to purchase natural gas and liquids associated with our VPP transactions. Production purchased under these arrangements is based on market prices at the time of production, and the purchased natural gas and liquids are resold at market prices.

See Notes 4, 8 and 10 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of commitments, VPPs and VIEs, respectively.

Results of Operations - Three Months Ended September 30, 2013 vs. September 30, 2012

General. For the Current Quarter, Chesapeake had net income of $240 million, or $0.24 per diluted common share, on total revenues of $4.867 billion. This compares to a net loss of $1.971 billion, or $3.19 per diluted common share, on total revenues of $2.970 billion during the Prior Quarter.

Natural Gas, Oil and NGL Sales. During the Current Quarter, natural gas, oil and NGL sales were $1.586 billion compared to $1.437 billion in the Prior Quarter. In the Current Quarter, Chesapeake produced 372 bcfe at a weighted average price of $4.78 per mcfe, compared to 381 bcfe produced in the Prior Quarter at a weighted average price of $4.04 per mcfe (weighted average prices exclude the effect of unrealized losses on derivatives of $191 million and $104 million in the Current Quarter and the Prior Quarter, respectively). The increase in the price received per mcfe in the Current Quarter compared to the Prior Quarter resulted in an increase in revenues of $273 million, and decreased sales volumes resulted in a $37 million decrease in revenues, for a total increase in revenues of $236 million (excluding unrealized gains or losses on natural gas, oil and NGL derivatives).

For the Current Quarter, we realized an average price per mcf of natural gas of $2.26 compared to $1.97 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 $92.09 and $90.79 in the Current Quarter and the Prior Quarter, respectively. NGL prices realized per barrel (excluding unrealized gains or losses on derivatives) were $26.52 and $31.22 in the Current Quarter and the Prior Quarter, respectively. Realized gains and losses from our natural gas, oil and NGL derivatives resulted in a net decrease in natural gas, oil and NGL revenues of $62 million, or $0.16 per mcfe, in the Current Quarter and a net increase of $77 million, or $0.20 per mcfe, in the Prior Quarter. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of September 30, 2013.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming the Current Quarter production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $27 million, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in Current Quarter revenues and cash flows of approximately $16 million without considering the effect of hedging activities.

Our company-wide reorganization in the Current Quarter resulted in two operating divisions replacing the four operating divisions we previously reported. The following tables show our production and average sales prices received by operating division for the Current Quarter and the Prior Quarter:

	Three Months Ended September 30, 2013								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	164.5	2.16	9.8	101.57	4.2	26.81	248.4	67	5.90
Northern[c]	108.8	2.06	1.2	97.10	1.2	25.52	123.5	33	3.02
Total[d]	273.3	2.12	11.0	101.08	5.4	26.52	371.9	100 %	4.94

	Three Months Ended September 30, 2012								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	235.9	1.72	8.7	88.27	3.7	30.66	310.3	82	4.16
Northern[c]	66.4	2.06	0.3	81.43	0.4	35.74	70.8	18	2.47
Total[d]	302.3	1.80	9.0	88.07	4.1	31.22	381.1	100 %	3.84

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

(b) Our Southern Division includes the Eagle Ford, Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 21% of our estimated proved reserves by volume as of December 31, 2012. Production for the Eagle Ford Shale for the Current Quarter and the Prior Quarter was 53 bcfe and 31 bcfe, respectively.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play. The Marcellus Shale accounted for approximately 23% of our estimated proved reserves by volume as of December 31, 2012. Production for the Marcellus Shale for the Current Quarter and the Prior Quarter was 102 bcfe and 62 bcfe, respectively.

(d) Current Quarter and Prior Quarter production reflects various asset sales. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our natural gas and oil property divestitures.

Our average daily production of 4.0 bcfe for the Current Quarter consisted of approximately 3.0 bcfe of natural gas (73% on a natural gas equivalent basis) and approximately 178,500 bbls of liquids, consisting of approximately 120,000 bbls of oil (18% on a natural gas equivalent basis) and approximately 58,500 bbls of NGL (9% on a natural gas equivalent basis). Our year-over-year growth rate of oil production was 23% and our year-over-year growth rate of NGL production was 31%. Natural gas production declined 10% year over year primarily as a result of asset sales.

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake primarily for owners in Chesapeake-operated wells. Chesapeake recognized $3.032 billion in marketing, gathering and compression revenues in the Current Quarter with corresponding expenses of $3.009 billion, for a net margin before depreciation of $23 million. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. This compares to revenues of $1.381 billion, expenses of $1.339 billion and a net margin before depreciation of $42 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in marketing, gathering and compression revenues and expenses primarily due to a substantial increase in oil volumes purchased from third parties and resold, an increase in crude oil prices, and an increase in compression services, offset by the loss of activity from the sale of substantially all of our gathering business in the 2012 fourth quarter. Our gathering business provided approximately $4 million and $16 million of the total marketing, gathering and compression net margin, or 19% and 38%, in the Current Quarter and the Prior Quarter, respectively.
Oilfield Services Revenues and Expenses. Oilfield services consist of third-party revenues and expenses related to our oilfield services operations. Chesapeake recognized $249 million in oilfield services revenues in the Current Quarter with corresponding expenses of $211 million, for a net margin before depreciation of $38 million. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our oilfield services assets. This compares to revenues of $152 million, expenses of $116 million and a net margin before depreciation of $36 million in the Prior Quarter. Oilfield services revenues and expenses increased from the Prior Quarter to the Current Quarter primarily as a result of the growth in our hydraulic fracturing business; however, these increases were offset by a decrease in rates and activity of our drilling and oilfield tool and equipment rental subsidiaries.
Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $282 million in the Current Quarter, compared to $320 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.76 per mcfe in the Current Quarter compared to $0.84 per mcfe in the Prior Quarter. The per unit expense decrease in the Current Quarter was primarily the result of a general improvement in operating efficiencies across most of our operating areas as well as lower saltwater disposal costs and the divestiture in the 2012 fourth quarter of our Permian Basin assets, which had comparatively high operating costs per unit of production. Production expenses in the Current Quarter and the Prior Quarter included approximately $46 million and $55 million, or $0.12 and $0.14 per mcfe, respectively, associated with VPP production volumes.
Production Taxes. Production taxes were $62 million in the Current Quarter compared to $53 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.17 per mcfe in the Current Quarter compared to $0.14 per mcfe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas, oil and NGL prices are higher. The $9 million increase in production taxes in the Current Quarter was primarily due to the increase in the unhedged price of our production from $3.84 per mcfe to $4.94 per mcfe. Production taxes in the Current Quarter and the Prior Quarter included approximately $6 million and $5 million, respectively, or $0.01 per mcfe, associated with VPP production volumes.
General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding restructuring charges and internal costs capitalized to our natural gas and oil properties and other property, plant and equipment, were $120 million in the Current Quarter and $145 million in the Prior Quarter, or $0.32 and $0.38 per mcfe, respectively. The per unit expense decrease in the Current Quarter was primarily due to our efforts to reduce our cost structure and increased emphasis on operational efficiencies. Included in general and administrative expenses is stock-based compensation of $13 million in the Current Quarter and $17 million in the Prior Quarter. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion 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, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with acquisition of leasehold and drilling and completion 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 $79 million and $112

