CHESAPEAKE ENERGY CORP
Form 10-Q
November 03, 2016

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, 2016
[ ] 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 October 28, 2016, there were 887,389,891 shares of our $0.01 par value common stock outstanding.

CHESAPEAKE ENERGY CORPORATION
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PART I. FINANCIAL INFORMATION

Item 1. Condensed Consolidated Financial Statements (Unaudited)
CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2016	December 31, 2015
	($ in millions)	
CURRENT ASSETS:		
Cash and cash equivalents ($1 and $1 attributable to our VIE)	$ 4	$ 825
Accounts receivable, net	893	1,129
Short-term derivative assets	—	366
Other current assets	170	160
Total Current Assets	1,067	2,480
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full cost accounting:		
Proved oil and natural gas properties ($488 and $488 attributable to our VIE)	65,977	63,843
Unproved properties	5,198	6,798
Other property and equipment	2,096	2,927
Total Property and Equipment, at Cost	73,271	73,568
Less: accumulated depreciation, depletion and amortization (($457) and ($428) attributable to our VIE)	(62,296)	(59,365)
Property and equipment held for sale, net	76	95
Total Property and Equipment, Net	11,051	14,298
LONG-TERM ASSETS:		
Long-term derivative assets	—	246
Other long-term assets	405	290
TOTAL ASSETS	$ 12,523	$ 17,314

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

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

	September 30, 2016	December 31, 2015
	($ in millions)	
CURRENT LIABILITIES:		
Accounts payable	$ 660	$ 944
Current maturities of long-term debt, net	656	381
Accrued interest	137	101
Short-term derivative liabilities	160	40
Other current liabilities ($2 and $8 attributable to our VIE)	1,993	2,219
Total Current Liabilities	3,606	3,685
LONG-TERM LIABILITIES:		
Long-term debt, net	9,022	10,311
Long-term derivative liabilities	17	60
Asset retirement obligations, net of current portion	403	452
Other long-term liabilities	407	409
Total Long-Term Liabilities	9,849	11,232
CONTINGENCIES AND COMMITMENTS (Note 4)		
EQUITY:		
Chesapeake Stockholders’ Equity:		
Preferred stock, $0.01 par value, 20,000,000 shares authorized: 7,225,713 and 7,251,515 shares outstanding	3,036	3,062
Common stock, $0.01 par value, 1,500,000,000 and 1,000,000,000 shares authorized: 777,020,715 and 664,795,509 shares issued	8	7
Additional paid-in capital	12,923	12,403
Accumulated deficit	(17,028)	(13,202)
Accumulated other comprehensive loss	(101)	(99)
Less: treasury stock, at cost; 1,289,587 and 1,437,724 common shares	(29)	(33)
Total Chesapeake Stockholders’ Equity (Deficit)	(1,191)	2,138
Noncontrolling interests	259	259
Total Equity (Deficit)	(932)	2,397
TOTAL LIABILITIES AND EQUITY	$ 12,523	$ 17,314

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	($ in millions except per share data)			
REVENUES:				
Oil, natural gas and NGL	$1,177	$1,363	$2,610	$4,122
Marketing, gathering and compression	1,099	2,013	3,241	5,993
Total Revenues	2,276	3,376	5,851	10,115
OPERATING EXPENSES:				
Oil, natural gas and NGL production	164	251	552	826
Oil, natural gas and NGL gathering, processing and transportation	473	483	1,436	1,429
Production taxes	17	25	54	87
Marketing, gathering and compression	1,261	1,955	3,410	5,751
General and administrative	63	49	172	174
Restructuring and other termination costs	—	53	3	39
Provision for legal contingencies	8	—	112	359
Oil, natural gas and NGL depreciation, depletion and amortization	255	488	791	1,773
Depreciation and amortization of other assets	25	31	83	100
Impairment of oil and natural gas properties	433	5,416	2,331	15,407
Impairments of fixed assets and other	751	79	795	167
Net (gains) losses on sales of fixed assets	—	(1)	(5)	3
Total Operating Expenses	3,450	8,829	9,734	26,115
LOSS FROM OPERATIONS	(1,174)	(5,453)	(3,883)	(16,000)
OTHER INCOME (EXPENSE):				
Interest expense	(73)	(88)	(197)	(210)
Losses on investments	(1)	(33)	(3)	(57)
Loss on sale of investment	—	—	(10)	—
Gains on purchases or exchanges of debt	87	—	255	—
Other income (expense)	7	(2)	13	3
Total Other Income (Expense)	20	(123)	58	(264)
LOSS BEFORE INCOME TAXES	(1,154)	(5,576)	(3,825)	(16,264)
INCOME TAX BENEFIT:				
Current income taxes	—	—	—	(6)
Deferred income taxes	—	(937)	—	(3,808)
Total Income Tax Benefit	—	(937)	—	(3,814)
NET LOSS	(1,154)	(4,639)	(3,825)	(12,450)
Net income attributable to noncontrolling interests	(1)	(13)	(1)	(50)
NET LOSS ATTRIBUTABLE TO CHESAPEAKE	(1,155)	(4,652)	(3,826)	(12,500)
Preferred stock dividends	(42)	(43)	(127)	(128)
NET LOSS AVAILABLE TO COMMON STOCKHOLDERS	$(1,197)	$(4,695)	$(3,953)	$(12,628)
LOSS PER COMMON SHARE:				
Basic	$(1.54)	$(7.08)	$(5.47)	$(19.07)
Diluted	$(1.54)	$(7.08)	$(5.47)	$(19.07)

CASH DIVIDEND DECLARED PER COMMON SHARE	$—	$—	$—	$0.0875
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in millions):				
Basic	777	663	722	662
Diluted	777	663	722	662

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	($ in millions)			
NET LOSS	$(1,154)	$(4,639)	$(3,825)	$(12,450)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX:				
Unrealized gains (losses) on derivative instruments, net of income tax expense (benefit) of $0, $5, ($1) and $4	(4)	7	(23)	6
Reclassification of losses on settled derivative instruments, net of income tax expense of $0, $2, $3 and $11	7	5	21	18
Other Comprehensive Income (Loss)	3	12	(2)	24
COMPREHENSIVE LOSS	(1,151)	(4,627)	(3,827)	(12,426)
COMPREHENSIVE INCOME ATTRIBUTABLE TO NONCONTROLLING INTERESTS	(1)	(13)	(1)	(50)
COMPREHENSIVE LOSS ATTRIBUTABLE TO CHESAPEAKE	$(1,152)	$(4,640)	$(3,828)	$(12,476)

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

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

	Nine Months Ended September 30, 2016	2015
	($ in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET LOSS	$(3,825)	$(12,450)
ADJUSTMENTS TO RECONCILE NET LOSS TO CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	874	1,873
Deferred income tax expense (benefit)	—	(3,808)
Derivative (gains) losses, net	283	(642)
Cash receipts on derivative settlements, net	487	850
Stock-based compensation	40	61
Impairment of oil and natural gas properties	2,331	15,407
Net (gains) losses on sales of fixed assets	(5)	3
Renegotiation of natural gas gathering contract	(66)	—
Impairments of fixed assets and other	785	159
Losses on investments	3	57
Loss on sale of investment	10	—
Gains on purchases or exchanges of debt	(255)	—
Restructuring and other termination costs	1	39
Provision for legal contingencies	77	359
Other	(92)	24
Changes in assets and liabilities	(598)	(877)
Net Cash Provided By Operating Activities	50	1,055
CASH FLOWS FROM INVESTING ACTIVITIES:		
Drilling and completion costs	(948)	(2,696)
Acquisitions of proved and unproved properties	(583)	(407)
Proceeds from divestitures of proved and unproved properties	988	188
Additions to other property and equipment	(32)	(114)
Proceeds from sales of other property and equipment	70	80
Cash paid for title defects	(69)	—
Additions to investments	—	(1)
Decrease in restricted cash	—	52
Other	(5)	(7)
Net Cash Used In Investing Activities	(579)	(2,905)

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

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

	Nine Months Ended September 30,	
	2016	2015
	($ in millions)	
CASH FLOWS FROM FINANCING ACTIVITIES:		
Cash paid to purchase debt	(1,979)	—
Proceeds from revolving credit facility borrowings	5,097	—
Payments on revolving credit facility borrowings	(4,857)	—
Proceeds from issuance of term loan	1,500	—
Cash paid for common stock dividends	—	(118)
Cash paid for preferred stock dividends	—	(128)
Cash paid to repurchase noncontrolling interest of CHK C-T	—	(143)
Distributions to noncontrolling interest owners	(8)	(78)
Other	(45)	(32)
Net Cash Used In Financing Activities	(292)	(499)
Net decrease in cash and cash equivalents	(821)	(2,349)
Cash and cash equivalents, beginning of period	825	4,108
Cash and cash equivalents, end of period	$4	$1,759

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

	Nine Months Ended September 30,	
	2016	2015
	($ in millions)	
SUPPLEMENTAL CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$209	$134
Income taxes paid, net of refunds received	$(20)	$50
SUPPLEMENTAL DISCLOSURE OF SIGNIFICANT NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in accrued drilling and completion costs	$(22)	$(124)
Change in accrued acquisitions of proved and unproved properties	$(1)	$61
Change in divested proved and unproved properties	$12	$1,046
Debt exchanged for common stock	$471	$—
Repurchase of noncontrolling interest in CHK C-T	$—	$(872)

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

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

	Nine Months Ended September 30,	
	2016	2015
	($ in millions)	
PREFERRED STOCK:		
Balance, beginning of period	$3,062	$3,062
Conversions of 25,802 and 0 shares of preferred stock for common stock	(26)	—
Balance, end of period	3,036	3,062
COMMON STOCK:		
Balance, beginning of period	7	7
Exchange of senior notes and contingent convertible notes	1	—
Balance, end of period	8	7
ADDITIONAL PAID-IN CAPITAL:		
Balance, beginning of period	12,403	12,531
Stock-based compensation	49	52
Exchange of contingent convertible notes for 55,427,782 and 0 shares of common stock	241	—
Exchange of senior notes for 53,923,925 and 0 shares of common stock	229	—
Conversion of preferred stock for 1,021,506 and 0 shares of common stock	26	—
Equity component of convertible notes repurchases	(25)	—
Dividends on common stock	—	(59)
Dividends on preferred stock	—	(128)
Decrease in tax benefit from stock-based compensation	—	(11)
Balance, end of period	12,923	12,385
RETAINED EARNINGS (ACCUMULATED DEFICIT):		
Balance, beginning of period	(13,202)	1,483
Net loss attributable to Chesapeake	(3,826)	(12,500)
Balance, end of period	(17,028)	(11,017)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(99)	(143)
Hedging activity	(2)	24
Balance, end of period	(101)	(119)
TREASURY STOCK – COMMON:		
Balance, beginning of period	(33)	(37)
Purchase of 33,955 and 37,687 shares for company benefit plans	—	(1)
Release of 182,092 and 81,104 shares from company benefit plans	4	2
Balance, end of period	(29)	(36)
TOTAL CHESAPEAKE STOCKHOLDERS' EQUITY (DEFICIT)	(1,191)	4,282
NONCONTROLLING INTERESTS:		
Balance, beginning of period	259	1,302
Net income attributable to noncontrolling interests	1	50
Distributions to noncontrolling interest owners	(1)	(73)
Repurchase of noncontrolling interest of CHK C-T	—	(1,015)
Balance, end of period	259	264

TOTAL EQUITY (DEFICIT)	$(932)	$4,546

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

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation ("Chesapeake" or the "Company") and its subsidiaries were prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP) and include the accounts of our direct and indirect wholly owned subsidiaries and entities in which Chesapeake has a controlling financial interest. Intercompany accounts and balances have been eliminated. These financial statements were prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with U.S. GAAP. This Form 10-Q relates to the three and nine months ended September 30, 2016 (the "Current Quarter" and the “Current Period”, respectively) and the three and nine months ended September 30, 2015 (the "Prior Quarter" and the “Prior Period”, respectively). Chesapeake's annual report on Form 10-K for the year ended December 31, 2015 ("2015 Form 10-K") includes certain definitions and a summary of significant accounting policies that should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the Current Quarter and the Current Period are not necessarily indicative of the results to be expected for the full year.

Risks and Uncertainties

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and natural gas liquids (NGL) we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of cash we have available for capital expenditures and debt service. A substantial or extended decline in oil, natural gas and NGL prices could have a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we may economically produce. Other risks and uncertainties that could affect us in the current commodity price environment include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks and our ability to meet financial ratios and covenants in our financing agreements.

Reclassifications

In April 2015, the Financial Accounting Standards Board (FASB) issued guidance that requires debt issuance costs related to term debt to be presented in the balance sheet as a direct deduction from the associated debt liability. This standard requires retrospective application and is effective for annual reporting periods beginning after December 15, 2015. This change in accounting principle is preferable since it allows debt issuance costs and debt issuance discounts to be presented similarly in the consolidated balance sheets as a reduction to the face amount of our debt balances. A retrospective change to our consolidated balance sheet as of December 31, 2015, as previously presented, is required pursuant to the guidance. The retrospective adjustment to the December 31, 2015 consolidated balance sheet is shown below.

	As Previously Reported	December 31, 2015 Adjustment Effect	As Adjusted
	$ in millions		

Other long-term assets	$333	$ (43)	$290
Long-term debt, net	$10,354	$ (43)	$10,311

Beginning in the fourth quarter of 2015, we began presenting third party gathering, processing and transportation costs as a component of operating expenses in our statement of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. These costs have been reclassified in our condensed consolidated statement of operations for the Prior Quarter and the Prior Period to conform to the presentation used for the Current Quarter and the Current Period. The net effect of this reclassification did not impact our previously reported net loss, stockholders' equity or cash flows; however, previously reported oil, natural gas and NGL sales have increased from the amounts previously reported, and total operating expenses have increased by those same amounts.

2. Earnings Per Share

Basic earnings per share (EPS) is calculated using the weighted average number of common shares outstanding during the period and includes the effect of any participating securities as appropriate. Participating securities consist of unvested restricted stock issued to our employees and non-employee directors that provide dividend rights.

Diluted EPS is calculated assuming the issuance of common shares for all potentially dilutive securities, provided the effect is not antidilutive. 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 EPS. See Note 3 for further discussion of our contingent convertible senior notes.

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, shares of the following securities and associated adjustments to net income, representing dividends on preferred stock and allocated earnings on participating securities, 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, 2016			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	21	58
5.75% cumulative convertible preferred stock (series A)	$	16	42
5.00% cumulative convertible preferred stock (series 2005B)	$	2	6
4.50% cumulative convertible preferred stock	$	3	6
Participating securities	$	—	1
Three Months Ended September 30, 2015			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	21	59
5.75% cumulative convertible preferred stock (series A)	$	16	42
5.00% cumulative convertible preferred stock (series 2005B)	$	3	6
4.50% cumulative convertible preferred stock	$	3	6
Nine Months Ended September 30, 2016			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	63	58
5.75% cumulative convertible preferred stock (series A)	$	48	42
5.00% cumulative convertible preferred stock (series 2005B)	$	7	6
4.50% cumulative convertible preferred stock	$	9	6
Participating securities	$	—	1
Nine Months Ended September 30, 2015			
Common stock equivalent of our preferred stock outstanding:			
5.75% cumulative convertible preferred stock	$	64	59
5.75% cumulative convertible preferred stock (series A)	$	47	42
5.00% cumulative convertible preferred stock (series 2005B)	$	8	6

4.50% cumulative convertible preferred stock	$	9	6
Participating securities	$	—	2

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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, 2016 and December 31, 2015:

	September 30, 2016		December 31, 2015	
	Principal Amount	Carrying Amount	Principal Amount	Carrying Amount
	($ in millions)			
Term loan due 2021	$1,500	$1,500	$—	$—
3.25% senior notes due 2016	—	—	381	381
6.25% euro-denominated senior notes due 2017[(a)]	299	299	329	329
6.5% senior notes due 2017	233	233	453	453
7.25% senior notes due 2018	460	460	538	538
Floating rate senior notes due 2019	504	504	1,104	1,104
6.625% senior notes due 2020	807	807	822	822
6.875% senior notes due 2020	291	291	304	304
6.125% senior notes due 2021	555	555	589	589
5.375% senior notes due 2021	272	272	286	286
4.875% senior notes due 2022	453	453	639	639
8.00% senior secured second lien notes due 2022	2,425	3,459	2,425	3,584
5.75% senior notes due 2023	339	339	384	384
2.75% contingent convertible senior notes due 2035[(b)]	2	2	2	2
2.5% contingent convertible senior notes due 2037[(b)(c)]	130	125	1,110	1,027
2.25% contingent convertible senior notes due 2038[(b)(c)]	207	184	340	290
Revolving credit facility	240	240	—	—
Debt issuance costs	—	(49)	—	(43)
Discount on senior notes	—	(2)	—	(4)
Interest rate derivatives[(d)]	—	6	—	7
Total debt, net	8,717	9,678	9,706	10,692
Less current maturities of long-term debt, net[(e)]	(662)	(656)	(381)	(381)
Total long-term debt, net	$8,055	$9,022	$9,325	$10,311

(a) The principal and carrying amounts shown are based on the exchange rate of $1.1235 to €1.00 and $1.0862 to €1.00 as of September 30, 2016 and December 31, 2015, respectively. See Foreign Currency Derivatives in Note 8 for information on our related foreign currency derivatives.

(b) The repurchase, conversion, contingent interest and redemption provisions of our contingent convertible senior notes are as follows:

Holders' Demand Repurchase Rights. 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.

Optional Conversion by Holders. At the holder’s option, prior to maturity under certain circumstances, the notes are convertible into cash and, if applicable, shares of our common stock using a net share settlement process. One 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. During the specified period in the Current Quarter, the price of our common stock was below the threshold level for each series of the contingent convertible senior notes and, as a result, the holders do not have the option to convert their notes into cash and common stock in the fourth quarter of 2016 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. The notes were not convertible under this provision during the Current Quarter and the Prior Quarter. 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 the principal amount.

Contingent Interest. We will pay contingent interest on the convertible senior notes after they have been outstanding at least ten years during certain periods if the average trading price of the notes exceeds the threshold defined in the indenture.

The holders’ demand repurchase dates, the common stock price conversion threshold amounts (as adjusted to give effect to cash dividends on our common stock) 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	Holders' Demand Repurchase Dates	Common Stock Price Conversion Thresholds	Contingent Interest First Payable (if applicable)
2.75% due 2035	November 15, 2020, 2025, 2030	$ 45.02	May 14, 2016
2.5% due 2037	May 15, 2017, 2022, 2027, 2032	$ 59.44	November 14, 2017
2.25% due 2038	December 15, 2018, 2023, 2028, 2033	$ 100.20	June 14, 2019

Optional Redemption by the Company. We may redeem the contingent 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. In addition, we may redeem our 2.75% Contingent Convertible Senior Notes due 2035 at any time.

(c) The carrying amount associated with the equity component of our contingent convertible senior notes as of September 30, 2016 and December 31, 2015 is net of $28 million and $133 million, respectively. This amount is amortized based on an effective yield method.

(d) See Interest Rate Derivatives in Note 8 for further discussion related to these instruments.

(e) As of September 30, 2016, current maturities of long-term debt, net includes our 6.25% Euro-denominated Senior Notes due 2017, 6.5% Senior Notes due 2017 and our 2.5% Contingent Convertible Senior Notes due 2037 (2037 Notes). As discussed in footnote (b) above, the holders of our 2037 Notes could exercise their individual demand repurchase rights on May 15, 2017, which would require us to repurchase all or a portion of the principal amount of the notes. As of September 30, 2016, there was $5 million associated with the equity component of the 2037 Notes.

Term Loan Facility

In the Current Quarter, we entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion for net proceeds of approximately $1.482 billion. Our obligations under the new facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The loan was made at par without original discount. We used the net proceeds to finance tender offers for our unsecured notes.

The term loan matures in August 2021 and is subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to prepay with net cash proceeds of certain issuances of debt, certain sales and other dispositions of collateral.

The term loan contains covenants limiting our ability to incur additional indebtedness, incur liens, consummate mergers and similar fundamental changes, make restricted payments, sell collateral and use proceeds from such sales, make investments, repay certain subordinate, unsecured or junior lien indebtedness, and enter into transactions with affiliates.

Events of default under the term loan include, among other things, nonpayment of principal, interest or other amounts; violation of covenants; incorrectness of representations and warranties in any material respect; cross-payment default and cross acceleration with respect to other indebtedness with an outstanding principal balance of $125 million or more; bankruptcy; judgments involving liability of $125 million or more that are not paid; and ERISA events. Many events of default are subject to customary notice and cure periods.

Chesapeake Senior Notes and Contingent Convertible Senior Notes

In the Current Quarter, we used the net proceeds from our term loan discussed above to purchase and retire $898 million principal amount of our outstanding senior notes and $708 million principal amount of our outstanding contingent convertible senior notes for an aggregate $1.5 billion pursuant to tender offers. We recognized an aggregate gain of $87 million associated with these debt retirements, which was net of $25 million associated with the equity component of the retired contingent convertible senior notes. In the Current Period, in addition to these tender offers and the repayment upon maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $181 million principal amount of our outstanding senior notes for $151 million and $118 million principal amount of our outstanding contingent convertible senior notes for $63 million. Additionally, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of common stock. In the Current Period, we recorded an aggregate gain of approximately $255 million associated with the tender offers, debt repurchases and exchanges discussed above.

Chesapeake Energy Corporation is a holding company and has no independent assets or operations. Our obligations under our outstanding senior notes and contingent convertible senior notes are fully and unconditionally guaranteed, jointly and severally, by certain of our 100% owned subsidiaries on a senior unsecured basis. Our non-guarantor subsidiaries are minor and, as such, we have not included condensed consolidating financial information.

Revolving Credit Facility

We have a $4.0 billion senior secured revolving credit facility that matures in December 2019. As of September 30, 2016, we had outstanding borrowings of $240 million under the revolving credit facility and had used $709 million of the revolving credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation discussed in Note 4). The terms of the revolving credit facility include covenants limiting, among other things, our ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into transactions with affiliates. We were in compliance with all applicable financial covenants under the agreement as of September 30, 2016.

In the Current Period, we entered into the third amendment to our revolving credit facility. Pursuant to the amendment, our borrowing base was reaffirmed in the amount of $4.0 billion and the next scheduled borrowing base redetermination review was postponed until June 15, 2017, with the consenting lenders agreeing not to exercise their interim redetermination right prior to that date. Our borrowing base may be reduced if we dispose of a certain percentage of the value of the collateral securing the facility. As a result of asset sales discussed in Note 16 and all other sales of collateral since the date of the most recent amendment, as of October 31, 2016, our borrowing base was reduced to $3.8 billion. The amendment also provides temporary financial covenant relief, with the revolving credit facility's existing first lien secured leverage ratio and net debt to capitalization ratio suspended until September 30, 2017 and the interest coverage ratio maintenance covenant reduced as noted below. In addition, we agreed to grant liens and security interests on a majority of our assets, as well as maintain a minimum liquidity amount (defined as cash and cash equivalents and availability under our revolving credit facility) of $500 million until the suspension of the existing maintenance covenants ends.

The amendment reduces the interest coverage ratio from 1.1 to 1.0 to 0.65 to 1.0 through the first quarter of 2017, after which it will increase to 0.70 to 1.0 through the second quarter of 2017, 1.2 to 1.0 through the third quarter of 2017 and 1.25 to 1.0 thereafter. The amendment also includes a collateral value coverage test whereby if the collateral value coverage ratio, tested as of December 31, 2016, falls below 1.1 to 1.0, the $500 million minimum liquidity covenant increases to $750 million, and if the collateral value coverage ratio, tested as of March 31, 2017, falls below 1.25 to 1.0, our borrowing ability will be reduced in order to satisfy such ratio. The amendment also gives us the ability to incur up to $2.5 billion of first lien indebtedness secured on a pari passu basis with the existing obligations under the credit agreement, subject to a position in the collateral proceeds waterfall in favor of the revolving lenders and the other limitations on junior lien debt set forth in the credit agreement. After taking into account the term loan, the amount of additional first lien indebtedness permitted by the revolving credit facility is $1.0 billion.

Fair Value of Debt

We estimate the fair value of our senior notes using quoted market prices (Level 1). The fair value of all other debt, including borrowings under our revolving credit facility, 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, 2016		December 31, 2015	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	($ in millions)			
Short-term debt (Level 1)	$656	$661	$381	$ 366

Long-term debt (Level 1)	$7,299	$6,031	$10,304	$ 3,735
Long-term debt (Level 2)	$1,717	$1,788	$—	$ —

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 or may seek damages and penalties, the amount of which is indeterminate. 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.

2016 Shareholder Litigation. On April 19, 2016, a derivative action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and current and former directors and officers of the Company alleging, among other things, violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act, breach of fiduciary duties, waste of corporate assets, gross mismanagement and violations of Sections 10(b) and Rule 10b-5 of the Exchange Act related to actions allegedly taken by such persons since 2008. The lawsuit seeks certification as a class action, damages, attorneys’ fees and other costs.

Regulatory and Related Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company’s royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

In addition, the Company received a DOJ subpoena and a voluntary document request from the SEC seeking information on our accounting methodology for the acquisition and classification of oil and natural gas properties and related matters. Chesapeake has engaged in discussions with the DOJ and SEC about these matters. On October 4, 2016, a securities class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and certain current directors and officers of the Company alleging, among other things, violations of federal securities laws for purported misstatements in the Company’s SEC filings and other public disclosures regarding the Company’s accounting for the acquisition and classification of oil and natural gas properties. The lawsuit seeks certification as a class action, damages, attorneys’ fees and other costs.

Redemption of 2019 Notes. As previously disclosed in the 2015 Form 10-K, in connection with the litigation related to the Company’s notice issued on March 15, 2013 to redeem all of the 2019 Notes at par (plus accrued interest through the redemption date) pursuant to the special early redemption provision of the supplemental indenture governing the 2019 Notes, the Company filed a notice of appeal on July 27, 2015 of an amended judgment entered on July 17, 2015 by the U.S. District Court for the Southern District of New York awarding the Trustee for the 2019 Notes $380 million plus prejudgment interest in the amount of $59 million. The Company posted a supersedeas bond in the amount of $461 million (reflected as an outstanding letter of credit under the Company’s revolving credit facility) to stay execution of the judgment while appellate proceedings are pending. The Company accrued a loss contingency of $100 million for this matter in 2014 and an additional $339 million in 2015. On September 15, 2016, the United States Court of Appeals for the Second Circuit affirmed the trial court's ruling. We intend to seek a rehearing en banc of the appeal by the U.S. Court of Appeals for the Second Circuit and may file a petition for writ of certiorari with the United States Supreme Court.

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 oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, 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. Plaintiffs have varying royalty provisions in their respective leases, oil and gas law varies from state to state, and royalty owners and producers differ in their interpretation of the legal effect of lease provisions governing royalty calculations. The Company has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages with respect to royalty underpayment in various states, including, but not limited to, Texas, Pennsylvania, Ohio, Oklahoma, Kentucky, Louisiana and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices.

Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order to move a substantial portion of these lawsuits to the 348th District Court of Tarrant County for pre-trial purposes (MDL). These lawsuits, which primarily relate to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. Chesapeake entered into a settlement agreement with MDL plaintiffs representing over 97% of the hydrocarbons at issue by volume and, on July 22, 2016, the plaintiffs who accepted the settlement filed to dismiss such lawsuits. Chesapeake funded the settlement amount of approximately $29 million in cash and signed a $10 million, three-year promissory note in July 2016, which is accrued for as of September 30, 2016. Additional plaintiffs are continuing to accept the settlement on a rolling basis. Chesapeake expects that additional lawsuits filed by plaintiffs not participating in the settlement will continue to be pursued and that new plaintiffs will file other lawsuits making similar allegations.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL. On February 8, 2016, the Office of Attorney General amended the complaint to, among other things, add an additional UTPCPL claim and antitrust claim alleging that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases. In response to Chesapeake's preliminary objections, the Office of Attorney General filed a second amended complaint on May 3, 2016, alleging further violations of the UTPCPL based upon alleged predicate violations of the federal Sherman Act and the Federal Trade Commission Act. Chesapeake removed the case to the United States District Court for the Middle District of Pennsylvania on May 27, 2016. On August 15, 2016, the federal court remanded the case to state court.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company’s divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

We believe losses are reasonably possible in certain of the pending royalty cases for which we have not accrued a loss contingency, but we are currently unable to estimate an amount or range of loss or the impact the actions could have on our future results of operations or cash flows. Uncertainties in pending royalty cases generally include the complex nature of the claims and defenses, the potential size of the class in class actions, the scope and types of the properties and agreements involved, and the applicable production years.

The Company is also defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits have been filed in the United States District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the United States District Court of Kansas, in each case against the Company and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney’s fees, costs and interest, as well as enjoinment from adopting practices or plans which would restrain competition in a similar manner as alleged in the lawsuits.

In April 2016, a class action lawsuit on behalf of holders of the Company’s 6.875% Senior Notes due 2020 (the 2020 Notes) and 6.125% Senior Notes due 2021 (2021 Notes) was filed in the U.S. District Court for the Southern District of New York relating to the Company’s December 2015 debt exchange, whereby the Company privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes. The lawsuit alleges that the Company violated the Trust Indenture Act of 1939 and the implied covenant of good faith and fair dealing by benefiting themselves and a minority of noteholders who are qualified institutional buyers (QIBs). According to the lawsuit, as a result of the Company’s private debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness and reducing the value of the 2020 Notes and the 2022 Notes. The lawsuit seeks damages and attorney’s fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the Second Lien Notes are null and void and that the debt exchange effectively resulted in a default under the indentures for the 2020 Notes and the 2021 Notes. In June 2016, the lawsuit was transferred to the United States District Court for the Western District of Oklahoma, and in October 2016, the Company filed a motion to dismiss for failure to state a claim. A hearing date for the motion has not been set.

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 future 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 Contingencies

The nature of the oil and gas business carries with it certain environmental risks for Chesapeake and its subsidiaries. Chesapeake has implemented various policies, programs, 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 established 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 address 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.

Commitments

Gathering, Processing and Transportation Agreements

We have contractual commitments with midstream service companies and pipeline carriers for future gathering, processing and transportation of oil, natural gas and NGL 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 in our estimates of proved reserves. The aggregate undiscounted commitments under our gathering, processing and transportation agreements, excluding any proportionate share of these costs from working interest and royalty interest owners, credits for third-party volumes or future costs under cost-of-service agreements, are presented below.

	September 30, 2016 ($ in millions)
2016	$ 465
2017	1,872
2018	1,667
2019	1,382
2020	1,052
2021 – 2099	6,590
Total	$ 13,028

In addition, we have entered into long-term agreements for certain natural gas gathering and related services within specified acreage dedication areas in exchange for cost-of-service based fees redetermined annually, or tiered fees based on volumes delivered relative to scheduled volumes. Future gathering fees vary with the applicable agreement.

Drilling Contracts

We have contracts with various drilling contractors to utilize drilling services with terms ranging from one year to three years at market-based pricing. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2016, the aggregate undiscounted minimum future payments under these drilling service commitments were approximately $144 million.

Pressure Pumping Contracts

We have an agreement for pressure pumping services. Throughout the term of the agreement, which expires in June 2017, the services agreement requires us to utilize, at market-based pricing, the lesser of (i) three pressure pumping crews through June 30, 2017 or (ii) 50% of the total number of all pressure pumping crews working for us in all of our operating regions during the respective year. We are also required to utilize the pressure pumping services for a minimum number of fracture stages as set forth in the agreement. We are entitled to terminate the agreement in certain situations, including if the contractor fails to provide the overall quality of service provided by similar service providers. These commitments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2016, the aggregate undiscounted minimum future payments under this agreement were approximately $79 million.

Oil, Natural Gas and NGL Purchase Commitments

We commit to purchase oil, natural gas and NGL from other owners in the properties we operate, including owners associated with our volumetric production payment (VPP) transactions. Production purchases under these arrangements are based on market prices at the time of production, and the purchased oil, natural gas and NGL are resold at market prices. See Volumetric Production Payments in Note 9 for further discussion of our VPP transactions.

Net Acreage Maintenance Commitments

Under the terms of our Utica Shale joint venture agreements with Total S.A., we are required to extend, renew or replace expiring joint leasehold, at our cost, to ensure that the net acreage is maintained in certain designated areas as of a future measurement date.

Other Commitments

As part of our normal course of business, we enter into various agreements providing, or otherwise arranging for, 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 acquisitions and 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 and/or other specified matters. 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 entering into or consummating a particular transaction. For divestitures of oil and natural gas properties, our purchase and sale agreements may require the return of a portion of the proceeds we receive as a result of uncured title defects.

Certain of our oil and natural gas 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 these interests have been created, we have the responsibility to bear the cost of developing and producing the reserves attributable to these interests. See Volumetric Production Payments in Note 9 for further discussion of our VPP transactions.

While executing our strategic priorities, we have incurred certain cash charges, including contract termination charges, financing extinguishment costs and charges for unused natural gas transportation and gathering capacity. As we continue to focus on our strategic priorities, we may take certain actions that reduce financial leverage and complexity, and we may incur additional cash and noncash charges.

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5. Other Liabilities

Other current liabilities as of September 30, 2016 and December 31, 2015 are detailed below.

	September 30, 2016	December 31, 2015
	($ in millions)	
Revenues and royalties due others	$499	$ 500
Accrued drilling and production costs	172	212
Joint interest prepayments received	74	169
Accrued compensation and benefits	198	264
Other accrued taxes	55	37
Bank of New York Mellon legal accrual	440	439
Minimum gathering volume commitment	—	201
Accrual for termination of Barnett gathering agreement	334	—
Other	221	397
Total other current liabilities	$1,993	$ 2,219

Other long-term liabilities as of September 30, 2016 and December 31, 2015 are detailed below.