million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our natural gas and oil property acquisition, drilling and completion efforts and the construction of our property, plant and equipment. The decrease was primarily due to our cost structure initiatives and increased emphasis on operational efficiencies.

Restructuring and Other Termination Benefits. We recorded $63 million and $3 million of restructuring and other termination benefits in the Current Quarter and the Prior Quarter, respectively. The Current Quarter amount primarily related to workforce reductions, senior management separations and our voluntary separation plan. The Prior Quarter amount related to other termination benefits. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

The Company committed to a workforce reduction plan in September 2013 that resulted in a reduction of approximately 900 employees. In connection with the workforce reduction plan, we expect to incur a total cost of $70 million, of which approximately $31 million was recorded in the Current Quarter for employees terminated in September 2013, and we expect to recognize the remaining $39 million in the 2013 fourth quarter for employees terminated in October 2013. The acceleration of vesting of stock-based compensation accounted for approximately $25 million of this expense in the Current Quarter, and we project additional expense of $20 million for acceleration of vesting of stock-based compensation in the 2013 fourth quarter. Of the $31 million in charges incurred in the Current Quarter under the workforce reduction plan, approximately $1 million was paid in the Current Quarter. We also incurred a one-time charge of approximately $28 million in the Current Quarter related to the separation from the Company of certain other employees, including executive officers, that were outside the workforce reduction plan.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $652 million and $762 million in the Current Quarter and the Prior Quarter, respectively. The $110 million decrease in the Current Quarter is primarily the result of the ceiling test impairment recorded in the Prior Quarter, which decreased the net book value of our proved properties. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information regarding the impairment. 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 $1.75 and $2.00 in the Current Quarter and the Prior Quarter, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $79 million in the Current Quarter, compared to $66 million in the Prior Quarter. Depreciation and amortization of other assets was $0.21 and $0.17 per mcfe in the Current Quarter and the Prior Quarter, respectively. The per unit increase in the Current Quarter is primarily due to lower production levels in the Current Quarter compared to the Prior Quarter and additional depreciation of increased hydraulic fracturing equipment during the Current Quarter compared to the Prior Quarter. See Note 1 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information regarding our assets held for sale.

Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment is used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) is capitalized in natural gas and oil properties as drilling and completion costs. The following table shows depreciation expense by asset class for the Current Quarter and Prior Quarter and the estimated useful lives of our assets.

	Three Months Ended September 30, 2013	2012	Estimated Useful Life
	($ in millions)		(in years)
Oilfield services equipment[(a)]	$33	$19	3 - 15
Natural gas gathering systems and treating plants[(b)]	3	3	20
Buildings and improvements	11	10	10 - 39
Natural gas compressors[(b)]	10	7	3 - 20
Computers and office equipment	10	11	3 - 7
Vehicles	9	12	0 - 5
Other	3	4	2 - 20
Total depreciation and amortization of other assets	$79	$66	

(a) Included in our oilfield services operating segment.

(b) Included in our marketing, gathering and compression operating segment.

Impairment of Natural Gas and Oil Properties. In the Prior Quarter, we reported a non-cash impairment charge on our natural gas and oil properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012 compared to June 30, 2012, and the impairment of certain undeveloped leasehold, primarily in the Williston and DJ Basins. 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 pricing and cost assumptions prescribed by the SEC and the present value of certain natural gas and oil derivative instruments. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our impairment of natural gas and oil properties.

Impairments of Fixed Assets and Other. In the Current Quarter and Prior Quarter, we recognized $85 million and $38 million, respectively, of impairment losses associated with fixed assets and other, primarily related to gathering systems and drilling rigs. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our impairments of fixed assets and other.

Net (Gains) Losses on Sales of Fixed Assets. In the Current Quarter, net gains on sales of fixed assets were $132 million compared to net losses of $7 million in the Prior Quarter. The Current Quarter gains primarily related to the sale of certain of our midstream gathering systems. See Note 11 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our net (gains) losses on sales of fixed assets.

Interest Expense. Interest expense was $40 million in the Current Quarter compared to $36 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2013	2012
	($ in millions)	
Interest expense on senior notes	$180	$187
Interest expense on credit facilities	8	13
Interest expense on term loans	29	112
Realized (gains) losses on interest rate derivatives	(3)	—
Unrealized (gains) losses on interest rate derivatives	—	(2)
Amortization of loan discount, issuance costs and other	21	24
Capitalized interest	(195)	(298)
Total interest expense	$40	$36
Average senior notes borrowings	$10,847	$10,257
Average term loan borrowings	$2,000	$4,000
Average credit facilities borrowings	$348	$1,469

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.11 per mcfe in the Current Quarter compared to $0.10 per mcfe in the Prior Quarter. The increase in interest expense is primarily due to a decrease in the amount of interest capitalized as a result of a decrease in the average balance of our unevaluated natural gas and oil properties.

Losses on Investments. Losses on investments were $22 million in the Current Quarter, compared to losses on investments of $23 million in the Prior Quarter. The Current Quarter loss primarily related to our equity in the net loss of FTS International, Inc. (FTS). The Prior Quarter losses related primarily to our equity in the net loss of FTS, offset by earnings related to our equity in the net income of Access Midstream Partners, L.P. (NYSE:ACMP), formerly named Chesapeake Midstream Partners, L.P. See Note 9 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our investments.

Gains on Sales of Investments. In the Current Quarter and Prior Quarter, we recorded gains on sales of investments of $3 million and $31 million, respectively. In the Current Quarter, we sold all of our shares of Clean Energy Fuels Corp. (Clean Energy) common stock for cash proceeds of approximately $13 million. In the Prior Quarter, we sold 50% of our investment in Glass Mountain Pipeline, LLC for cash proceeds of $47 million.

Other Income (Expense). We recorded $10 million of other income in the Current Quarter compared to $9 million of other expense in the Prior Quarter. Other income in the Current Quarter consisted of $2 million of interest income and $8 million of miscellaneous income. Other expense in the Prior Quarter consisted of $9 million of miscellaneous expense.

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $147 million in the Current Quarter compared to an income tax benefit of $1.260 billion in the Prior Quarter. Our effective income tax rate was 38% in the Current Quarter and 39% in the Prior Quarter. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded $38 million and $41 million of net income attributable to noncontrolling interests in the Current Quarter and the Prior Quarter, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on our CHK Utica and CHK C-T preferred stock in addition to income or loss related to the Chesapeake Granite Wash Trust. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of these entities.

Results of Operations - Nine Months Ended September 30, 2013 vs. September 30, 2012

General. For the Current Period, Chesapeake had net income of $967 million, or $0.96 per diluted common share, on total revenues of $12.965 billion. This compares to a net loss of $938 million, or $1.86 per diluted common share, on total revenues of $8.778 billion during the Prior Period.

Natural Gas, Oil and NGL Sales. During the Current Period, natural gas, oil and NGL sales were $5.444 billion compared to $4.622 billion in the Prior Period. In the Current Period, Chesapeake produced 1.099 tcfe at a weighted average price of $4.74 per mcfe, compared to 1.061 tcfe produced in the Prior Period at a weighted average price of $3.95 per mcfe (weighted average prices exclude the effect of unrealized gains on derivatives of $237 million and $436 million in the Current Period and the Prior Period, respectively). The increase in the price received per mcfe in the Current Period compared to the Prior Period resulted in an increase in revenues of $867 million, and increased sales volumes resulted in a $154 million increase in revenues, for a total increase in revenues of $1.021 billion (excluding unrealized gains or losses on natural gas, oil and NGL derivatives). The 4% increase in production from the Prior Period to the Current Period was primarily generated through the drillbit.

For the Current Period, we realized an average price per mcf of natural gas of $2.34 compared to $2.06 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 $93.51 and $91.55 in the Current Period and the Prior Period, respectively. NGL prices realized per barrel (excluding unrealized gains or losses on derivatives) were $26.35 and $30.17 in the Current Period and the Prior Period, respectively. Realized gains and losses from our natural gas, oil and NGL derivatives resulted in a net decrease in natural gas, oil and NGL revenues of $96 million, or $0.08 per mcfe, in the Current Period and a net increase of $388 million, or $0.37 per mcfe, in the Prior Period. See Item 3 of Part I of this report for a complete listing of all of our derivative instruments as of September 30, 2013.

A change in natural gas, oil and NGL prices has a significant impact on our revenues and cash flows. Assuming the Current Period production levels, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $82 million and $80 million, respectively, and an increase or decrease of $1.00 per barrel of liquids sold would result in an increase or decrease in Current Period revenues and cash flows of approximately $46 million and $44 million, respectively, without considering the effect of hedging activities.

Our company-wide reorganization in the Current Quarter resulted in two operating divisions replacing the four operating divisions we previously reported. The following tables show our production and average sales prices received by operating division for the Current Period and the Prior Period:

	Nine Months Ended September 30, 2013								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	539.4	2.21	28.7	96.74	12.2	25.44	784.5	71	5.44
Northern[c]	284.7	2.59	2.2	92.14	2.8	30.41	314.9	29	3.28
Total[d]	824.1	2.34	30.9	96.40	15.0	26.35	1,099.4	100 %	4.82

	Nine Months Ended September 30, 2012								
	Natural Gas		Oil		NGL		Total		
	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmbbl)	($/bbl)[a]	(bcfe)	%	($/mcfe)[a]
Southern[b]	667.1	1.53	21.7	91.56	11.8	29.69	868.1	82	3.87
Northern[c]	181.5	1.86	0.6	82.61	1.2	42.23	192.4	18	2.28
Total[d]	848.6	1.60	22.3	91.31	13.0	30.86	1,060.5	100 %	3.58

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

(b) Our Southern Division includes the Eagle Ford, Granite Wash/Hogshooter, Cleveland, Tonkawa and Mississippi Lime unconventional liquids plays and the Haynesville/Bossier and Barnett unconventional natural gas shale plays. The Eagle Ford Shale accounted for approximately 21% of our estimated proved reserves by volume as of December 31, 2012. Production for the Eagle Ford Shale for the Current Period and the Prior Period was 142 bcfe and 70 bcfe, respectively.

(c) Our Northern Division includes the Utica and Niobrara unconventional liquids plays and the Marcellus unconventional natural gas play. The Marcellus Shale accounted for approximately 23% of our estimated proved reserves by volume as of December 31, 2012. Production for the Marcellus Shale for the Current Period and the Prior Period was 269 bcfe and 169 bcfe, respectively.