	September 30, 2016	December 31, 2015
	($ in millions)	
CHK Utica ORRI conveyance obligation[(a)]	$168	$ 190
Financing obligations	—	29
Unrecognized tax benefits	94	64
Other	145	126
Total other long-term liabilities	$407	$ 409

(a) The CHK Utica, L.L.C. investors' right to receive, proportionately, a 3% overriding royalty interest (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 through 2023. The liability represents the obligation to deliver future ORRIs. Approximately $36 million and $21 million of the total $204 million and $211 million obligations are recorded in other current liabilities as of September 30, 2016 and December 31, 2015, respectively.

6. Equity

Common Stock

A summary of the changes in our common shares issued for the Current Period and the Prior Period are detailed below.

	Nine Months Ended September 30,	
	2016	2015
	(in thousands)	
Shares issued as of January 1	664,796	664,944
Exchange of convertible notes	55,428	—
Exchange of senior notes	53,924	—
Conversion of preferred stock	1,021	—
Restricted stock issuances (net of forfeitures and cancellations)	1,852	85
Stock option exercises	—	14
Shares issued as of September 30	777,021	665,043

On May 20, 2016, our shareholders approved an amendment to our certificate of incorporation to increase our authorized common stock from 1,000,000,000 shares to 1,500,000,000 shares, par value $0.01 per share.

Preferred Stock

Outstanding shares of our preferred stock for the Current Period and the Prior Period are detailed below.

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	(in thousands)			
Shares outstanding as of January 1, 2016	1,497	1,100	2,559	2,096
Preferred stock conversions[(a)]	(25)	(1)	—	—
Shares outstanding as of September 30, 2016	1,472	1,099	2,559	2,096
Shares outstanding as of January 1, 2015 and September 30, 2015	1,497	1,100	2,559	2,096

(a) In the Current Period, holders of our 5.75% Cumulative Convertible Preferred Stock converted 24,601 shares into 975,488 shares of common stock. Also in the Current Period, holders of our 5.75% (Series A) Cumulative Convertible Preferred Stock converted 1,201 shares into 46,018 shares of common stock. Subsequent to September 30, 2016, we exchanged additional shares of our outstanding preferred stock for shares of our common stock. See Note 16 for information regarding the exchanges.

Dividends

In January 2016, we announced that we were suspending dividend payments on each series of our outstanding convertible preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or bond indentures. Our preferred stock dividends for the Current Period (paid in arrears) are detailed below.

5.75%	5.75% (A)	4.50%	5.00% (2005B)

	($ in millions)			
Dividends in arrears	$63	$ 48	$ 7	$ 9

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Accumulated Other Comprehensive Income (Loss)

For the Current Period and the Prior Period, changes in accumulated other comprehensive income (loss) for cash flow hedges, net of tax, are detailed below.

	Nine Months Ended September 30,	
	2016	2015
	($ in millions)	
Balance, December 31	$(99)	$(143)
Other comprehensive income before reclassifications	(23)	6
Amounts reclassified from accumulated other comprehensive income	21	18
Net other comprehensive income (loss)	(2)	24
Balance, September 30	$(101)	$(119)

For the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, net losses on cash flow hedges for commodity contracts reclassified from accumulated other comprehensive income (loss), net of tax, to oil, natural gas and NGL revenues in the condensed consolidated statements of operations were $7 million, $5 million, $21 million and $18 million, respectively.

7. Share-Based Compensation

Chesapeake's share-based compensation program consists of restricted stock, stock options and performance share units (PSUs) granted to employees and common stock and restricted stock granted to non-employee directors under our long term incentive plans. The restricted stock and stock options are equity-classified awards and the PSUs are liability-classified awards.

Equity-Classified Awards

Restricted Stock. We grant restricted stock units to employees and non-employee directors. Prior to 2014, we also granted restricted stock awards as equity compensation. We refer to both types of awards as restricted stock. A summary of the changes in unvested restricted stock during the Current Period is presented below.

	Shares of Unvested Restricted Stock (in thousands)	Weighted Average Grant Date Fair Value
Unvested restricted stock as of January 1, 2016	10,455	$ 17.31
Granted	4,533	$ 4.55
Vested	(4,551)	$ 17.32
Forfeited	(999)	$ 13.42
Unvested restricted stock as of September 30, 2016	9,438	$ 11.59

The aggregate intrinsic value of restricted stock that vested during the Current Period was approximately $20 million based on the stock price at the time of vesting.

As of September 30, 2016, there was approximately $68 million of total unrecognized compensation expense related to unvested restricted stock. The expense is expected to be recognized over a weighted average period of approximately 1.59 years.

Stock Options. In the Current Period and the Prior Period, we granted members of senior management stock options that vest ratably over a three-year period. In January 2013, we also granted retention awards of stock options to certain officers that vest one-third on each of the third, fourth and fifth anniversaries of the grant date. Each stock option award has an exercise price equal to the closing price of the Company's common stock on the grant date. Outstanding options expire seven to ten years from the date of grant.

We utilize the Black-Scholes option pricing model to measure the fair value of stock options. The expected life of an option is determined using the simplified method. Volatility assumptions are estimated based on an average of historical volatility of Chesapeake stock over the expected life of an option. The risk-free interest rate is based on the U.S. Treasury rate in effect at the time of the grant over the expected life of the option. The dividend yield is based on an annual dividend yield, taking into account the Company's dividend policy, over the expected life of the option. The Company used the following weighted average assumptions to estimate the grant date fair value of the stock options granted in the Current Period.

Expected option life – years	6.0
Volatility	46.07 %
Risk-free interest rate	1.70 %
Dividend yield	— %

The following table provides information related to stock option activity in the Current Period.

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[a]
	(in thousands)			($ in millions)
Outstanding as of January 1, 2016	5,377	$ 19.37	5.80	$ —
Granted	4,932	$ 3.71		
Exercised	—	$ —		$ —
Expired	(771)	$ 19.46		
Forfeited	(945)	$ 5.66		
Outstanding as of September 30, 2016	8,593	$ 11.88	7.47	$ 10
Exercisable as of September 30, 2016	2,844	$ 19.60	5.78	$ —

(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, 2016, there was $9 million of total unrecognized compensation expense related to stock options. The expense is expected to be recognized over a weighted average period of approximately 1.83 years.

Restricted Stock and Stock Option Compensation. We recognized the following compensation costs related to restricted stock and stock options for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	($ in millions)			
General and administrative expenses	$ 10	$ 9	$ 28	$ 33

Oil and natural gas properties	4	3	13	18
Oil, natural gas and NGL production expenses	4	4	10	14
Marketing, gathering and compression expenses	—	—	1	3
Total	$ 18	$ 16	$ 52	$ 68

Liability-Classified Awards

Performance Share Units. We have granted PSUs to senior management that vest ratably over a three-year term and are settled in cash on the third anniversary of the awards. The ultimate amount earned is based on achievement of performance metrics established by the Compensation Committee of the Board of Directors, which include total shareholder return (TSR) and, for certain of the awards, operational performance goals such as finding and development costs and production levels.

For PSUs granted in 2016, the TSR component can range from 0% to 100% and the operational component can range from 0% to 100%, resulting in a maximum payout of 200%. For PSUs granted in 2015, the TSR component can range from 0% to 100%, and each of the two operational components can range from 0% to 50% resulting in a maximum total payout of 200%. For PSUs granted in 2014, the TSR component can range from 0% to 200%, with no operational components. Compensation expense associated with PSU grants is recognized over the service period based on the graded-vesting method. The value of the PSU awards at the end of each reporting period is dependent upon the Company's estimates of the underlying performance measures. The Company utilized the Monte Carlo simulation for the TSR performance measure and the following assumptions to determine the grant date fair value of the PSUs. The payout percentage for all PSU grants is capped at 100% if the Company's absolute TSR is less than zero.

Volatility	87.15%
Risk-free interest rate	0.80 %
Dividend yield for value of awards	— %

The following table presents a summary of our 2016, 2015 and 2014 PSU awards.

	Units	Grant Date Fair Value	September 30, 2016 Fair Value	Vested Liability
		($ in millions)		
2016 Awards:				
Payable 2019	2,348,893	$ 10	$ 18	$ 8
2015 Awards:				
Payable 2018	629,694	$ 13	$ 3	$ 3
2014 Awards:				
Payable 2017	561,215	$ 16	$ —	$ —

PSU Compensation. We recognized the following compensation costs (credits) related to PSUs for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period.

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	($ in millions)			
General and administrative expenses	$7	$(2)	$10	$(16)

Restructuring and other termination costs	—	(1)	1	(16)
Marketing, gathering and compression	—	—	—	(1)
Oil and natural gas properties	—	—	—	(1)
Total	$7	$(3)	$11	$(34)

8. Derivative and Hedging Activities

Chesapeake uses derivative instruments to secure attractive pricing and margins on its share of expected production, to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility. Chesapeake also uses derivative instruments to mitigate a portion of its exposure to foreign currency exchange rate fluctuations. All of our commodity 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.

Oil, Natural Gas and NGL Derivatives

As of September 30, 2016 and December 31, 2015, our oil, natural gas and NGL 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. In exchange for higher fixed prices on certain of our swap trades, we granted options that allow the counterparty to double the notional amount.
- 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 the excess on sold call options and Chesapeake receives the 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.
- 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 prices, no payments are due from either party.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

The estimated fair values of our oil, natural gas and NGL derivative instrument assets (liabilities) as of September 30, 2016 and December 31, 2015 are provided below.

	September 30, 2016		December 31, 2015	
	Volume	Fair Value ($ in millions)	Volume	Fair Value ($ in millions)
Oil (mmbbl):				
Fixed-price swaps	21.8	$ (49)	13.5	$ 144
Call options	8.7	(2)	19.2	(7)
Total oil	30.5	(51)	32.7	137
Natural gas (tbtu):				
Fixed-price swaps	640	(43)	500	229
Collars	38	1	—	—
Call options	160	(26)	295	(99)
Basis protection swaps	44	1	57	—
Total natural gas	882	(67)	852	130
NGL (mmgal):				
Fixed-price swaps	36	(3)	—	—

Total estimated fair value	$ (121)	$ 267

We have terminated certain commodity derivative contracts that were previously designated as cash flow hedges for which the hedged production is still expected to occur. See further discussion below under Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss).

Interest Rate Derivatives

As of September 30, 2016 and December 31, 2015, there were no interest rate derivatives outstanding.

We have terminated fair value hedges related to certain of our 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 four years, we will recognize $6 million in net gains related to these transactions.

Foreign Currency Derivatives

We are party to cross currency swaps to mitigate our exposure to foreign currency exchange rate fluctuations. In the Current Quarter, in connection with our tender offers, we retired €36 million in aggregate principal amount of our 6.25% Euro-denominated Senior Notes due 2017, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $8 million. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €8 million and we pay the counterparties $13 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €266 million and we will pay the counterparties $355 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. The swaps are designated as cash flow hedges and, because they are entirely effective in having eliminated any potential variability in our expected cash flows related to changes in foreign exchange rates, changes in their fair value do not impact earnings. The fair values of the cross currency swaps are recorded on the condensed consolidated balance sheets as liabilities of $56 million and $52 million as of September 30, 2016 and December 31, 2015, respectively. The euro-denominated debt in long-term debt has been adjusted to $299 million as of September 30, 2016, using an exchange rate of $1.1235 to €1.00.

Supply Contract Derivatives

From time to time and in the normal course of business, our marketing subsidiary enters into supply contracts under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas, thereby creating an embedded derivative requiring bifurcation. In one of these supply contracts, we were committed to supply a minimum of 90 bbtu per day of natural gas through March 2025. In the Current Quarter, we sold the long-term natural gas supply contract to a third party for cash proceeds of $146 million, which is included in marketing, gathering and compression revenues as a realized gain. We reversed the cumulative unrealized gains, resulting in an unrealized loss of $280 million in the Current Quarter and $297 million in the Current Period, respectively.

Effect of Derivative Instruments – Condensed Consolidated Balance Sheets

The following table presents the fair value and location of each classification of derivative instrument included in the condensed consolidated balance sheets as of September 30, 2016 and December 31, 2015 on a gross basis and after same-counterparty netting:

Balance Sheet Classification	Gross Fair Value	Amounts Netted in Condensed Consolidated Balance Sheet	Net Fair Value Presented in Condensed Consolidated Balance Sheet
	($ in millions)		
As of September 30, 2016			
Commodity Contracts:			
Short-term derivative asset	$31	$ (31)	$ —
Short-term derivative liability	(135)	31	(104)
Long-term derivative asset	1	(1)	—
Long-term derivative liability	(18)	1	(17)
Total commodity contracts	(121)	—	(121)
Foreign Currency Contracts:[(a)]			
Short-term derivative liability	(56)	—	(56)
Total foreign currency contracts	(56)	—	(56)
Total derivatives	$(177)	$ —	$ (177)
As of December 31, 2015			
Commodity Contracts:			
Short-term derivative asset	$381	$ (66)	$ 315
Short-term derivative liability	(106)	66	(40)
Long-term derivative liability	(8)	—	(8)
Total commodity contracts	267	—	267
Foreign Currency Contracts:[(a)]			
Long-term derivative liability	(52)	—	(52)
Total foreign currency contracts	(52)	—	(52)
Supply Contracts:			
Short-term derivative asset	51	—	51
Long-term derivative asset	246	—	246
Total supply contracts	297	—	297
Total derivatives	$512	$ —	$ 512

(a) Designated as cash flow hedging instruments.

As of September 30, 2016 and December 31, 2015, we did not have any cash collateral balances for these derivatives.

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Effect of Derivative Instruments – Condensed Consolidated Statements of Operations

The components of oil, natural gas and NGL revenues 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,	
	2016	2015	2016	2015
	($ in millions)			
Oil, natural gas and NGL revenues	$1,048	$1,136	$2,744	$3,782
Gains (losses) on undesignated oil, natural gas and NGL derivatives	136	234	(110)	369
Losses on terminated cash flow hedges	(7)	(7)	(24)	(29)
Total oil, natural gas and NGL revenues	$1,177	$1,363	$2,610	$4,122

The components of marketing, gathering and compression revenues 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,	
	2016	2015	2016	2015
	($ in millions)			
Marketing, gathering and compression revenues	$1,379	$1,943	$3,538	$5,703
Gains (losses) on undesignated supply contract derivatives	(280)	70	(297)	290
Total marketing, gathering and compression revenues	$1,099	$2,013	$3,241	$5,993

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,	
	2016	2015	2016	2015
	($ in millions)			
Interest expense on senior notes	$114	$171	$336	$513
Amortization of loan discount, issuance costs and other	9	14	27	37
Interest expense on revolving credit facility	10	2	27	8
Gains on terminated fair value hedges	(1)	—	(2)	(2)
Gains on undesignated interest rate derivatives	—	—	—	(10)
Capitalized interest	(59)	(99)	(191)	(336)
Total interest expense	$73	$88	$197	$210

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Effect of Derivative Instruments – Accumulated Other Comprehensive Income (Loss)

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

	Three Months Ended September 30,			
	2016		2015	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(163)	$(104)	$(211)	$(131)
Net change in fair value	(4)	(4)	12	7
Losses reclassified to income	7	7	7	5
Balance, end of period	$(160)	$(101)	$(192)	$(119)

	Nine Months Ended September 30,			
	2016		2015	
	Before Tax	After Tax	Before Tax	After Tax
	($ in millions)			
Balance, beginning of period	$(160)	$(99)	$(231)	$(143)
Net change in fair value	(23)	(23)	10	6
Losses reclassified to income	23	21	29	18
Balance, end of period	$(160)	$(101)	$(192)	$(119)

Approximately $92 million of the $101 million of accumulated other comprehensive loss as of September 30, 2016 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. Deferred gain or loss amounts will be recognized in earnings in the month in which the originally forecasted hedged production occurs. As of September 30, 2016, 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 amounts will be transferred by December 31, 2022.

Credit Risk Considerations

Our derivative instruments expose us to our counterparties' credit risk. 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, 2016, our oil, natural gas and NGL and foreign currency derivative instruments were spread among 13 counterparties.

Hedging Arrangements

In 2015, we began entering into bilateral hedging agreements. The counterparties' and our obligations under certain of the bilateral hedging agreements must be secured by cash or letters of credit to the extent that any mark-to-market amounts owed to us or by us exceed defined thresholds. In 2016, certain of our counterparties that are also lenders under our revolving credit facility entered into derivative contracts to be secured by the same collateral that secures the revolving credit facility. This will allow us to reduce any letters of credit posted as security with those counterparties.

Fair Value

The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil, natural gas and NGL forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are compared to the values given by our counterparties for reasonableness. Since oil, natural gas, NGL, 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.