(d) Current Period and Prior Period production reflects various asset sales. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information on our natural gas and oil property divestitures.

Our average daily production of 4.0 bcfe for the Current Period consisted of approximately 3.0 bcfe of natural gas (75% on a natural gas equivalent basis) and approximately 168,000 bbls of liquids, consisting of approximately 113,000 bbls of oil (17% on a natural gas equivalent basis) and approximately 55,000 bbls of NGL (8% on a natural gas equivalent basis). Our year-over-year growth rate of oil production was 39% and our year-over-year growth rate of NGL production was 16%. Natural gas production declined 3% year over year primarily as a result of asset sales.

Marketing, Gathering and Compression Sales and Expenses. Marketing, gathering and compression revenues and expenses consist of third-party revenues and expenses related to our marketing, gathering and compression operations. Marketing, gathering and compression activities are performed by Chesapeake primarily for owners in Chesapeake-operated wells. Chesapeake recognized $6.871 billion in marketing, gathering and compression revenues in the Current Period with corresponding expenses of $6.781 billion, for a net margin before depreciation of $90 million. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. This compares to revenues of $3.710 billion, expenses of $3.631 billion and a net margin before depreciation of $79 million in the Prior Period. In the Current Period, Chesapeake realized an increase in marketing, gathering and compression revenues and expenses primarily due to a substantial increase in oil volumes purchased from third parties and resold, an increase in crude oil prices, and an increase in compression services, offset by the loss of activity from the sale of substantially all of our gathering business in the 2012 fourth quarter. Our gathering business provided approximately $14 million and $37 million of the total marketing, gathering and compression net margin, or 15% and 47%, in the Current Period and the Prior Period, respectively.

Oilfield Services Revenues and Expenses. Oilfield services consist of third-party revenues and expenses related to our oilfield services operations. Chesapeake recognized $650 million in oilfield services revenues in the Current Period with corresponding expenses of $543 million, for a net margin before depreciation of $107 million. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our oilfield services assets. This compares to revenues of $446 million, expenses of $321 million and a net margin before depreciation of $125 million in the Prior Period. Oilfield services revenues and expenses increased from the Prior Period to the Current Period primarily as a result of the growth in our hydraulic fracturing business; however, these increases were offset by a decrease in rates and activity of our drilling and oilfield tool and equipment rental subsidiaries.

Natural Gas, Oil and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $877 million in the Current Period, compared to $1.005 billion in the Prior Period. On a unit-of-production basis, production expenses were $0.80 per mcfe in the Current Period compared to $0.95 per mcfe in the Prior Period. The per unit expense decrease in the Current Period was primarily the result of a general improvement in operating efficiencies across most of our operating areas as well as lower saltwater disposal costs, the divestiture in the 2012 fourth quarter of our Permian Basin assets, which had comparatively high operating costs per unit of production, and a $17 million fee retroactively imposed in the Prior Period on wells drilled in Pennsylvania, which had a $0.02 per mcfe effect. Production expenses in the Current Period and the Prior Period included approximately $125 million and $172 million, or $0.11 and $0.16 per mcfe, respectively, associated with VPP production volumes.

Production Taxes. Production taxes were $173 million in the Current Period compared to $141 million in the Prior Period. On a unit-of-production basis, production taxes were $0.16 per mcfe in the Current Period compared to $0.13 per mcfe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when natural gas, oil and NGL prices are higher. The $32 million increase in production taxes in the Current Period was primarily due to the increase in the unhedged price of our production from $3.58 per mcfe to $4.82 per mcfe, in addition to an increase in production of 39 bcfe. Production taxes in the Current Period and the Prior Period included approximately $16 million and $15 million, or $0.01 and $0.01 per mcfe, respectively, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses, including stock-based compensation but excluding restructuring and other termination benefits and internal costs capitalized to our natural gas and oil properties and other property, plant and equipment, were $336 million in the Current Period and $436 million in the Prior Period, or $0.31 and $0.41 per mcfe, respectively. The per unit expense decrease in the Current Period was primarily due to our efforts to reduce our cost structure and increased emphasis on operational efficiencies, partially offset by an increase in legal expenses relating to various corporate matters. Included in general and administrative expenses is stock-based compensation of $48 million in the Current Period and $55 million in the Prior Period. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion 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, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with acquisition of leasehold and drilling and completion 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 $252 million and $346 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our natural gas and oil property acquisition, drilling and completion efforts and the construction of our property, plant and equipment. The decrease was primarily due to our cost structure initiative and increased emphasis on operational efficiencies.

Restructuring and Other Termination Benefits. We recorded $203 million and $4 million of restructuring and other termination benefits in the Current Period and the Prior Period, respectively. The Current Period amount primarily related to workforce reductions, senior management separations and our voluntary separation plan. The Prior Period related to other termination benefits. See Note 13 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion.

The Company committed to a workforce reduction plan in September 2013 that resulted in a reduction of approximately 900 employees. In connection with the workforce reduction plan, we expect to incur a total cost of $70 million, of which approximately $31 million was recorded in the Current Period for employees terminated in September 2013, and we expect to recognize the remaining $39 million in the 2013 fourth quarter for employees terminated in October 2013. The acceleration of vesting of stock-based compensation accounted for approximately $25 million of this expense in the Current Period, and we project additional expense of $20 million for acceleration of vesting of stock-based compensation in the 2013 fourth quarter. Of the $31 million in charges incurred in the Current Period under the workforce reduction plan, approximately $1 million was paid in the Current Period. We also incurred a one-time charge of approximately $172 million in the Current Period related to the separation from the Company of certain other employees, including our former CEO and other executive officers, that were outside the workforce reduction plan.