The following table provides information for financial assets (liabilities) measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of September 30, 2016				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 32	$ —	$ 32
Commodity liabilities	—	(123)	(30)	(153)
Foreign currency liabilities	—	(56)	—	(56)
Total derivatives	$ —	$ (147)	$ (30)	$ (177)
As of December 31, 2015				
Derivative Assets (Liabilities):				
Commodity assets	$ —	$ 372	$ 9	$ 381
Commodity liabilities	—	(14)	(100)	(114)
Foreign currency liabilities	—	(52)	—	(52)
Supply contract assets	—	—	297	297
Total derivatives	$ —	$ 306	$ 206	$ 512

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

	Commodity Derivatives	Supply Contracts
	($ in millions)	
Beginning balance as of December 31, 2015	$(91)	$ 297
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	12	(118)
Total purchases, issuances, sales and settlements:		
Settlements	49	(33)
Sales	—	(146)
Ending balance as of September 30, 2016	$(30)	$ —
Beginning balance as of December 31, 2014	$(54)	$ 1
Total gains (losses) (realized/unrealized):		
Included in earnings[(a)]	99	281
Total purchases, issuances, sales and settlements:		
Settlements	(122)	9
Ending balance as of September 30, 2015	$(77)	$ 291

(a)

	Oil, Natural Gas and NGL Sales		Marketing, Gathering and Compression Revenue	
	2016	2015	2016	2015
	($ in millions)			
Total gains (losses) included in earnings for the period	$12	$99	$(118)	$281
Change in unrealized gains (losses) related to assets still held at reporting date	$(1)	$72	$—	$281

Qualitative and Quantitative 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, market volatility and credit risk of counterparties. Changes in these inputs impact the fair value measurement of our derivative contracts. For example, an increase or decrease in the forward prices and volatility of oil and natural gas prices decreases or increases the fair value of oil and natural gas derivatives, and adverse changes to our counterparties' creditworthiness decreases the fair value of our derivatives. The following table presents quantitative information about Level 3 inputs used in the fair value measurement of our commodity derivative contracts at fair value as of September 30, 2016:

Instrument Type	Unobservable Input	Range	Weighted Average	Fair Value September 30, 2016
				($ in millions)
Oil trades[(a)]	Oil price volatility curves	21.09% – 31.73%	29.04%	$ (2)

Natural gas trades[(a)]	Natural gas price volatility curves	21.20% – 59.56%	25.31%	$ (28)

(a) Fair value is based on an estimate derived from option models.

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9. Oil and Natural Gas Property Transactions

Under full cost accounting rules, we accounted for the sales of oil and natural gas properties discussed below as adjustments to capitalized costs, with no recognition of gain or loss as the sales did not involve a significant change in proved reserves or significantly alter the relationship between costs and proved reserves.

In the Current Quarter, we acquired oil and natural gas properties in the Haynesville Shale for approximately $85 million. In the Current Quarter and the Current Period, we sold certain of our noncore oil and natural gas properties for net proceeds of approximately $26 million and $988 million, respectively, after post-closing adjustments. Additional consideration of approximately $106 million was withheld subject to certain title, environmental and other standard contingencies. We expect the majority of the amount subject to the hold back will be received. In conjunction with certain of these sales, we purchased oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions for approximately $259 million. Substantially all of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas.

In the Prior Quarter, CHK Cleveland Tonkawa, L.L.C. (CHK C-T) sold all of its oil and natural gas properties to FourPoint Energy, LLC and immediately used the consideration, plus other cash it had on hand, to repurchase and cancel all of CHK C-T’s outstanding preferred shares. In a related transaction, we sold noncore properties adjacent to the CHK C-T properties to FourPoint Energy, LLC for approximately $90 million.

Volumetric Production Payments

From time to time, we have sold certain of our producing assets located in more mature producing regions through the sale of VPPs. A VPP is a limited-term overriding royalty interest in oil and natural gas 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 non-recourse 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 novated to each of the respective VPP buyers hedges that 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 bear the cost of producing the reserves attributable to these interests, which we include as a component of production expenses and production taxes in our condensed consolidated statements of operations in the periods these 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 our full cost ceiling test 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 the 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 oil and natural gas 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.

As of September 30, 2016, our outstanding VPPs consisted of the following:

				Volume Sold			
VPP #	Date of VPP	Location	Proceeds	Oil	Natural Gas	NGL	Total
			($ in millions)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	May 2011	Mid-Continent	$ 853	1.7	138	4.8	177
1	December 2007	Kentucky and West Virginia	1,100	—	208	—	208
			$ 1,953	1.7	346	4.8	385

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

	Three Months Ended September 30, 2016				Three Months Ended September 30, 2015			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	—	—	—	—	76.0	2.1	253.3	4.0
9	37.6	3.2	85.9	4.0	41.4	3.6	92.9	4.3
8[(b)]	—	—	—	—	—	8.9	—	8.9
4[(a)]	—	—	—	—	10.5	2.0	—	2.0
3[(a)]	—	—	—	—	—	1.6	—	1.6
2[(a)]	—	—	—	—	—	1.0	—	1.0
1	—	3.1	—	3.1	—	3.2	—	3.2
	37.6	6.3	85.9	7.1	127.9	22.4	346.2	25.0

	Nine Months Ended September 30, 2016				Nine Months Ended September 30, 2015			
VPP #	Oil	Natural Gas	NGL	Total	Oil	Natural Gas	NGL	Total
	(mbbl)	(bcf)	(mbbl)	(bcfe)	(mbbl)	(bcf)	(mbbl)	(bcfe)
10[(a)]	108.0	3.0	368.7	5.8	237.0	6.5	798.3	12.7
9	115.5	9.9	262.8	12.2	127.5	10.8	284.8	13.2
8[(b)]	—	—	—	—	—	36.5	—	36.5
4[(a)]	20.0	3.8	—	3.9	32.2	6.1	—	6.2
3[(a)]	—	2.5	—	2.5	—	4.9	—	4.9
2[(a)]	—	1.5	—	1.5	—	3.1	—	3.1
1	—	9.5	—	9.5	—	10.0	—	10.0
	243.5	30.2	631.5	35.4	396.7	77.9	1,083.1	86.6

(a) In connection with certain divestitures in the Current Period, we purchased the remaining oil and natural gas interests previously sold in connection with VPP #10, VPP #4, VPP #3 and VPP #2. A majority of the oil and natural gas interests purchased were subsequently sold to the buyers of the assets.

(b) VPP #8 expired in August 2015.

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The volumes remaining to be delivered on behalf of our VPP buyers as of September 30, 2016 were as follows:

		Volume Remaining as of September 30, 2016			
VPP #	Term Remaining	Oil	Natural Gas	NGL	Total
	(in months)	(mmbbl)	(bcf)	(mmbbl)	(bcfe)
9	53	0.6	49.1	1.3	60.2
1	75	—	68.8	—	68.8
		0.6	117.9	1.3	129.0

10. Variable Interest Entities

Chesapeake Granite Wash Trust (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 and because the royalty interest owners, other than Chesapeake, do not have the ability to exercise substantial liquidation rights. Our ownership in the Trust and our previous obligations under the development agreement 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 operation of the majority of the producing wells and the completed development wells, 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 potentially could 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. As of September 30, 2016 and December 31, 2015, we had $259 million of noncontrolling interests on our condensed consolidated balance sheets attributable to the Trust. Net income attributable to the Trust’s noncontrolling interest is presented in our condensed consolidated statements of operations as $1 million in each of the Current Quarter, the Prior Quarter and the Current Period, and a nominal amount in the Prior Period.

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. In consolidation, as of September 30, 2016, $1 million of cash and cash equivalents, $488 million of proved oil and natural gas properties, $457 million of accumulated depreciation, depletion and amortization and $2 million of other current 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.

11. Impairments

Impairments of Oil and Natural Gas Properties

Our proved oil and natural gas properties are subject to quarterly full cost ceiling tests. 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 (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. Estimated future net revenues for the quarterly ceiling limit are calculated using the average of commodity prices on the first day of the month over the trailing 12-month period. In the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments in the carrying value of our oil and natural gas properties of $433 million, $5.416 billion, $2.331 billion and $15.407 billion, respectively. Cash flow hedges which relate to future periods increased the ceiling test impairment by $154 million and $184 million in the Current Quarter and the Prior Quarter, respectively. During the quarter ended June 30, 2016, we recorded an impairment to the carrying value of our oil and natural gas properties of $1.045 billion, which was understated by approximately $14 million. The amount of the understatement has been included in our Current Quarter impairment.

Impairments of Fixed Assets and Other

We review our long-lived assets, other than oil and natural gas properties, for recoverability whenever events or changes in circumstances indicate that carrying amounts may not be recoverable. We recognize an impairment 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,	
	2016	2015	2016	2015
	($ in millions)			
Barnett Shale exit costs	$616	$ —	$616	$—
Gathering systems	96	—	96	—
Natural gas compressors	32	—	52	21
Buildings and land	7	—	14	—
Other	—	79	17	146
Total impairments of fixed assets and other	$751	$ 79	$795	$167

Barnett Shale Exit Costs. On October 31, 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and simultaneously terminated most of our future commitments associated with this asset. As a result of this transaction, we accrued $334 million of charges in the Current Quarter related to the termination of a natural gas gathering agreement associated with the Barnett Shale assets. Additionally, certain of our other property and equipment, including buildings, surface land, compressors and office equipment, qualified as held for sale as of September 30, 2016. We recognized an impairment charge of $282 million in the Current Quarter related to these assets representing the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell.

Gathering Systems, Natural Gas Compressors, Buildings and Land. In the Current Quarter, we entered into a purchase and sale agreement to sell the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. Additionally, certain of our other property and equipment, including gathering systems, natural gas compressors and buildings and land, qualified as held for sale as of September 30, 2016. We recognized an impairment charge of $134 million in the Current Quarter for these assets for the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell.

Nonrecurring Fair Value Measurements. Fair value measurements for certain of the impairments discussed above were based on recent sales information for comparable assets. As the fair value was estimated using the market approach based on recent prices from orderly sales transactions for comparable assets between market participants, these values were classified as Level 2 in the fair value hierarchy. Other inputs used were not observable in the market; these values were classified as Level 3 in the fair value hierarchy.

12. Income Taxes

A valuation allowance for deferred tax assets, including net operating losses, is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, and we consider the tax consequences in the jurisdiction where the taxable income is generated, to determine whether a valuation allowance is required. The evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred tax liabilities, and tax planning strategies as well as the current and forecasted business economics of our industry.

Based on our estimated operating results for the subsequent quarters, we project being in a net deferred tax asset position as of December 31, 2016. We believe it is more likely than not that these deferred tax assets will not be realized. Management assesses the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of deferred tax assets. A significant piece of objective negative evidence evaluated is the projected cumulative loss we expect to incur over the three-year period ending December 31, 2016. This objective negative evidence limits our ability to consider other subjective positive evidence, such as our projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are increased or if objective negative evidence in the form of cumulative losses is no longer present and additional weight is given to subjective evidence such as future expected growth.

13. Fair Value Measurements

Recurring Fair Value Measurements

Other Current Assets. Assets related to Chesapeake's 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.

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.

Financial Assets (Liabilities). The following table provides fair value measurement information for the above-noted financial assets (liabilities) measured at fair value on a recurring basis as of September 30, 2016 and December 31, 2015:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in millions)		
As of September 30, 2016				
Financial Assets (Liabilities):				
Other current assets	$ 48	$ —	$ —	$ 48
Other current liabilities	(49)	—	—	(49)
Total	$ (1)	$ —	$ —	$ (1)
As of December 31, 2015				
Financial Assets (Liabilities):				
Other current assets	$ 50	$ —	$ —	$ 50
Other current liabilities	(51)	—	—	(51)
Total	$ (1)	$ —	$ —	$ (1)

See Note 3 for information regarding fair value measurement of our debt instruments. See Note 8 for information regarding fair value measurement of our derivatives.

Nonrecurring Fair Value Measurements

See Note 11 regarding nonrecurring fair value measurements.

14. Segment Information

As of September 30, 2016, we have two reportable operating segments, each of which is managed separately because of the nature of its operations. The exploration and production operating segment is responsible for finding and producing oil, natural gas and NGL. The marketing, gathering and compression operating segment is responsible for marketing, gathering and compression of oil, natural gas and NGL.

Management evaluates the performance of our segments based upon income (loss) before income taxes. Revenues from the sale of oil, natural gas and NGL related to Chesapeake's ownership interests by our marketing, gathering and compression operating segment are reflected as revenues within our exploration and production operating segment. These amounts totaled $1.025 billion, $1.046 billion, $2.656 billion and $3.483 billion for the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, respectively.

During the Current Period, we changed the structure of our internal organization to include certain assets in our Exploration and Production reportable segment instead of our Other segment. Accordingly, this change has been reflected through retroactive revision of the segment information as of December 31, 2015, as shown in the tables below.

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The following table presents selected financial information for Chesapeake's operating segments:

	Exploration and Production	Marketing, Gathering and Compression	Other	Intercompany Eliminations	Consolidated Total
	($ in millions)				
Three Months Ended September 30, 2016					
Revenues	$1,177	$ 2,124	$—	$ (1,025)	$ 2,276
Intersegment revenues	—	(1,025)	—	1,025	—
Total revenues	$1,177	$ 1,099	$—	$ —	$ 2,276
Income (Loss) Before Income Taxes	$(710)	$ (211)	$(231)	$ (2)	$ (1,154)
Three Months Ended September 30, 2015					
Revenues	$1,363	$ 3,059	$—	$ (1,046)	$ 3,376
Intersegment revenues	—	(1,046)	—	1,046	—
Total revenues	$1,363	$ 2,013	$—	$ —	$ 3,376
Income (Loss) Before Income Taxes	$(5,625)	$ 70	$(37)	$ 16	$ (5,576)
Nine Months Ended September 30, 2016					
Revenues	$2,610	$ 5,897	$—	$ (2,656)	$ 5,851
Intersegment revenues	—	(2,656)	—	2,656	—
Total revenues	$2,610	$ 3,241	$—	$ —	$ 5,851
Income (Loss) Before Income Taxes	$(3,360)	$ (215)	$(248)	$ (2)	$ (3,825)
Nine Months Ended September 30, 2015					
Revenues	$4,122	$ 9,476	$—	$ (3,483)	$ 10,115
Intersegment revenues	—	(3,483)	—	3,483	—
Total revenues	$4,122	$ 5,993	$—	$ —	$ 10,115
Income (Loss) Before Income Taxes	$(16,759)	$ 208	$(82)	$ 369	$ (16,264)

As of September 30, 2016 Total Assets	$10,674	$ 971	$1,195	$ (317)	$ 12,523
As of December 31, 2015 Total Assets (as previously reported)	$11,776	$ 1,524	$4,325	$ (311)	$ 17,314
As of December 31, 2015 Total Assets (as revised)	$14,610	$ 1,524	$1,491	$ (311)	$ 17,314

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15. Recently Issued Accounting Standards

In May 2014, the FASB issued updated revenue recognition guidance to clarify the principles for recognizing revenue and to develop a common revenue standard for U.S. GAAP and international financial reporting standards. The new standard requires the recognition of revenue to depict the transfer of promised goods to customers in an amount reflecting the consideration the company expects to receive in the exchange. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, with early application not permitted. In July 2015, the FASB approved a one-year deferral of the effective date as well as permission to early adopt the new revenue recognition standard as of the original effective date. In March 2016, the FASB issued an update clarifying the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued an update clarifying the identification of performance obligations and licensing implementations guidance. In May 2016, the FASB issued an update clarifying guidance in a few narrow areas and added some practical expedients to the guidance. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In August 2014, the FASB issued updated guidance that requires management, for each annual and interim reporting period, to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the date that the consolidated financial statements are issued. If management concludes that conditions or events raise substantial doubt about the entity’s ability to continue as a going concern, certain disclosures are required to be made within the footnotes to the consolidated financial statements. The amendments in this update are effective for annual periods ending after December 15, 2016 and interim periods thereafter, with early adoption permitted. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In February 2016, the FASB issued updated lease accounting guidance requiring companies to recognize the assets and liabilities for the rights and obligations created by long-term leases of assets on the balance sheet. The accounting standards update is effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued guidance for improvements to employee share-based payment accounting to simplify the accounting for share-based compensation. The new standard requires all excess tax benefits and reductions from differences between the deduction for tax purposes and the compensation cost recorded for financial reporting purposes be recognized as income tax expense or benefit in the income statement and not recognized as additional paid-in capital. The new standard also requires all excess tax benefits and deficiencies to be classified as operating activity within the statement of cash flows. For public business entities, the amendments are effective for annual periods, including interim periods within those annual periods, beginning after December 15, 2016. Early adoption is permitted in any interim or annual period, with any adjustments reflected as of the beginning of the fiscal year of adoption. We have elected to early adopt the amendments effective January 1, 2016. The cumulative-effect adjustment to retained earnings for all excess tax benefits not previously recognized as of the beginning period is fully offset by a corresponding change in the valuation allowance resulting in no change. The implementation of this guidance did not have a material impact on our consolidated financial statements and related disclosures.

In March 2016, the FASB issued new guidance that will result in fewer put or call options embedded in debt instruments qualifying for separate derivative accounting because companies will not be required to assess whether the contingent event, such as change in control or an IPO, is related to interest rates or credit risks. This standard is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are evaluating the impact of this guidance on our consolidated financial statements and related disclosures.

16. Subsequent Events

On October 5, 2016, we issued in a private placement $1.25 billion principal amount of unsecured 5.5% Convertible Senior Notes due 2026. The notes will be convertible, under certain specified circumstances, into cash, common stock or a combination of cash and common stock, at our election. We are using the net proceeds for general corporate purposes, which may include debt repurchases and the repayment of our revolving credit facility and senior notes with near term maturities as they become due.