Natural Gas, Oil and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas, oil and NGL properties was $1.945 billion and $1.856 billion in the Current Period and the Prior Period, respectively. The $89 million increase in the Current Period is primarily due to a 39 bcfe, or 4%, increase in total production. 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 $1.77 and $1.75 in the Current Period and the Prior Period, respectively.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $234 million in the Current Period, compared to $233 million in the Prior Period. Depreciation and amortization of other assets was $0.21 and $0.22 per mcfe in the Current Period and the Prior Period, respectively. The per unit decrease in the Current Period is primarily due to higher production levels in the Current Period compared to the Prior Period and the sale of substantially all of our midstream business in December 2012, partially offset by additional depreciation of increased hydraulic fracturing equipment during the Current Period. See Note 1 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information regarding our assets held for sale.

Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. To the extent company-owned oilfield services equipment is used to drill and complete our wells, a substantial portion of the depreciation (i.e., the portion related to our utilization of the equipment) is capitalized in natural gas and oil properties as drilling and completion costs. The following table shows depreciation expense by asset class for the Current Period and Prior Period and the estimated useful lives of our assets.

	Nine Months Ended September 30,		Estimated Useful Life
	2013	2012	
	($ in millions)		(in years)
Oilfield services equipment[(a)]	$86	$50	3 - 15
Natural gas gathering systems and treating plants[(b)]	10	42	20
Buildings and improvements	36	31	10 - 39
Natural gas compressors[(b)]	28	18	3 - 20
Computers and office equipment	34	33	3 - 7
Vehicles	29	39	0 - 5
Other	11	20	2 - 20
Total depreciation and amortization of other assets	$234	$233	

(a) Included in our oilfield services operating segment.
(b) Included in our marketing, gathering and compression operating segment.

Impairment of Natural Gas and Oil Properties. In the Prior Period, we reported a non-cash impairment charge on our natural gas and oil properties of $3.315 billion, primarily resulting from a 10% decrease in trailing 12-month average first-day-of-the-month natural gas prices as of September 30, 2012 compared to June 30, 2012, and the impairment of certain undeveloped leasehold, primarily in the Williston and DJ Basins. 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 pricing and cost assumptions prescribed by the SEC and the present value of certain natural gas and oil derivative instruments. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of our impairment of natural gas and oil properties.

Impairments of Fixed Assets and Other. In the Current Period and the Prior Period, we recognized $343 million and $281 million, respectively, of impairment losses associated with fixed assets and other charges related to gathering systems and drilling rigs. Of the impairments, $247 million and $227 million were related to impairments of certain buildings and land in the Current Period and Prior Period, respectively. See Note 12 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our impairments of fixed assets and other.

Net (Gains) Losses on Sales of Fixed Assets. In the Current Period, net gains on sales of fixed assets were $290 million compared to net losses on sales of fixed assets of $5 million in the Prior Period. The Current Period gains primarily related to sales of certain of our midstream gathering systems. See Note 11 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of our net (gains) losses on sales of fixed assets.

Interest Expense. Interest expense was $164 million in the Current Period compared to $63 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2013	2012
	($ in millions)	
Interest expense on senior notes	$560	$546
Interest expense on credit facilities	30	51
Interest expense on term loans	87	173
Realized (gains) losses on interest rate derivatives	(6)	—
Unrealized (gains) losses on interest rate derivatives	57	(4)
Amortization of loan discount, issuance costs and other	70	67
Capitalized interest	(634)	(770)
Total interest expense	$164	$63
Average senior notes borrowings	$11,052	$10,300
Average term loan borrowings	$2,000	$2,073
Average credit facilities borrowings	$779	$2,466

Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $0.10 per mcfe in the Current Period compared to $0.06 per mcfe in the Prior Period. The increase in interest expense is primarily due to a decrease in the amount of interest capitalized as a result of a decrease in the average balance of our unevaluated natural gas and oil properties.

Losses on Investments. Losses on investments were $26 million in the Current Period, compared to losses on investments of $87 million in the Prior Period. The Current Period loss related to our equity in the net losses of our Sundrop Fuels, Inc. and FTS investments. The Prior Period losses related primarily to our equity in the net loss of FTS, offset by a gain related to our equity in the net income of ACMP.

Impairment of Investment. In the Current Period, we recorded a $10 million mark-to-market pre-tax impairment of our Gastar Exploration Ltd. investment.

Gains (Losses) on Sales of Investments. In the Current Period and Prior Period, we recorded a loss on sales of investments of $7 million and a gain on sales of investments of $1.061 billion, respectively. In the Current Period, we sold our convertible note and all of our shares related to Clean Energy for cash proceeds of $85 million and $13 million, respectively. We recorded a $15 million loss related to the sale of our Clean Energy convertible note and a $3 million gain related to the sale of our Clean Energy stock. In addition, we sold a $1 million equity investment for cash proceeds of $6 million and recorded a $5 million gain. In the Prior Period, we sold all of our common and subordinated units representing limited partner interests in ACMP and all of our limited liability company interests in the sole member of its general partner for cash proceeds of $2.0 billion. We recorded a $1.032 billion pre-tax gain associated with the transaction. Also in the Prior Period, we sold 50% of our investment in Glass Mountain Pipeline, LLC for cash proceeds of $47 million. We recorded a $31 million gain associated with the transaction.

Losses on Purchases of Debt. In the Current Period, we purchased $217 million in aggregate principal amount of our 7.625% Senior Notes due 2013 for $221 million and $377 million in aggregate principal amount of our 6.875% Senior Notes due 2018 for $405 million pursuant to tender offers which expired on April 12, 2013. We recorded a loss of approximately $37 million associated with the tender offers, including $32 million in premiums and $5 million of unamortized deferred charges. In addition, we redeemed $1.3 billion in aggregate principal amount of our 6.775% Senior Notes due 2019 at par pursuant to a notice of special early redemption. We recorded a loss of approximately $33 million associated with the redemption, including $19 million of unamortized deferred charges and $14 million of discount.

Other Income. Other income was $18 million in the Current Period and $2 million in the Prior Period. Other income in the Current Period consisted of $4 million of interest income and $14 million of miscellaneous income. Other income in the Prior Period consisted of $1 million of interest income and $1 million of miscellaneous income.

84

Income Tax Expense (Benefit). Chesapeake recorded income tax expense of $594 million in the Current Period compared to an income tax benefit of $599 million in the Prior Period. Our effective income tax rate was 38% in the Current Period and 39% in the Prior Period. Our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded $127 million and $131 million of net income attributable to noncontrolling interests in the Current Period and the Prior Period, respectively. Net income attributable to noncontrolling interests is primarily driven by the dividends paid on our CHK Utica and CHK C-T preferred stock in addition to income or loss related to the Chesapeake Granite Wash Trust. See Note 6 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a discussion of these entities.

Application of Critical Accounting Policies

We consider accounting policies related to natural gas and oil properties, derivatives, variable interest entities 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 2012 Form 10-K.

Recently Issued Accounting Standards

Recently Adopted Accounting Standards

In February 2012, the Financial Accounting Standards Board (FASB) issued guidance changing the presentation requirements of significant reclassifications out of accumulated other comprehensive income in their entirety and their corresponding effect on net income. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

In December 2011 and January 2013, the FASB issued guidance amending and expanding disclosure requirements about offsetting and related arrangements associated with derivatives. We adopted this standard in the first quarter of 2013 and it did not have a material impact on our financial statements.

Recently Issued Accounting Standards

To reduce diversity in practice related to the presentation of unrecognized tax benefits, in July 2013 the FASB issued guidance requiring the presentation of an unrecognized tax benefit in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward. This net presentation is required unless a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date or the tax law of the jurisdiction does not require, and the entity does not intend to use, the deferred tax asset to settle any additional income tax that would result from the disallowance of the unrecognized tax benefit. The guidance will be effective on January 1, 2014; retrospective application and early adoption are permitted, but not required. Because we have historically presented unrecognized tax benefits net of net operating loss carryforwards, similar tax losses or tax credit carryforwards, this standard will not impact our consolidated financial statements.

In February 2013, the FASB issued guidance on the recognition, measurement and disclosure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. We will adopt this standard effective January 1, 2014. We do not expect the adoption to have a material impact on our consolidated financial statements.

Forward-Looking Statements

This report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). Forward-looking statements give our current expectations or forecasts of future events. They include expected natural gas, oil and NGL production and future expenses, estimated operating costs, assumptions regarding future natural gas, oil and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures (including the use of joint venture drilling carries), and anticipated sales, as well as statements concerning anticipated cash flow and liquidity, covenant compliance, debt reduction, operating and capital efficiencies, business strategy and other plans and objectives for future operations. Our ability to generate sufficient operating cash flow to fund future capital expenditures is subject to all the risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time. Further, asset sales we are evaluating as we focus on our strategic priorities are subject to market conditions and other factors beyond our control. Our plans to reduce financial leverage and complexity may take longer to implement if such sales are delayed or do not occur as expected. 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 our 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 2012 Form 10-K and include:

- the volatility of natural gas, oil and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- declines in the prices of natural gas and oil potentially resulting in a write-down of our asset carrying values;
- the availability of capital on an economic basis, including through planned sales, to fund reserve replacement costs;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of natural gas, oil and NGL reserves and projecting future rates of production and the amount and timing of development expenditures;
- our ability to generate profits or achieve targeted results in drilling and well operations;
- leasehold terms expiring before production can be established;
- hedging activities resulting in lower prices realized on natural gas, oil and NGL sales;
- the need to secure hedging liabilities and the inability of hedging counterparties to satisfy their obligations;
- drilling and operating risks, including potential environmental liabilities;
- legislative and regulatory changes adversely affecting our industry and our business, including initiatives related to hydraulic fracturing, air emissions and endangered species;
- current worldwide economic uncertainty which may have a material adverse effect on our results of operations, liquidity and financial condition;
- oilfield services shortages, gathering system and transportation capacity constraints and various transportation interruptions that could adversely affect our revenues and cash flow;
- losses possible from pending or future litigation and regulatory investigations;
- cyber attacks adversely impacting our operations; and
- the loss of key operational personnel or inability to maintain our corporate culture.

We caution you not to place undue reliance on the forward-looking statements contained in this report, which speak only as of the filing date, 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 SEC 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, Oil and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for natural gas, oil and NGL. To mitigate a portion of our exposure to adverse price changes, we have entered into various derivative instruments. These instruments allow us to predict with greater certainty the effective prices to be received for our production. 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, oil and NGL price changes is to hedge into strengthening natural gas and oil futures markets when prices reach levels that management believes are either unsustainable for the long term, have material downside risk in the short term or provide reasonable rates of return on our invested capital. 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 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, options and swaptions. All of these are described in more detail below. We typically use swaps for a large portion of the natural gas and oil volume we hedge. Swaps are used when the price level is acceptable. We also sell calls, taking advantage of market volatility for a portion of our projected production volumes. We do this when we would be satisfied to sell our production at the price being capped by the call strike price or believe it would 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. In the second half of 2011 and in 2012, we bought natural gas and oil calls to, in effect, lock in sold call positions. Due to lower natural gas, oil and NGL prices, we were able to achieve this at a low cost to us. We deferred the payment of the premium on these trades to the related month of production being hedged. Some of our derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception and the cash settlements associated with these instruments are classified as financing cash flows in the accompanying condensed consolidated statement of cash flows.

We determine the volume potentially subject to derivative contracts by reviewing our overall 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 enter into derivative contracts for more volumes than our forecasted production, and if production estimates are lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions are reversed. The actual fixed 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 as stated in the contract and the floating-price payment, resulting in a net amount due to or from the counterparty.

We adjust our derivative positions in response to changes in prices and market conditions as part of an ongoing dynamic process. We review our derivative positions continuously and if future market conditions change and prices are at levels we believe could jeopardize the effectiveness of a position, we will mitigate such risk by either negotiating a cash settlement with our counterparty, restructuring the position or entering into a new trade that effectively reverses the current position. 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 derivative position. Gains or losses related to closed positions will be realized in the month of related production based on the terms specified in the original contract.