Additionally, on October 5, 2016, we completed private exchanges of an aggregate of approximately 110.3 million shares of our common stock for (i) 134,000 shares of 5.00% Cumulative Convertible Preferred Stock (Series 2005B), (ii) 606,271 shares of 5.75% Cumulative Convertible Preferred Stock and (iii) 553,007 shares of 5.75% Cumulative Convertible Preferred Stock (Series A).

In October 2016, we repurchased in the open market approximately $105 million principal amount of our outstanding debt scheduled to mature or that could be put to us in 2017 and 2018 for $106 million.

On October 18, 2016, we signed a letter of intent to restructure our natural gas gathering and service agreement in our Powder River Basin operating area with Williams Partners L.P. and Crestwood Equity Partners L.P. The restructured services are expected to replace the current cost-of-service arrangement and improve economics which support increased development across an expanded area of dedication in the region. Subject to board approvals from all three companies of the definitive agreement, the restructured services are to become effective January 1, 2017, for a 20-year term.

On October 31, 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and received from the buyer aggregate net proceeds of approximately $218 million. We simultaneously terminated most of our future commitments associated with this asset. We sold approximately 212,000 net developed and undeveloped acres and approximately 2,800 operated wells, which produced an average of approximately 59 mboe per day in the Current Quarter, along with other property and equipment. In connection with this disposition, we paid $334 million to terminate a natural gas gathering agreement associated with the Barnett Shale assets. Additionally, we may be required to pay up to an additional $70 million in respect of certain title and environmental contingencies.

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, oil, natural gas and NGL sales, average sales prices received, and other operating income and expenses for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net Production:				
Oil (mmbbl)	8	11	25	32
Natural gas (bcf)	268	263	814	802
NGL (mmbbl)	6	7	19	21
Oil equivalent (mmboe)[a]	59	61	180	187
Oil, Natural Gas and NGL Sales ($ in millions)[b]:				
Oil sales	$342	$469	$952	$1,549
Oil derivatives – realized gains (losses)[c]	18	224	102	641
Oil derivatives – unrealized gains (losses)[c]	23	(100)	(217)	(444)
Total oil sales	383	593	837	1,746
Natural gas sales	622	590	1,545	1,937
Natural gas derivatives – realized gains (losses)[c]	(50)	70	192	341
Natural gas derivatives – unrealized gains (losses)[c]	131	33	(204)	(198)
Total natural gas sales	703	693	1,533	2,080
NGL sales	84	77	247	296
NGL derivatives – realized gains (losses)[c]	(2)	—	(5)	—
NGL derivatives – unrealized gains (losses)[c]	9	—	(2)	—
Total NGL sales	91	77	240	296
Total oil, natural gas and NGL sales	$1,177	$1,363	$2,610	$4,122
Average Sales Price (excluding gains (losses) on derivatives):				
Oil ($ per bbl)	$42.94	$44.60	$38.21	$47.90
Natural gas ($ per mcf)	$2.32	$2.25	$1.90	$2.41
NGL ($ per bbl)	$13.93	$10.90	$12.90	$14.06
Oil equivalent ($ per boe)	$17.86	$18.52	$15.27	$20.21
Average Sales Price (including realized gains (losses) on derivatives):				
Oil ($ per bbl)	$45.24	$66.04	$42.31	$67.73
Natural gas ($ per mcf)	$2.13	$2.51	$2.13	$2.84
NGL ($ per bbl)	$13.70	$10.90	$12.66	$14.06
Oil equivalent ($ per boe)	$17.30	$23.33	$16.88	$25.47
Other Operating Income ($ in millions):				
Marketing, gathering and compression net margin[d][e]	$(162)	$58	$(169)	$242

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Expenses ($ per boe):				
Oil, natural gas and NGL production	$2.80	$4.09	$3.07	$4.42
Oil, natural gas and NGL gathering, processing and transportation	$8.07	$7.88	$7.99	$7.64
Production taxes	$0.29	$0.42	$0.30	$0.47
General and administrative[f]	$1.08	$0.79	$0.96	$0.93
Oil, natural gas and NGL depreciation, depletion and amortization	$4.35	$7.95	$4.40	$9.48
Depreciation and amortization of other assets	$0.42	$0.51	$0.46	$0.53
Interest expense[g]	$1.20	$1.41	$1.06	$1.17
Interest Expense ($ in millions):				
Interest expense	$74	$88	$199	$222
Interest rate derivatives – realized (gains) losses[h]	(3)	(2)	(9)	(4)
Interest rate derivatives – unrealized (gains) losses[h]	2	2	7	(8)
Total interest expense	$73	$88	$197	$210

(a) Oil 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.

(b) Beginning in the 2015 fourth quarter, we reclassified our presentation of third party oil, natural gas and NGL gathering, processing and transportation costs to report the costs as a component of operating expenses in the accompanying statements of operations. Previously, these costs were reflected as deductions to oil, natural gas and NGL sales. The net effect of this reclassification did not impact our previously reported net income, stockholders' equity or cash flows; however, previously reported oil, natural gas and NGL sales and consequently total revenues have increased from the previously reported amounts, and total operating expenses have increased by these same amounts.

(c) Realized gains (losses) include the following items: (i) settlements of undesignated derivatives related to current period production revenues, (ii) prior period settlements for option premiums and for early-terminated derivatives originally scheduled to settle against current period production revenues, and (iii) gains (losses) related to de-designated cash flow hedges originally designated to settle against current period production revenues. Unrealized gains (losses) include the change in fair value of open derivatives scheduled to settle against future period production revenues offset by amounts reclassified as realized gains (losses) during the period.

(d) Includes revenue and operating costs. See Depreciation and Amortization of Other Assets under Results of Operations for details of the depreciation and amortization associated with our marketing, gathering and compression segment.

(e) For the Current Quarter and the Current Period, we recorded unrealized losses of $280 million and $297 million, respectively, on the fair value of our supply contract derivative. For the Prior Quarter and Prior Period, we recorded unrealized gains of $70 million and $290 million, respectively, on the fair value of our supply contract derivative. Additionally, in the Current Quarter, we sold the long-term natural gas supply contract to a third party for cash proceeds of $146 million. See Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for discussion related to this instrument.

(f) Excludes restructuring and other termination costs.

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

(h) Realized (gains) losses include interest rate derivative settlements related to current period interest and the effect of (gains) losses on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item. Unrealized (gains) losses include changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the period.

Overview

We own interests in approximately 31,800 oil and natural gas wells and produced an average of approximately 638 mboe per day in the Current Quarter, net to our interest. We have a large and geographically diverse resource base of onshore U.S. unconventional natural gas and liquids assets. We have leading positions in the liquids-rich resource plays of the Eagle Ford Shale in South Texas; the Utica Shale in Ohio and Pennsylvania; the Anadarko Basin in northwestern Oklahoma and the Texas Panhandle; and the Niobrara Shale in the Powder River Basin in Wyoming. Our natural gas resource plays are the Haynesville/Bossier Shales in northwestern Louisiana and East Texas; and the Marcellus Shale in the northern Appalachian Basin in Pennsylvania. On October 31, 2016, we conveyed our interests in the Barnett Shale in the Fort Worth Basin of north central Texas. We also own oil and natural gas marketing and natural gas gathering and compression businesses.

Our Strategy

Our strategy is focused on creating shareholder value through the development of our significant positions in premier U.S. onshore resource plays. In addition, we will continue to focus our financial strategy on maximizing liquidity and improving margins. We continue to apply financial discipline to all aspects of our business with the goal of increasing financial and operational flexibility. Our capital program is focused on investments that can improve our cash flow generating ability regardless of the commodity price environment. We are utilizing fewer rigs in 2016 than we utilized in 2015; however, to improve cash flow, we are increasing completion crews to capitalize on prior investments and generate revenues from initial production on new wells. In 2016, we have provided additional liquidity and sources of capital, primarily from the suspension of dividend payments on our convertible preferred stock, the amendment to our senior revolving credit facility, our convertible notes offering, our secured term loan facility and sales of assets that did not fit in our strategic priorities. In addition, we are strengthening our balance sheet and improving our liquidity position by continuing to exchange or repurchase, where possible at a discount, certain of our debt and preferred equity instruments.

Our substantial inventory of hydrocarbon resources, including our undeveloped acreage, provides a strong foundation to create future value. We have seen and continue to see increased efficiencies and operational improvements, including increased well productivity from larger completions and lower production declines due to a greater focus on strengthening our base production. We believe that these efficiencies, when combined with our improved liquidity position, reduced debt balances and improved cost structure, provide the opportunity to modestly increase our capital program in 2017. Building on our strong and diverse asset base through increasing production and cash flow and further delineating our emerging new development opportunities, we believe that our dedication to financial discipline, the flexibility of our capital program, and our continued focus on safety and environmental stewardship will provide opportunities to create value for Chesapeake and its stakeholders.

Operating Results

Our Current Quarter production of 59 mmboe consisted of 8 mmbbls of oil (14% on an oil equivalent basis), 268 bcf of natural gas (76% on an oil equivalent basis) and 6 mmbbls of NGL (10% on an oil equivalent basis). Our daily production for the Current Quarter averaged approximately 638 mboe, a decrease of 4% from the Prior Quarter. Compared to the Prior Quarter, average daily oil production decreased by 24%, or approximately 27 mbbls per day; average daily natural gas production increased by 2%, or approximately 56 mmcf per day; and average daily NGL production decreased by 14%, or approximately 10 mbbls per day. Our oil and NGL production decreased primarily as a result of the sale of certain of our Mid-Continent assets in 2016 and 2015 as well as a significant reduction in drilling activity. Adjusted for asset sales, our total daily production increased 2% in the Current Quarter compared to the Prior Quarter. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $88 million to $1.048 billion in the Current Quarter compared to $1.136 billion in the Prior Quarter, primarily due to significant decreases in the volumes of oil sold. See Results of Operations below for additional details.

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Our Current Period production of 180 mmboe consisted of 25 mmbbls of oil (14% on an oil equivalent basis), 814 bcf of natural gas (75% on an oil equivalent basis), and 19 mmbbls of NGL (11% on an oil equivalent basis). Our daily production for the Current Period averaged approximately 656 mboe, a decrease of 4% from the Prior Period. Compared to the Prior Period, average daily oil production decreased by 23% or approximately 27 mbbls per day; average daily natural gas production increased by 1%, or approximately 32 mmcf per day; and average daily NGL production decreased by 9%, or approximately 7 mbbls per day. Our oil and NGL production decreased primarily as a result of the sale of certain of our Mid-Continent assets in 2016 and 2015 as well as a significant reduction in drilling activity. Adjusted for asset sales, our total daily production increased 1% in the Current Period compared to the Prior Period. Our oil, natural gas and NGL revenues (excluding gains or losses on oil and natural gas derivatives) decreased approximately $1.038 billion to $2.744 billion in the Current Period compared to $3.782 billion in the Prior Period, primarily due to significant decreases in the prices received for oil, natural gas and NGL sold in addition to lower oil volumes sold. See Results of Operations below for additional details.

Capital Expenditures

Our drilling and completion capital expenditures during the Current Quarter were approximately $332 million and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $21 million, for a total of approximately $353 million. In the Current Quarter, we operated an average of 11 rigs, a decrease of 7 rigs, or 39%, compared to the Prior Quarter. As a result of lower drilling and completion activity, drilling and completion expenditures decreased approximately $135 million in the Current Quarter compared to the Prior Quarter. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $36 million compared to the Prior Quarter.

Our capitalized interest was approximately $59 million and $99 million in the Current Quarter and the Prior Quarter, respectively. The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. Including capitalized interest, total capital investments were approximately $412 million in the Current Quarter compared to $623 million for the Prior Quarter, a decrease of 34%.

Our drilling and completion capital expenditures during the Current Period were approximately $951 million and capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment were approximately $91 million, for a total of approximately $1.042 billion. In the Current Period, we operated an average of ten rigs, a decrease of 23 rigs, or 70%, compared to the Prior Period. As a result of lower drilling and completion activity, drilling and completion expenditures decreased approximately $1.7 billion in the Current Period compared to the Prior Period. The level of capital expenditures for the acquisition of unproved properties, geological and geophysical costs and other property and equipment decreased approximately $85 million compared to the Prior Period.

Our capitalized interest was approximately $191 million and $336 million in the Current Period and the Prior Period, respectively. The decrease in capitalized interest resulted from a lower average balance of our unproved oil and natural gas properties, the primary asset on which interest is capitalized. Including capitalized interest, total capital investments were approximately $1.233 billion in the Current Period compared to $3.1 billion for the Prior Period, a decrease of 60%.

Based on planned activity levels for the remainder of 2016, we project that 2016 capital expenditures for drilling and completions, leasehold, geological and geophysical and other property and equipment will be $1.65 - $1.75 billion, inclusive of capitalized interest. Additionally, we project that 2017 capital expenditures will be $1.82 - $2.62 billion. The decrease from the $3.6 billion spent in 2015 is primarily driven by reduced activity as a result of lower oil and natural gas prices during 2016. See Liquidity and Capital Resources for additional information on how we plan to fund our capital budget.

Strategic Developments

On October 31, 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and received from the buyer aggregate net proceeds of approximately $218 million. We simultaneously terminated most of our future commitments associated with this asset. We sold approximately 212,000 net developed and undeveloped acres and approximately 2,800 operated wells, which produced an average of approximately 59 mboe per day in the Current Quarter, along with other property and equipment. In connection with this transaction, we paid $334 million to terminate a natural gas gathering agreement associated with the Barnett Shale assets. We also may be required to pay an additional $70 million in respect of certain title and environmental contingencies. Additionally, certain of our other property and equipment, including buildings, surface land, compressors and office equipment, qualified as held for sale as of September 30, 2016. We have recognized an impairment charge of $282 million in the Current Quarter related to these assets representing the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell. By exiting the Barnett Shale, we eliminated approximately $1.9 billion of total future midstream and downstream commitments, leading to an expected increase in our operating income for the remainder of 2016 through 2019 of $200 to $300 million annually. In addition, our exit increased the value of our proved reserves.

In September 2016, we entered into a purchase and sale agreement to sell the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. We agreed to sell approximately 882,000 net acres and approximately 5,600 wells along with related gathering assets, and other property, plant and equipment. In connection with this divestiture, we will be required to purchase one of our remaining VPP transactions. All of the acquired interests will be conveyed in our divestiture discussed above and we will no longer have any future obligations related to this VPP. After the repurchase of this VPP, we expect net cash proceeds to be nominal.

In October 2016, we signed a letter of intent to restructure our natural gas gathering and service agreement in our Powder River Basin operating area with Williams Partners, L.P. (Williams) and Crestwood Equity Partners L.P. The restructured services are expected to replace the current cost-of-service arrangement and improve economics which support increased development across an expanded area of dedication in the region. Subject to board approvals from all three companies of the definitive agreement, the restructured services are to become effective January 1, 2017, for a 20-year term.

In October 2016, we repurchased in the open market approximately $105 million principal amount of our outstanding debt scheduled to mature or that could be put to us in 2017 and 2018 for $106 million.

In October 2016, we issued in a private placement $1.25 billion principal amount of unsecured 5.5% Convertible Senior Notes due 2026. The notes will be convertible, under certain specified circumstances, into cash, common stock or a combination of cash and common stock, at our election. On or after September 15, 2019, we may redeem for cash all or part of the notes at par plus accrued interest if our common stock trades above 130% of the conversion price for a specified period. We are using the net proceeds for general corporate purposes, which may include debt repurchases and the repayment of our revolving credit facility and senior notes with near-term maturities as they become due.

In October 2016, we completed private exchanges of an aggregate of approximately 110.3 million shares of our common stock for (i) 134,000 shares of 5.00% Cumulative Convertible Preferred Stock (Series 2005B), (ii) 606,271 shares of 5.75% Cumulative Convertible Preferred Stock and (iii) 553,007 shares of 5.75% Cumulative Convertible Preferred Stock (Series A). This amount of preferred stock represents approximately $1.2 billion of liquidation value, which was exchanged at a discount of over 40%.

In the Current Quarter, we entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion for net proceeds of approximately $1.482 billion. We used the proceeds from our term loan to purchase and retire $898 million principal amount of our outstanding senior notes and $708 million principal amount of our outstanding contingent convertible senior notes for an aggregate $1.5 billion pursuant to tender offers. We recognized an aggregate gain of $87 million associated with these debt retirements.

In the Current Quarter, we renegotiated our natural gas gathering agreement with Williams in our Mid-Continent operating area in exchange for a $66 million payment. This amount will be amortized to oil, natural gas and NGL gathering, processing and transportation expense over the life of the agreement.

In the Current Quarter, we accelerated the value of a long-term natural gas supply contract for $146 million in cash proceeds.

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In the Current Period, we further amended our revolving credit facility agreement. Pursuant to the amendment, our borrowing base was reaffirmed in the amount of $4.0 billion and our next scheduled borrowing base redetermination date was postponed until June 15, 2017, with the consenting lenders agreeing not to exercise their interim redetermination right prior to that date. The amendment also modifies the credit agreement to provide for, among other things, (i) the suspension or modification of certain financial covenants, and (ii) the granting of liens and security interests on substantially all of our assets, including mortgages encumbering 90% of our proved oil and gas properties that constitute borrowing base properties, all hedge contracts and personal property subject to certain agreed upon carve outs. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I for further discussion of the terms of our revolving credit facility.
In the Current Period, in addition to the tender offers described above and the repayment upon maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $181 million principal amount of our outstanding senior notes for $151 million and $118 million principal amount of our outstanding contingent convertible senior notes for $63 million. Additionally, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of our common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of our common stock. We recorded an aggregate gain of approximately $168 million associated with these debt purchases and exchanges.
In the Current Period, we amended certain of our firm transportation agreements in the Haynesville, Barnett and Eagle Ford operating areas, which will reduce our firm transportation volume commitments and fees. We estimate a benefit of approximately $650 million gross ($415 million net) over the term of the contracts, including $80 million gross ($50 million net) in lower unused demand charges for the underutilized capacity and lower transportation fees in 2016.
In the Current Period, we sold certain of our noncore assets for net proceeds of approximately $988 million after post-closing adjustments. Additional consideration of approximately $106 million was withheld subject to certain title, environmental and other standard contingencies. We expect the majority of the amount subject to the hold back will be received. In conjunction with certain of these sales, we purchased four of our VPP transactions for approximately $259 million. A majority of the acquired interests were part of the asset divestitures discussed above and we no longer have any further commitments or obligations related to these VPPs. The asset divestitures cover various operating areas. We continue to pursue the sale of assets that do not fit in our strategic priorities.
In the Current Period, we suspended dividend payments on our convertible preferred stock to provide additional liquidity in the currently depressed commodity environment.

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Liquidity and Capital Resources

Liquidity Overview

Our ability to grow, make capital expenditures and service our debt depends primarily upon the prices we receive for the oil, natural gas and NGL we sell. Substantial expenditures are required to replace reserves, sustain production and fund our business plans. Historically, oil and natural gas prices have been very volatile, and may be subject to wide fluctuations in the future. The substantial decline in oil, natural gas and NGL prices from 2014 levels has negatively affected the amount of cash we have available for capital expenditures and debt service. A substantial or extended decline in oil, natural gas and NGL prices could have a material impact on our financial position, results of operations, cash flows and on the quantities of reserves that we may economically produce. Other risks and uncertainties that could affect our liquidity include, but are not limited to, counterparty credit risk for our receivables, access to capital markets, regulatory risks and our ability to meet financial ratios and covenants in our financing agreements.

As of September 30, 2016, we had a cash balance of approximately $4 million compared to $825 million as of December 31, 2015, and we had a net working capital deficit of approximately $2.539 billion, compared to a net working capital deficit of approximately $1.205 billion as of December 31, 2015. We made significant progress in the Current Period to reduce near-term debt maturities, including reducing our 2017 debt maturities by $1.230 billion, or 65%, and our 2018 debt maturities by $211 million, or 24%. As of September 30, 2016, we had $3.051 billion of borrowing capacity available under our revolving credit facility, with $240 million of outstanding borrowings and $709 million utilized for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation). 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 our debt obligations, including principal and carrying amounts of our notes. Based on our cash balance, forecasted cash flows from operating activities and availability under our revolving credit facility, we expect to be able to fund our planned capital expenditures budget, meet our debt service requirements and fund our other commitments and obligations for the next 12 months.

In the Current Period, we have taken the following measures to improve liquidity:

- entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion, using the proceeds to retire $898 million principal amount of our outstanding senior notes and $708 million principal amount of our outstanding contingent convertible senior notes;
- exchanged 109.4 million shares of common stock for $577 million principal amount of our outstanding senior notes and contingent convertible senior notes;
- repurchased $299 million principal amount of our outstanding senior notes and contingent convertible notes in the open market;
- further amended our revolving credit agreement to reaffirm our borrowing base, postpone our next scheduled borrowing base redetermination date and modify or suspend certain credit agreement financial covenants;
- mitigated a portion of our downside exposure to commodity prices through derivative contracts, suspended dividend payments on our convertible preferred stock and divested assets to increase our liquidity.

Additionally, during October 2016, we issued $1.25 billion principal amount of unsecured 5.5% Convertible Senior Notes due 2026, exchanged 110.3 million shares of common stock for $1.2 billion liquidation value of our preferred stock, reducing $67 million of annual dividend obligations, and repurchased in the open market approximately $105 million principal amount of our outstanding debt scheduled to mature or that could be put to us in 2017 and 2018 for $106 million.

Even though we have taken measures outlined above to mitigate the liquidity concerns facing us for the next 12 months, there can be no assurance that these measures will satisfy our needs. We may continue to access the capital markets or otherwise incur debt to refinance a portion of our outstanding indebtedness and improve our liquidity.

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As operator of a substantial portion of our oil and natural gas properties under development, we have significant control and flexibility over the development plan and the associated timing, enabling us to reduce at least a portion of our capital spending as needed. Our forecasted 2016 capital expenditures, inclusive of capitalized interest, are $1.65 - $1.75 billion, and our 2017 capital expenditures, inclusive of capitalized interest, are $1.82 - $2.62 billion, both significant reductions from our 2015 capital spending level of $3.6 billion. We currently plan to use cash flow from operations and cash on hand to fund our remaining capital expenditures during 2016 and we expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. In addition, we had liquidity (calculated as cash on hand and availability under our revolving credit facility) of approximately $3.7 billion as of November 1, 2016. Management continues to review operational plans for the remainder of 2016 and beyond, which could result in changes to projected capital expenditures and revenues from sales of oil, natural gas and NGL. We closely monitor 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 revolving credit facility.

Some of our counterparties have requested or required us to post collateral as financial assurance of our performance under certain contractual arrangements, such as gathering, processing, transportation and hedging agreements. As of November 1, 2016, we have received requests and posted approximately $345 million in collateral under such arrangements (excluding the supersedeas bond with respect to the 2019 Notes). We may be requested or required by other counterparties to post additional collateral in an aggregate amount of approximately $670 million, which may be in the form of additional letters of credit, cash or other acceptable collateral. However, we have substantial long-term business relationships with each of these counterparties, and we may be able to mitigate any collateral requests through ongoing business arrangements and by offsetting amounts that the counterparty owes us. Any posting of collateral consisting of cash or letters of credit reduces availability under our revolving credit facility and negatively impacts our liquidity.

In addition, during the next 12 months, we may be required to pay up to $440 million in connection with the judgment against us related to the redemption at par value of our 6.775% Senior Notes due 2019. In connection with our appeal of the decision by the U.S. District Court for the Southern District of New York regarding the redemption, we posted a supersedeas bond in the amount of $461 million in July 2015, which is reflected as an outstanding letter of credit under our revolving credit facility. This contingent payment is fully accrued on our condensed consolidated balance sheet. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part 1 of this report for further discussion of the recent developments in this litigation.

To add more certainty to our future estimated cash flows by mitigating our downside exposure to lower commodity prices, as of November 1, 2016, we have downside price protection, through open swaps, on approximately 67% of our projected remaining 2016 oil production at an average price of $46.84 per bbl. We also have downside price protection, through open swaps and collars, on approximately 79% of our projected remaining 2016 natural gas production at an average price of $2.86 per mcf, of which 7% is hedged under two-way collar arrangements based on an average bought put NYMEX price of $3.00 per mcf. In addition, in exchange for a higher price on certain of our oil and natural gas swaps, we have sold certain call options that allow the counterparty to double the notional amount on existing fixed-price swaps. We also have downside price protection, through open swaps, on approximately 18% of our projected remaining 2016 NGL production at average prices of $0.17 per gallon of ethane and $0.46 per gallon of propane. In addition, for 2017 we have downside price protection on approximately 52% of our projected 2017 oil production at an average price of $49.68 per bbl and we have downside price protection, on approximately 63% of our projected 2017 natural gas production at an average price of $3.07 per mcf, of which 3% is hedged under two-way collar arrangements based on an average bought put NYMEX price of $3.00 per mcf.

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Sources of Funds

The following table presents the sources of our cash and cash equivalents for the Current Period and the Prior Period.

	Nine Months Ended September 30,	
	2016	2015
	($ in millions)	
Cash Provided by Operating Activities	$50	$1,055
Proceeds from revolving credit facility borrowings, net	240	—
Proceeds from issuance of term loan	1,500	—
Divestitures of proved and unproved properties	988	188
Sales of other property and equipment	70	80
Decrease in restricted cash	—	52
Total sources of cash and cash equivalents	$2,848	$1,375

Cash provided by operating activities was $50 million in the Current Period compared to $1.055 billion of cash provided by operating activities in the Prior Period. The decrease is primarily the result of lower realized prices for the oil, natural gas and NGL we sold in addition to decreases in the volumes of oil and NGL sold, partially offset by decreases in certain of our operating expenses. 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, gains or losses on sales of fixed assets, deferred income taxes and mark-to-market changes in our derivative instruments. See further discussion below under Results of Operations.

We currently plan to use cash flow from operations, cash on hand and our revolving credit facility to fund our capital expenditures for the remainder of 2016 and for 2017. We expect to generate additional liquidity with proceeds from future sales of assets that we determine do not fit our strategic priorities. We borrowed $5.097 billion and repaid $4.857 billion under our revolving credit facility in the Current Period and had no borrowings or repayments in the Prior Period.

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,	
	2016	2015
	($ in millions)	
Oil and Natural Gas Expenditures:		
Drilling and completion costs[a]	$946	$2,675
Acquisitions of proved and unproved properties	406	102
Interest capitalized on unproved leasehold	179	326
Total oil and natural gas expenditures	1,531	3,103
Other Uses of Cash and Cash Equivalents:		
Cash paid to repurchase debt	1,979	—
Cash paid for title defects	69	—
Additions to other property and equipment	32	114
Dividends paid	—	246
Distributions to noncontrolling interest owners	8	78
Cash paid to repurchase noncontrolling interest of CHK C-T	—	143
Other	50	40
Total other uses of cash and cash equivalents	2,138	621
Total uses of cash and cash equivalents	$3,669	$3,724

(a) Net of $51 million in drilling and completion carries received from our joint venture partners during the Prior Period.

Our primary use of funds is for drilling and completion costs on our oil and natural gas properties. Our drilling and completion costs decreased in the Current Period compared to the Prior Period primarily as a result of significantly decreased activity. During the Current Period, our average operated rig count was ten rigs compared to an average operated rig count of 33 rigs in the Prior Period. Additionally, we used funds to acquire proved and unproved properties. Our acquisitions of proved and unproved properties increased in the Current Period compared to the Prior Period primarily resulting from purchases of oil and natural gas interests previously sold to third parties in connection with four of our VPP transactions for approximately $259 million.

In the Current Period, we used $1.979 billion of cash to reduce $2.164 billion principal amount of debt. In addition to the repayment at maturity of $259 million principal amount of our 3.25% Senior Notes due 2016, we repurchased in the open market approximately $118 million principal amount of our 2.5% Contingent Convertible Senior Notes due 2037 (2037 Notes) (that could have been put to us in May 2017) for $63 million, $122 million principal amount of our 3.25% Senior Notes due 2016 for $115 million (prior to maturity) and $59 million principal amount of our 6.5% Senior Notes due 2017 for $36 million. Additionally in the Current Period, we used the proceeds from our term loan facility to purchase and retire $898 million principal amount of our senior notes and $708 million principal amount of our contingent convertible senior notes for an aggregate $1.5 billion pursuant to tender offers.

We paid dividends on our preferred stock of $128 million in the Prior Period and we paid dividends on our common stock of $118 million in the Prior Period. We eliminated common stock dividends effective in the 2015 third quarter and suspended preferred stock dividends effective in the 2016 first quarter.

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Term Loan Facility

In the Current Quarter, we entered into a secured five-year term loan facility in aggregate principal amount of $1.5 billion for net proceeds of approximately $1.482 billion. Our obligations under the new facility are unconditionally guaranteed on a joint and several basis by the same subsidiaries that guarantee our revolving credit facility and are secured by first-priority liens on the same collateral securing our revolving credit facility (with a position in the collateral proceeds waterfall junior to the revolving credit facility). The term loan bears interest at a rate of London Interbank Offered Rate (LIBOR) plus 7.50% per annum, subject to a 1.00% LIBOR floor, or the Alternative Base Rate (ABR) plus 6.50% per annum, subject to a 2.00% ABR floor, at our option. The loan was made at par without original discount. We used the net proceeds to finance tender offers for our unsecured notes. The term loan matures in August 2021 and is subject to a make-whole premium prior to the second anniversary of the closing of the term loan, a premium to par of 4.25% from the second anniversary until but excluding the third anniversary, a premium to par of 2.125% from the third anniversary until but excluding the fourth anniversary and at par beginning on the fourth anniversary. The term loan may be subject to mandatory prepayments and offers to prepay with net cash proceeds of certain issuances of debt, certain sales and other dispositions of collateral. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I for further discussion of the term loan facility.

Revolving Credit Facility

We have a $4.0 billion senior secured revolving credit facility that matures in December 2019. As of September 30, 2016, we had $240 million of outstanding borrowings under the revolving credit facility and had used $709 million of the revolving credit facility for various letters of credit (including the $461 million supersedeas bond with respect to the 2019 Notes litigation). See Liquidity Overview above for additional information on our collateral postings. Borrowings under the facility bear interest at a variable rate. We are required to secure our obligations under the facility with liens on certain of our oil and natural gas properties, with the liens to be released upon the satisfaction of specific conditions. The applicable interest rates under the facility fluctuate based on the percentage of the borrowing base used. In the Current Period, we amended our revolving credit facility to provide covenant relief and affirm our $4.0 billion borrowing base. Our borrowing base may be reduced if we dispose of a certain percentage of the value of the collateral securing the facility. As a result of asset sales discussed in Note 16 of the notes to our condensed consolidated financial statements included in Item 1 of Part I and all other sales of collateral since the date of the most recent amendment, as of October 31, 2016, our borrowing base was reduced to $3.8 billion. See Note 3 of the notes to our condensed consolidated financial statements included in Item 1 of Part I for further discussion of the terms of the revolving credit facility and the amendment. As of September 30, 2016, our interest coverage ratio was approximately 2.19 to 1.0. As of September 30, 2016, we were in compliance with all applicable financial covenants under the credit agreement.

Hedging Arrangements

In February 2016, our multi-counterparty secured hedging facility was terminated and all liens on the collateral securing the hedging facility were released. In April 2015, we began using bilateral hedging arrangements. For discussion of our bilateral hedging agreements, see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report.

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Senior Note Obligations

Our senior note obligations consisted of the following as of September 30, 2016:

	September 30, 2016	
	Principal Amount	Carrying Amount
	($ in millions)	
6.25% euro-denominated senior notes due 2017[(a)]	$299	$299
6.5% senior notes due 2017	233	233
7.25% senior notes due 2018	460	460
Floating rate senior notes due 2019	504	504
6.625% senior notes due 2020	807	807
6.875% senior notes due 2020	291	291
6.125% senior notes due 2021	555	555
5.375% senior notes due 2021	272	272
4.875% senior notes due 2022	453	453
8.00% senior secured second lien notes due 2022	2,425	3,459
5.75% senior notes due 2023	339	339
2.75% contingent convertible senior notes due 2035[(b)]	2	2
2.5% contingent convertible senior notes due 2037[(b)(c)]	130	125
2.25% contingent convertible senior notes due 2038[(b)(c)]	207	184
Debt issuance costs	—	(26)
Discount on senior notes	—	(2)
Interest rate derivatives[(d)]	—	6
Total senior notes, net	6,977	7,961
Less current maturities of senior notes, net[(e)]	(662)	(656)
Total long-term senior notes, net	$6,315	$7,305

(a) The principal amount shown is based on the exchange rate of $1.1235 to €1.00 as of September 30, 2016. 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 related foreign currency derivatives.

(b) The holders of our contingent convertible senior notes may require us to repurchase, in cash, all or a portion of their notes at 100% of the principal amount of the notes on any of four dates that are five, ten, fifteen and twenty years before the maturity date. The notes are convertible, at the holder's option, prior to maturity under certain circumstances into cash and, if applicable, shares of our common stock using a net share settlement process. We may redeem our 2.75% Contingent Convertible Senior Notes due 2035 at any time.

(c) The carrying amount associated with the equity component of our contingent convertible senior notes as of September 30, 2016 is net of $28 million.

(d) See Note 8 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.

(e) As of September 30, 2016, current maturities of long-term debt, net includes our 6.25% Euro-denominated Senior Notes due January 2017, 6.5% Senior Notes due 2017 and our 2037 Notes. As discussed in footnote (b) above and in Note 3 of the notes to our condensed consolidated financial statements included in Item I of Part 1 of this report, the holders of our 2037 Notes could exercise their individual demand repurchase rights on May 15, 2017, which would require us to repurchase all or a portion of the principal amount of the notes. As of September 30, 2016, there was $5 million of discount associated with the equity component of the 2037 Notes.