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 partially 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. See Note 14 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of the fair value measurements associated with our derivatives.
As of September 30, 2013, our natural gas and oil derivative instruments consisted of the following:

- Swaps: Chesapeake receives a fixed price and pays a floating market price to the counterparty for the hedged commodity.
- Options: Chesapeake sells, and occasionally buys, call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess on sold call options, and Chesapeake receives such excess on bought call options. If the market price settles below the fixed price of the call options, no payment is due from either party.
- Swaptions: Chesapeake sells call swaptions in exchange for a premium that allows a counterparty, on a specific date, to enter into a fixed-price swap for a certain period of time.
- Basis Protection Swaps: These instruments are arrangements that guarantee a price differential to NYMEX from a specified delivery point. Our natural gas basis protection swaps 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. Our oil basis protection swaps 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.
- 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.

As of September 30, 2013, we had the following open natural gas and oil derivative instruments:

	Volume (tbtu)	Weighted Average Price Fixed ($ per mmbtu)	Call	Put	Differential	Fair Value Asset (Liability) ($ in millions)
Natural Gas:						
Swaps:						
Q4 2013	190	3.71	—	—	—	$21
2014	151	4.35	—	—	—	75
Call Options (sold):						
Q4 2013	68	—	6.39	—	—	—
2014	330	—	6.43	—	—	(2)
2015	226	—	6.31	—	—	(11)
2016 – 2020	393	—	7.93	—	—	(32)
Call Options (bought)[a]:						
Q4 2013	(68)	—	6.39	—	—	(3)
2014	(330)	—	6.43	—	—	(39)
2015	(226)	—	6.31	—	—	(71)
2016	(200)	—	6.02	—	—	(61)
Swaptions:						
2014	12	4.80	—	—	—	—
Basis Protection Swaps:						
Q4 2013	11	—	—	—	(0.21)	—
2014	28	—	—	—	(0.32)	—
2015	31	—	—	—	(0.34)	3
2016 – 2022	9	—	—	—	(1.02)	(5)
3-Way Collars:						
Q4 2013	18	—	4.03	3.03/3.55	—	1
2014	18	—	4.70	3.50/4.00	—	3
Total Natural Gas						$(121)

89

	Volume	Weighted Average Price Fixed	Call	Put	Differential	Fair Value Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Swaps:						
Q4 2013	9.2	95.60	—	—	—	$(55)
2014	21.7	93.79	—	—	—	(39)
2015	0.7	89.47	—	—	—	—
Call Options (sold):						
Q4 2013	4.3	—	94.04	—	—	(38)
2014	16.9	—	96.92	—	—	(101)
2015	24.7	—	100.45	—	—	(114)
2016 – 2017	24.2	—	100.07	—	—	(118)
Call Options (bought)[b]:						
Q4 2013	(2.3)	—	90.80	—	—	7
2014	(2.2)	—	94.91	—	—	(4)
Swaptions:						
2014	2.9	106.69	—	—	—	(1)
2015	2.4	106.61	—	—	—	—
Basis Protection Swaps:						
2013 – 2014	0.5	—	—	—	6.00	1
	Total Oil					$(462)
	Total Natural Gas and Oil					$(583)

(a) Included in the fair value are deferred premiums of $3 million, $41 million, $82 million and $84 million which we will realize in 2013, 2014, 2015 and 2016, respectively.

(b) Included in the fair value are deferred premiums of $21 million and $19 million which we will realize in 2013 and 2014, respectively.

In addition to the open derivative positions disclosed above, as of September 30, 2013, we had $89 million of net hedging gains related to settled trades for future production periods that will be recorded within natural gas, oil and NGL sales as realized gains (losses) as they are transferred from either accumulated other comprehensive income or unrealized gains (losses) in the month of related production based on the terms specified in the original contract as noted below.

	September 30, 2013
	($ in millions)
Q4 2013	$22
2014	(165)
2015	216
2016 – 2022	16
Total	$89

90

The table below reconciles the changes in fair value of our natural gas and oil derivatives during the Current Period. Of the $583 million fair value liability as of September 30, 2013, $150 million related to contracts maturing in the next 12 months and $433 million related to contracts maturing after 12 months. All open derivative instruments as of September 30, 2013 are expected to mature by December 31, 2022.

	2013
	($ in millions)
Fair value of contracts outstanding, as of January 1	$(924)
Change in fair value of contracts	162
Fair value of new contracts when entered into	—
Contracts realized or otherwise settled	179
Fair value of contracts when closed	—
Fair value of contracts outstanding, as of September 30	$(583)

The change in natural gas and oil prices during the Current Period decreased the liability related to our derivative instruments by $162 million. This unrealized gain is recorded in natural gas, oil and NGL sales. We settled contracts that were in a liability position for $179 million. The realized loss is recorded in natural gas, oil and NGL 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 recognized in natural gas, oil and NGL sales as unrealized gains (losses). Realized gains (losses) consist of settled contracts related to the production periods being reported. Unrealized gains (losses) consist of both temporary fluctuations in the mark-to-market values and settled values related to future production periods of derivatives not designated as cash flow hedges. As of September 30, 2013, we did not have any natural gas or oil derivatives that were designated as cash flow hedges.

The components of natural gas, oil and NGL 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,	
	2013	2012	2013	2012
	($ in millions)			
Natural gas, oil and NGL sales	$1,839	$1,464	$5,303	$3,798
Realized gains (losses) on natural gas, oil and NGL derivatives	(62)	77	(96)	388
Unrealized gains (losses) on natural gas, oil and NGL derivatives	(191)	(104)	237	436
Total natural gas, oil and NGL sales	$1,586	$1,437	$5,444	$4,622

Interest Rate Risk

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

	Years of Maturity						
	2013	2014	2015	2016	2017	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$—	$—	$1,661	$500	$2,294	$6,362	$10,817
Average interest rate	— %	— %	7.89 %	3.25 %	4.41 %	6.11 %	5.89 %
Debt – variable rate[(b)]	$—	$—	$—	$285	$2,000	$—	$2,285
Average interest rate	— %	— %	— %	2.93 %	5.75 %	— %	5.40 %

(a) This amount does not include the discount included in debt of $346 million and interest rate derivatives of $14 million.