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

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Credit Risk

Derivative instruments that enable us to manage our exposure to oil, natural gas and NGL prices, as well as to interest rate and foreign currency 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, 2016, our oil, natural gas, NGL and interest rate derivative instruments were spread among 13 counterparties. Additionally, the counterparties under our commodity hedging arrangements are required to secure their obligations in excess of defined thresholds.

Our accounts receivable are primarily from purchasers of oil, natural gas and NGL ($686 million as of September 30, 2016) and exploration and production companies that own interests in properties we operate ($145 million as of September 30, 2016). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers and joint working interest owners may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit or parent guarantees for receivables from parties which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated. During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized $1 million, $1 million, $5 million and $3 million, respectively, 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 contractual obligations and off-balance sheet commitments. As of September 30, 2016, these arrangements and transactions included (i) operating lease agreements, (ii) volumetric production payments (VPPs) (to purchase production 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. See Notes 4 and 9 of the notes to our condensed consolidated financial statements included in Item 1 of this report for further discussion of commitments and VPPs, respectively.

Results of Operations – Three Months Ended September 30, 2016 vs. September 30, 2015

General. For the Current Quarter, Chesapeake had a net loss of $1.154 billion, or $1.54 per diluted common share, on total revenues of $2.276 billion. This compares to a net loss of $4.639 billion, or $7.08 per diluted common share, on total revenues of $3.376 billion for the Prior Quarter. The net losses in the Current Quarter were primarily driven by impairments of fixed assets and other and oil and natural gas properties while the net losses in the Prior Quarter were primarily driven by impairments of our oil and natural gas properties. See Impairment of Oil and Natural Gas Properties and Impairments of Fixed Assets and Other below.

Oil, Natural Gas and NGL Sales. During the Current Quarter, oil, natural gas and NGL sales were $1.177 billion compared to $1.363 billion in the Prior Quarter. In the Current Quarter, Chesapeake sold 59 mmboe for $1.048 billion at a weighted average price of $17.86 per boe (excluding the effect of derivatives), compared to 61 mmboe sold in the Prior Quarter for $1.136 billion at a weighted average price of $18.52 per boe (excluding the effect of derivatives). The decrease in the price received per boe in the Current Quarter compared to the Prior Quarter resulted in a $40 million decrease in revenues, and decreased sales volumes resulted in a $48 million decrease in revenues, for a total decrease in revenues of $88 million (excluding the effect of derivatives).

For the Current Quarter, our average price received per barrel of oil (excluding the effect of derivatives) was $42.94, compared to $44.60 in the Prior Quarter. Natural gas prices received per mcf (excluding the effect of derivatives) were $2.32 in the Current Quarter and $2.25 in the Prior Quarter. NGL prices received per barrel (excluding the effect of derivatives) were $13.93 in the Current Quarter and $10.90 in the Prior Quarter.

Gains from our oil and natural gas derivatives resulted in net increases in oil, natural gas and NGL revenues of $129 million and $227 million in the Current Quarter and the Prior Quarter, respectively. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a complete listing of all of our derivative instruments as of September 30, 2016.

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A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our Current Quarter production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in Current Quarter revenues of approximately $8 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Quarter revenues of approximately $27 million and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease Current Quarter revenues of $6 million.

The following tables show production and average sales prices received by our operating divisions for the Current Quarter and the Prior Quarter:

	Three Months Ended September 30, 2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	6.5	43.81	140.3	2.56	2.7	15.10	32.6	56	20.99
Northern[c]	1.5	39.19	127.8	2.06	3.3	12.95	26.1	44	13.96
Total	8.0	42.94	268.1	2.32	6.0	13.93	58.7	100 %	17.86

	Three Months Ended September 30, 2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	%	($/boe)[a]
Southern[b]	8.5	45.28	145.1	2.62	3.7	10.43	36.3	59	22.08
Northern[c]	2.0	41.77	117.8	1.79	3.3	11.43	25.0	41	13.34
Total	10.5	44.60	262.9	2.25	7.0	10.90	61.3	100 %	18.52

(a) Average sales prices exclude gains (losses) on derivatives.

(b) Our Southern Division includes the Eagle Ford and Anadarko Basin liquids plays and the Haynesville/Bossier and Barnett natural gas shale plays. The Eagle Ford Shale accounted for approximately 24% of our estimated proved reserves by volume as of December 31, 2015. Eagle Ford Shale production for the Current Quarter and the Prior Quarter was 9.2 mmboe and 9.9 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara liquids plays and the Marcellus natural gas play. The Utica Shale accounted for approximately 18% of our estimated proved reserves by volume as of December 31, 2015. Utica Shale production for the Current Quarter and the Prior Quarter was 11.7 mmboe and 9.7 mmboe, respectively. The Marcellus Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2015. In both the Current Quarter and the Prior Quarter, Marcellus Shale production was 12.4 mmboe.

Our average daily production of 638 mboe for the Current Quarter consisted of approximately 87 mbbls of oil (14% on an oil equivalent basis), approximately 3 bcf of natural gas (76% on an oil equivalent basis) and approximately 66 mbbls of NGL (10% on an oil equivalent basis). Oil production decreased by 24% year over year primarily as a result of the sale of certain of our Mid-Continent assets in 2016 and 2015 as well as a significant reduction in drilling activity. Natural gas production increased by 2% and NGL production decreased by 14%.

Excluding the impact of derivatives, our percentage of revenues from oil, natural gas and NGL is shown in the following table:

	Three Months Ended September 30,	
	2016	2015
Oil	33%	41%
Natural gas	59%	52%

NGL	8%	7%
Total	100%	100%

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Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. Chesapeake recognized $1.099 billion in marketing, gathering and compression revenues in the Current Quarter, of which $146 million related to cash proceeds from the sale of our long-term natural gas supply contract to a third party offset by the reversal of the cumulative unrealized gains of $280 million, with corresponding expenses of $1.261 billion, for a net loss of $162 million. This compares to revenues of $2.013 billion, of which $70 million related to unrealized gains on the fair value of our supply contract derivative, with corresponding expenses of $1.955 billion, for a net margin before depreciation of $58 million in the Prior Quarter. Revenues and expenses decreased in the Current Quarter compared to the Prior Quarter primarily as a result of lower volumes on certain sales contracts with third parties entered into to help meet certain of our oil pipeline and other commitments.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $164 million in the Current Quarter, compared to $251 million in the Prior Quarter. On a unit-of-production basis, production expenses were $2.80 per boe in the Current Quarter compared to $4.09 per boe in the Prior Quarter. The absolute and per unit decrease in the Current Quarter was primarily the result of a reduction in repair and maintenance expenses as well as operating efficiencies across most of our operating areas. Production expenses in the Current Quarter and the Prior Quarter included approximately $10 million and $25 million, or $0.17 and $0.41 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease and operating efficiencies generally improve. Additionally, in connection with certain divestitures in the Current Period, we purchased the remaining oil and natural gas interests previously sold in connection with four of our VPPs and a majority of the oil and natural gas interests purchased were subsequently sold. In addition, one of our VPPs expired in 2015.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $473 million in the Current Quarter compared to $483 million in the Prior Quarter. On a unit-of-production basis, gathering, processing and transportation expenses were $8.07 per boe in the Current Quarter compared to $7.88 per boe in the Prior Quarter. Certain of our gathering agreements require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Three Months Ended September 30,	
	2016	2015
Oil ($ per bbl)	$3.67	$3.35
Natural gas ($ per mcf)	$1.47	$1.49
NGL ($ per bbl)	$8.13	$8.03

Production Taxes. Production taxes were $17 million in the Current Quarter compared to $25 million in the Prior Quarter. On a unit-of-production basis, production taxes were $0.29 per boe in the Current Quarter compared to $0.42 per boe in the Prior Quarter. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in the Current Quarter was primarily due to lower prices received for oil. Production taxes in both the Current Quarter and the Prior Quarter included approximately $1 million, or $0.02 and $0.01 per boe, respectively, associated with VPP production volumes.

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General and Administrative Expenses. General and administrative expenses were $63 million in the Current Quarter and $49 million in the Prior Quarter, or $1.08 and $0.79 per boe, respectively. The absolute and per unit expense increase in the Current Quarter was primarily due to less overhead billed to our partners resulting from certain divestitures in 2015 and 2016. In addition, in the Current Quarter, we recorded positive fair value adjustments to PSUs granted to executives of the Company, which were primarily the result of an increase in the trading price of our common stock.

Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $38 million of internal costs in the Current Quarter and $43 million in the Prior Quarter, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded an expense of $53 million in the Prior Quarter for restructuring and other termination costs. In the Prior Quarter, we reduced our workforce by approximately 15% as part of an overall plan to reduce costs and better align our workforce with the needs of our business and current oil and natural gas commodity prices. In connection with the reduction, we incurred a total charge of approximately $55 million for one-time termination benefits, all of which were paid in cash in the fourth quarter of 2015. Additionally, the Prior Quarter included negative fair value adjustments to PSUs granted to former executives of the Company, which were primarily the result of a decrease in the trading price of our common stock.

Provision for Legal Contingencies. In the Current Quarter, we recorded $8 million for legal contingencies. The Current Quarter provision consists of accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of royalty claims.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $255 million and $488 million in the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $4.35 and $7.95 in the Current Quarter and the Prior Quarter, respectively. The absolute and per unit decrease in the Current Quarter was the result of a lower amortization base, which is due to the 2015 and 2016 impairments of our oil and natural gas properties.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $25 million in the Current Quarter compared to $31 million in the Prior Quarter. On a unit-of-production basis, depreciation and amortization of other assets was $0.42 per boe in the Current Quarter compared to $0.51 per boe in the Prior Quarter. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. The following table shows depreciation expense by asset class for the Current Quarter and the Prior Quarter and the estimated useful lives of these assets.

	Three Months Ended September 30,		Estimated Useful Life
	2016	2015	
	($ in millions)		(in years)
Buildings and improvements	$ 9	$ 10	10 – 39
Natural gas compressors[(a)]	6	8	3 – 20
Computers and office equipment	5	5	3 – 7
Vehicles	1	2	0 – 7
Natural gas gathering systems and treating plants[(a)]	2	3	20

Other	2	3	2 – 20
Total depreciation and amortization of other assets	$ 25	$ 31	

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

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Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. 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 (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. For the Current Quarter and the Prior Quarter, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments of the carrying value of our oil and natural gas properties of $433 million and $5.416 billion, respectively. Cash flow hedges related to future periods increased the ceiling test impairment by $154 million and $184 million in the Current Quarter and the Prior Quarter, respectively.

As of September 30, 2016, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $3.819 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, gathering, processing, transportation and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of September 30, 2016 were $41.68 per bbl of oil and $2.28 per mcf of natural gas, before price differential adjustments.

Impairments of Fixed Assets and Other. In the Current Quarter and the Prior Quarter, we recognized $751 million and $79 million, respectively, of fixed asset impairment losses and other charges. On October 31, 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and simultaneously terminated most of our future commitments associated with this asset. In connection with this transaction, we accrued $334 million of charges in the Current Quarter related to the termination of a natural gas gathering agreement associated with the Barnett Shale assets. Additionally, certain of our other property and equipment, including buildings, surface land, compressors and office equipment, qualified as held for sale as of September 30, 2016. We have recognized an impairment charge of $282 million in the Current Quarter related to these assets representing the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell. Also in the Current Quarter, we have entered into a purchase and sale agreement to sell the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. Additionally, certain of our other property and equipment, including gathering systems, natural gas compressors and buildings and land, qualified as held for sale as of September 30, 2016. We have recognized an impairment charge of $134 million in the Current Quarter for these assets for the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell. The Prior Quarter amount consisted of a $70 million settlement charge for a net acreage maintenance obligation to Total S.A. in our Barnett Shale joint venture and a $9 million impairment of a note receivable.

Net Gains on Sales of Fixed Assets. We recorded net gains on sales of fixed assets of $1 million in the Prior Quarter. The amount primarily related to the sale of buildings, land and other property and equipment.

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Interest Expense. Interest expense was $73 million in the Current Quarter compared to $88 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2016	2015
	($ in millions)	
Interest expense on senior notes	$114	$171
Amortization of loan discount, issuance costs and other	9	14
Interest expense on revolving credit facility	10	2
Realized gains on interest rate derivatives[a]	(3)	(2)
Unrealized (gains) losses on interest rate derivatives[b]	2	2
Capitalized interest	(59)	(99)
Total interest expense	$73	$88
Average senior notes borrowings	$8,984	$11,798
Average revolving credit facility borrowings	$245	$—

(a) Includes settlements related to the interest accrual for the current period and the effect of (gains) losses on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the current period.

The decrease in capitalized interest resulted from a lower average balance of unproved oil and natural gas properties, the primary asset on which interest is capitalized. The decrease in senior note interest expense is primarily due to $41 million of interest on our second lien notes being accounted for as a reduction in the carrying value of debt instead of interest expense as a result of troubled debt restructuring accounting rules. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.20 per boe in the Current Quarter and $1.41 per boe in the Prior Quarter.

Losses on Investments. Losses on investments of $1 million in the Current Quarter were related to our equity investment in Sundrop Fuels, Inc. Losses on investments of $33 million in the Prior Quarter were primarily related to our equity investments in FTS International, Inc. and Sundrop Fuels, Inc.

Gains on Purchases or Exchanges of Debt. In the Current Quarter, we used the proceeds from our $1.5 billion term loan facility to purchase and retire $898 million principal amount of our senior notes and $708 million principal amount of our contingent convertible senior notes for an aggregate $1.5 billion pursuant to tender offers. We recognized an aggregate gain of $87 million associated with these transactions.

Other Income (Expense). Other income was $7 million in the Current Quarter and consisted of $1 million of interest income and $6 million of miscellaneous income. In the Prior Quarter, we recorded $2 million of other expense that consisted of $2 million of interest income and $4 million of miscellaneous expense.

Income Tax Benefit. Chesapeake recorded an income tax benefit of $937 million in the Prior Quarter. Our effective income tax rate was 0.0% in the Current Quarter and 16.8% in the Prior Quarter. The decrease in the effective income tax rate from the Prior Quarter to the Current Quarter is primarily due to the tax benefit at expected rates being fully offset by a valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. 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 income taxes.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $1 million and $13 million in the Current Quarter and the Prior Quarter, respectively. The Current Quarter amount was attributable to the Chesapeake Granite Wash Trust (the Trust). The Prior Quarter amount was primarily related to dividends paid on preferred stock of our CHK C-T subsidiary. The decrease from the Prior Quarter to the Current Quarter is due to the repurchase of all of the preferred shares of CHK C-T from third-party shareholders in August 2015.

Results of Operations – Nine Months Ended September 30, 2016 vs. September 30, 2015

General. For the Current Period, Chesapeake had a net loss of $3.825 billion, or $5.47 per diluted common share, on total revenues of $5.851 billion. This compares to a net loss of $12.450 billion, or $19.07 per diluted common share, on total revenues of $10.115 billion for the Prior Period. The net losses in the Current Period were primarily driven by impairments of fixed assets and other and oil and natural gas properties while the net losses in the Prior Period were primarily driven by impairments of our oil and natural gas properties. See Impairment of Oil and Natural Gas Properties and Impairments of Fixed Assets and Other below.

Oil, Natural Gas and NGL Sales. During the Current Period, oil, natural gas and NGL sales were $2.610 billion compared to $4.122 billion in the Prior Period. In the Current Period, Chesapeake sold 180 mmboe for $2.744 billion at a weighted average price of $15.27 per boe (excluding the effect of derivatives), compared to 187 mmboe sold in the Prior Period for $3.782 billion at a weighted average price of $20.21 per boe (excluding the effect of derivatives). The decrease in the price received per boe in the Current Period compared to the Prior Period resulted in a $149 million decrease in revenues, and decreased sales volumes resulted in an $889 million decrease in revenues, for a total decrease in revenues of $1.038 billion (excluding the effect of derivatives).

For the Current Period, our average price received per barrel of oil (excluding the effect of derivatives) was $38.21, compared to $47.90 in the Prior Period. Natural gas prices received per mcf (excluding the effect of derivatives) were $1.90 in the Current Period and $2.41 in the Prior Period. NGL prices received per barrel (excluding the effect of derivatives) were $12.90 in the Current Period and $14.06 in the Prior Period.

Gains and losses from our oil and natural gas derivatives resulted in a net decrease in oil, natural gas and NGL revenues of $134 million in the Current Period and a net increase of $340 million in the Prior Period, respectively. See Item 3. Quantitative and Qualitative Disclosures About Market Risk in Part I of this report for a complete listing of all of our derivative instruments as of September 30, 2016.

A change in oil, natural gas and NGL prices has a significant impact on our revenues and cash flows. Assuming our Current Period production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in Current Period revenues of approximately $24 million, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in Current Period revenues of approximately $81 million and an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease Current Period revenues of $19 million.