(b) This amount does not include the discount included in debt of $34 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 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 a portion of our exposure to volatility in interest rates related to our senior notes and credit facilities, we enter into interest rate derivatives. 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. As of September 30, 2013, the following interest rate derivatives were outstanding:

	Notional Amount ($ in millions)	Weighted Average Rate Fixed	Weighted Average Rate Floating[(a)]	Fair Value Hedge	Fair Value Asset (Liability) ($ in millions)
Fixed to Floating:					
Swaps					
Mature 2020 – 2023	$1,450	6.17 %	1 – 3 mL 430 bp	No	$(65)
Floating to Fixed:					
Swaps					
Mature 2014 – 2015	$1,050	2.13 %	1 – 6 mL	No	(23)
					$(88)

(a) Month LIBOR has been abbreviated “mL” and basis points has been abbreviated “bp”.

In addition to the open derivative positions disclosed above, as of September 30, 2013 we had $66 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains (losses) as they are transferred from either our senior note liability or unrealized interest expense gains (losses) over the remaining seven-year term of our related senior notes.

Realized and unrealized 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 Quarter, the Prior Quarter, the Current Period and the Prior Period are presented below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	($ in millions)			
Interest expense on senior notes	$180	$187	$560	$546
Interest expense on credit facilities	8	13	30	51
Interest expense on term loans	29	112	87	173
Realized (gains) losses on interest rate derivatives	(3)	—	(6)	—
Unrealized (gains) losses on interest rate derivatives	—	(2)	57	(4)
Amortization of loan discount, issuance costs and other	21	24	70	67
Capitalized interest	(195)	(298)	(634)	(770)
Total interest expense	$40	$36	$164	$63

Foreign Currency Derivatives

In December 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 cross currency swaps to mitigate our exposure to fluctuations in the euro relative to the dollar over the term of the notes. In May 2011, we purchased and subsequently retired €256 million in aggregate principal amount of these senior notes following a tender offer, and we simultaneously unwound the cross currency swaps for the same principal amount. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €11 million and we pay the counterparties $17 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €344 million and we will pay the counterparties $459 million. The terms of the cross currency swaps were based on the dollar/euro exchange rate on the issuance date of 1.3325 to €1.00. Through the cross currency swaps, we have eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates and therefore the swaps are designated as cash flow hedges. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheet as a liability of $5 million as of September 30, 2013. The euro-denominated debt in long-term debt has been adjusted to $465 million as of September 30, 2013 using an exchange rate of $1.3527 to €1.00.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed in reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC 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. As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake’s disclosure controls and procedures pursuant to 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, 2013.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the period ended September 30, 2013 which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. Legal Proceedings

The Company is involved in a number of litigation and regulatory proceedings. Many of these proceedings are in early stages, and many of them seek an indeterminate amount of damages or penalties. See Litigation and Regulatory Proceedings and Environmental Risk in Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, which information is incorporated herein by reference, for a description of matters arising during the Current Quarter and new developments in previously reported proceedings.

In addition, in 2011, the Office of Oil and Gas of the West Virginia Department of Environmental Protection (WVDEP) issued notices of violation (NOVs) against our wholly owned subsidiary Chesapeake Appalachia, L.L.C. (CALLC) related to a drill site in Marshall County, West Virginia. The NOVs alleged inadequate sediment and erosion control, the failure to prevent the flow of material into a stream of the state and danger to persons from slips. Following remediation by CALLC in accordance with the requirements of the NOVs, the WVDEP issued notices of abatement for one NOV in 2011 and the other seven NOVs in 2012. CALLC agreed to the terms of a consent order issued on September 13, 2013 by the WVDEP, including paying a civil penalty assessment of $275,000, associated with the NOVs.

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 2012 Form 10-K. This information should be considered carefully, together with other information in this report and other reports and materials we file with the 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 quarter ended September 30, 2013:

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, 2013 through July 31, 2013	981,874	$21.10	—	—
August 1, 2013 through August 31, 2013	128,846	$25.15	—	—
September 1, 2013 through September 30, 2013	64,601	$26.41	—	—
Total	1,175,321	$21.84	—	—

(a) Reflects the surrender to the Company of shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plan and deferred compensation plan using Chesapeake common stock that 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. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits and Financial Statement Schedules

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	8/10/2009		
3.1.2	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3.1.3	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008		
3.1.4	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/8/2012		
10.1	Employment Agreement effective August 14, 2013 between Chesapeake Energy Corporation and M. Christopher Doyle.					X	
10.2	Employment Agreement effective August 14, 2013 between Chesapeake Energy Corporation and Mikell					X	

	Jason Piggott.		
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.	X	
31.1	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X	
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	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.		X

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
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	

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 6, 2013	By: /s/ ROBERT D. LAWLER Robert D. Lawler, President and Chief Executive Officer
Date: November 6, 2013	By: /s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

INDEX TO EXHIBITS

		Incorporated by Reference					
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
3/1/2001	Chesapeake's Restated Certificate of Incorporation, as amended.	10-Q	001-13726	3.1.1	8/10/2009		
3/1/2002	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008		
3/1/2003	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008		
3/1/2004	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010		
3/1/2005	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.5	8/9/2010		
3.2	Chesapeake's Amended and Restated Bylaws.	8-K	001-13726	3.2	6/8/2012		
10.1	Employment Agreement effective August 14, 2013 between Chesapeake Energy Corporation and M. Christopher Doyle.					X	
10.2	Employment Agreement effective August 14, 2013 between Chesapeake Energy Corporation and Mikell Jason Piggott.					X	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges					X	

	and Preferred Dividends.		
31.1	Robert D. Lawler, Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X	
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	Robert D. Lawler, 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	