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The following tables show production and average sales prices received by our operating divisions for the Current Period and the Prior Period:

	Nine Months Ended September 30, 2016								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	(%)	($/boe)[a]
Southern[b]	19.4	39.36	422.5	2.03	8.9	13.30	98.6	55	17.62
Northern[c]	5.5	34.21	391.2	1.75	10.2	12.55	81.1	45	12.40
Total	24.9	38.21	813.7	1.90	19.1	12.90	179.7	100 %	15.27

	Nine Months Ended September 30, 2015								
	Oil		Natural Gas		NGL		Total		
	(mmbbl)	($/bbl)[a]	(bcf)	($/mcf)[a]	(mmbbl)	($/bbl)[a]	(mmboe)	(%)	($/boe)[a]
Southern[b]	26.6	49.35	434.4	2.63	11.6	13.28	110.6	59	23.58
Northern[c]	5.8	41.31	367.7	2.16	9.4	15.02	76.5	41	15.35
Total	32.4	47.90	802.1	2.41	21.0	14.06	187.1	100 %	20.21

(a) Average sales prices exclude gains (losses) on derivatives.

(b) Our Southern Division includes the Eagle Ford and Anadarko Basin liquids plays and the Haynesville/Bossier and Barnett natural gas shale plays. The Eagle Ford Shale accounted for approximately 24% of our estimated proved reserves by volume as of December 31, 2015. Eagle Ford Shale production for the Current Period and the Prior Period was 25.9 mmboe and 29.7 mmboe, respectively.

(c) Our Northern Division includes the Utica and Niobrara liquids plays and the Marcellus natural gas play. The Utica Shale accounted for approximately 18% of our estimated proved reserves by volume as of December 31, 2015. Utica Shale production for the Current Period and the Prior Period was 36.7 mmboe and 30.9 mmboe, respectively. The Marcellus Shale accounted for approximately 17% of our estimated proved reserves by volume as of December 31, 2015. In both the Current Period and the Prior Period, Marcellus Shale production was 37.7 mmboe.

Our average daily production of 656 mboe for the Current Period consisted of approximately 91 mbbls of oil (14% on an oil equivalent basis), approximately 3 bcf of natural gas (75% on an oil equivalent basis) and approximately 70 mbbls of NGL (11% on an oil equivalent basis). Oil production decreased by 23% year over year primarily as a result of the sale of certain of our Mid-Continent assets in 2016 and 2015 as well as a significant reduction in drilling activity. Natural gas production increased by 1% and NGL production decreased by 9%.

Excluding the impact of derivatives, our percentage of revenues from oil, natural gas and NGL is shown in the following table:

	Nine Months Ended September 30,	
	2016	2015
Oil	35%	41%
Natural gas	56%	51%
NGL	9%	8%
Total	100%	100%

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Marketing, Gathering and Compression Revenues and Expenses. Marketing, gathering and compression revenues consist of third-party revenues as well as fair value adjustments on our supply contract derivatives (see Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for additional information on our supply contract derivatives). Expenses related to our marketing, gathering and compression operations consist of third-party expenses and exclude depreciation and amortization, general and administrative expenses, impairments of fixed assets and other, net gains or losses on sales of fixed assets and interest expense. See Depreciation and Amortization of Other Assets below for the depreciation and amortization recorded on our marketing, gathering and compression assets. We recognized $3.241 billion in marketing, gathering and compression revenues in the Current Period, of which $146 million related to cash proceeds from the sale of our long-term natural gas supply contract to a third party offset by the reversal of cumulative unrealized gains of $297 million, with corresponding expenses of $3.410 billion, for a net loss of $169 million. This compares to revenues of $5.993 billion, of which $290 million related to unrealized gains on the fair value of our supply contract derivative, with corresponding expenses of $5.751 billion, for a net margin of $242 million in the Prior Period. Revenues and expenses decreased in the Current Period compared to the Prior Period primarily as a result of lower oil, natural gas and NGL prices paid and received in our marketing operations.

Oil, Natural Gas and NGL Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $552 million in the Current Period, compared to $826 million in the Prior Period. On a unit-of-production basis, production expenses were $3.07 per boe in the Current Period compared to $4.42 per boe in the Prior Period. The absolute and per unit decrease in the Current Period was primarily the result of a reduction in repair and maintenance expenses as well as operating efficiencies across most of our operating areas. Production expenses in the Current Period and the Prior Period included approximately $38 million and $89 million, or $0.21 and $0.47 per boe, respectively, associated with VPP production volumes. We anticipate a continued decrease in production expenses associated with VPP production volumes as the contractually scheduled volumes under our VPP agreements decrease and operating efficiencies generally improve. Additionally, in connection with certain divestitures in the Current Period we purchased the remaining oil and natural gas interests previously sold in connection with four of our VPPs and a majority of the oil and natural gas interests repurchased were subsequently sold. In addition, one of our VPPs expired in 2015.

Oil, Natural Gas, and NGL Gathering, Processing and Transportation Expenses. Oil, natural gas and NGL gathering, processing and transportation expenses were $1.436 billion in the Current Period compared to $1.429 billion in the Prior Period. On a unit-of-production basis, gathering, processing and transportation expenses were $7.99 per boe in the Current Period compared to $7.64 per boe in the Prior Period. Certain of our gathering agreements require us to pay the service provider a fee for any production shortfall below certain annual minimum gathering volume commitments. A summary of oil, natural gas and NGL gathering, processing and transportation expenses by product is shown below.

	Nine Months Ended September 30,	
	2016	2015
Oil ($ per bbl)	$3.53	$3.33
Natural gas ($ per mcf)	$1.47	$1.45
NGL ($ per bbl)	$7.77	$7.34

Production Taxes. Production taxes were $54 million in the Current Period compared to $87 million in the Prior Period. On a unit-of-production basis, production taxes were $0.30 per boe in the Current Period compared to $0.47 per boe in the Prior Period. In general, production taxes are calculated using value-based formulas that produce lower per unit costs when oil, natural gas and NGL prices are lower. The absolute and per unit decrease in production taxes in the Current Period was primarily due to lower prices received for oil, natural gas and NGL. Production taxes in the

Current Period and the Prior Period included approximately $3 million and $4 million, respectively, or $0.02 per boe, associated with VPP production volumes.

General and Administrative Expenses. General and administrative expenses were $172 million in the Current Period and $174 million in the Prior Period, or $0.96 and $0.93 per boe, respectively. The expense decrease in the Current Period was primarily due to reduced overhead as a result of our workforce reduction in the 2015 third quarter and our continuing efforts to reduce other administrative expenses. The reduction was offset by less overhead billed to our partners resulting from certain divestitures in 2015 and 2016. In addition, in the Current Period, we recorded positive fair value adjustments to PSUs granted to executives of the Company, which were primarily the result of an increase in the trading price of our common stock.

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Chesapeake follows the full cost method of accounting under which all costs associated with oil and natural gas property acquisition, drilling and completion activities are capitalized. We capitalize internal costs that can be directly identified with the acquisition of leasehold, as well as drilling and completion activities, and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $110 million and $156 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our leasehold acquisition and drilling and completion efforts.

Restructuring and Other Termination Costs. We recorded $3 million and $39 million in the Current Period and the Prior Period, respectively, for restructuring and other termination costs. The Current Period amount was primarily related to the reduction in workforce in connection with the restructuring of our compressor manufacturing subsidiary. In the Prior Period, we reduced our workforce by approximately 15% as part of an overall plan to reduce costs and better align our workforce with the needs of our business and current oil and natural gas commodity prices. In connection with the reduction, we incurred a total charge of approximately $55 million for one-time termination benefits, all of which were paid in cash in the fourth quarter of 2015. Additionally, the Prior Quarter included negative fair value adjustments to PSUs granted to former executives of the Company, which were primarily the result of a decrease in the trading price of our common stock.

Provision for Legal Contingencies. In the Current Period and the Prior Period, we recorded $112 million and $359 million, respectively, for legal contingencies. The Current Period provision consists of accruals for loss contingencies primarily related to royalty claims. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for further discussion of royalty claims. The Prior Period amount includes $25 million related to the resolution in April 2015 of litigation we were defending against the state of Michigan and $339 million related to litigation involving our early redemption of our 2019 notes, partially offset by $5 million related to certain royalty claimants that opted out of a settlement agreement.

Oil, Natural Gas and NGL Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of oil, natural gas and NGL properties was $791 million and $1.773 billion in the Current Period and the Prior Period, respectively. The average DD&A rate per boe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $4.40 and $9.48 in the Current Period and the Prior Period, respectively. The absolute and per unit decrease in the Current Period was the result of a lower amortization base, which is due to the 2015 and 2016 impairments of our oil and natural gas properties.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $83 million in the Current Period compared to $100 million in the Prior Period. On a unit-of-production basis, depreciation and amortization of other assets was $0.46 per boe in the Current Period compared to $0.53 per boe in the Prior Period. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. The following table shows depreciation expense by asset class for the Current Period and the Prior Period and the estimated useful lives of these assets.

	Nine Months Ended September 30,		Estimated Useful Life
	2016	2015	
	($ in millions)		(in years)
Buildings and improvements	$29	$29	10 – 39
Natural gas compressors[(a)]	20	29	3 – 20
Computers and office equipment	15	18	3 – 7
Vehicles	2	8	0 – 7
Natural gas gathering systems and treating plants[(a)]	7	8	20
Other	10	8	2 – 20

Total depreciation and amortization of other assets	$83	$100

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

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Impairment of Oil and Natural Gas Properties. Our oil and natural gas properties are subject to quarterly full cost ceiling tests. 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 (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. For the Current Period and the Prior Period, capitalized costs of oil and natural gas properties exceeded the ceiling, resulting in impairments of the carrying value of our oil and natural gas properties of $2.331 billion and $15.407 billion, respectively.

As of September 30, 2016, the present value of estimated future net revenue of our proved reserves, discounted at an annual rate of 10%, was $3.819 billion. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, gathering, processing, transportation and future development costs, using prices and costs under existing economic conditions as of that date. The prices used in the present value calculation as of September 30, 2016 were $41.68 per bbl of oil and $2.28 per mcf of natural gas, before price differential adjustments.

Impairments of Fixed Assets and Other. In the Current Period and the Prior Period, we recognized $795 million and $167 million, respectively, of fixed asset impairment losses and other charges. On October 31, 2016, we conveyed our interests in the Barnett Shale operating area located in north central Texas and simultaneously terminated most of our future commitments associated with this asset. In connection with this transaction, we accrued $334 million of charges in the Current Period related to the termination of a natural gas gathering agreement associated with the Barnett Shale assets. Certain of our other property and equipment, including buildings, surface land, compressors and office equipment, qualified as held for sale as of September 30, 2016. We have recognized an impairment charge of $282 million in the Current Period related to these assets representing the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell. Also in the Current Period, we have entered into a purchase and sale agreement to sell the majority of our upstream and midstream assets in the Devonian Shale located in West Virginia and Kentucky. Additionally, certain of our other property and equipment, including gathering systems, natural gas compressors and buildings and land, qualified as held for sale as of September 30, 2016. We have recognized an impairment charge of $134 million in the Current Period for these assets for the difference between the carrying amount and the fair value of the assets, less the anticipated costs to sell. The Prior Period amount consisted of a $70 million settlement charge for a net acreage maintenance obligation to Total S.A. in our Barnett Shale joint venture, a $47 million loss contingency related to contract disputes, a $21 million impairment related to the sale of third-party rental compressors, a $22 million impairment of a note receivable and $7 million of charges incurred for terminating drilling contracts as a result of the decline in oil and natural gas prices.

Net (Gains) Losses on Sales of Fixed Assets. In the Current Period, net gains on sales of fixed assets were $5 million compared to net losses of $3 million in the Prior Period. The Current Period and the Prior Period amounts primarily related to the sale of gathering systems, buildings, land and other property and equipment.

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Interest Expense. Interest expense was $197 million in the Current Period compared to $210 million in the Prior Period as follows:

	Nine Months Ended September 30,	
	2016	2015
	($ in millions)	
Interest expense on senior notes	$336	$513
Amortization of loan discount, issuance costs and other	27	37
Interest expense on revolving credit facility	27	8
Realized gains on interest rate derivatives[(a)]	(9)	(4)
Unrealized (gains) losses on interest rate derivatives[(b)]	7	(8)
Capitalized interest	(191)	(336)
Total interest expense	$197	$210
Average senior notes borrowings	$9,158	$11,798
Average credit facility borrowings	$257	$—

(a) Includes settlements related to the interest accrual for the current period and the effect of (gains) losses on early-terminated trades. Settlements of early-terminated trades are reflected in realized (gains) losses over the original life of the hedged item.

(b) Includes changes in the fair value of open interest rate derivatives offset by amounts reclassified to realized (gains) losses during the current period.

The decrease in capitalized interest resulted from a lower average balance of unproved oil and natural gas properties, the primary asset on which interest is capitalized. The decrease in senior note interest expense is primarily due to $124 million of interest on our second lien notes being accounted for as a reduction in the carrying value of debt instead of interest expense as a result of troubled debt restructuring accounting rules. Interest expense, excluding unrealized gains or losses on interest rate derivatives and net of amounts capitalized, was $1.06 per boe in the Current Period and $1.17 per boe in the Prior Period.

Losses on Investments. Losses on investments of $3 million in the Current Period were primarily related to our equity investment in Sundrop Fuels, Inc. Losses on investments of $57 million in the Prior Period were primarily related to our equity investments in FTS International, Inc. and Sundrop Fuels, Inc.

Loss on Sale of Investment. In the Current Period, we sold certain of our mineral interests and assigned our partnership interest in Mineral Acquisition Company I, L.P. to KKR Royalty Aggregator LLC. As a result of the transaction, we wrote off our equity investment and recognized a $10 million loss.

Gains on Purchases or Exchanges of Debt. In the Current Period, we used the proceeds from our term loan facility discussed above to purchase and retire $898 million principal amount of our senior notes and $708 million principal amount of our contingent convertible senior notes for an aggregate $1.5 billion pursuant to tender offers, resulting in a gain of $87 million. Also, in the Current Period, we repurchased in the open market approximately $181 million principal amount of our senior notes for $151 million and $118 million principal amount of our contingent convertible senior notes for $63 million. Additionally, in the Current Period, we privately negotiated exchanges of approximately $290 million principal amount of our outstanding senior notes for 53,923,925 shares of our common stock and $287 million principal amount of our outstanding contingent convertible senior notes for 55,427,782 shares of our common stock, resulting in a gain of $168 million.

Other Income. Other income was $13 million in the Current Period and consisted of $2 million of interest income and $11 million of miscellaneous income. In the Prior Period, other income was $3 million and consisted of $5 million of interest income and $2 million of miscellaneous expense.

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Income Tax Benefit. Chesapeake recorded an income tax benefit of $3.814 billion in the Prior Period. Our effective income tax rate was 0.0% in the Current Period and 23.5% in the Prior Period. The decrease in the effective income tax rate from the Prior Period to the Current Period is primarily due to the tax benefit at expected rates being fully offset by a valuation allowance. Further, our effective tax rate can fluctuate as a result of the impact of state income taxes and permanent differences. 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 income tax expenses.

Net Income Attributable to Noncontrolling Interests. Chesapeake recorded net income attributable to noncontrolling interests of $1 million and $50 million in the Current Period and the Prior Period, respectively. The Current Period amount was attributable to the Trust. The Prior Period amount was primarily related to dividends paid on preferred stock of our CHK C-T subsidiary. The decrease from the Prior Period to the Current Period is due to the repurchase of all of the preferred shares of CHK C-T from third-party shareholders in August 2015.

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 oil, natural gas and NGL production and future expenses, estimated operating costs, assumptions regarding future oil, natural gas and NGL prices, planned drilling activity, estimates of future drilling and completion and other capital expenditures (including the use of joint venture drilling carries), potential future write-downs of our oil and natural gas assets, anticipated sales, and the adequacy of our provisions for legal contingencies, as well as statements concerning anticipated cash flow and liquidity, ability to comply with financial maintenance covenants and meet contractual cash commitments to third parties, debt repurchases, operating and capital efficiencies, business strategy, and other plans and objectives for future operations. Disclosures concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in 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 annual report on Form 10-K for the year ended December 31, 2015 (2015 Form 10-K) and include:

- the volatility of oil, natural gas and NGL prices;
- the limitations our level of indebtedness may have on our financial flexibility;
- our inability to access the capital markets on favorable terms;
- the availability of cash flows from operations and other funds to finance reserve replacement costs or satisfy our debt obligations;
- a further downgrade in our credit rating requiring us to post more collateral under certain commercial arrangements;
- write-downs of our oil and natural gas asset carrying values due to low commodity prices;
- our ability to replace reserves and sustain production;
- uncertainties inherent in estimating quantities of oil, natural gas 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;
- commodity derivative activities resulting in lower prices realized on oil, natural gas and NGL sales;
- the need to secure derivative liabilities and the inability of counterparties to satisfy their obligations;
- adverse developments or losses from pending or future litigation and regulatory proceedings, including royalty claims;
- charges incurred in response to market conditions and in connection with our ongoing actions to reduce financial leverage and complexity;
- drilling and operating risks and resulting liabilities;

- effects of environmental protection laws and regulation on our business;
- legislative and regulatory initiatives further regulating hydraulic fracturing;
- our need to secure adequate supplies of water for our drilling operations and to dispose of or recycle the water used;
- impacts of potential legislative and regulatory actions addressing climate change;
- federal and state tax proposals affecting our industry;
- potential OTC derivatives regulation limiting our ability to hedge against commodity price fluctuations;
- competition in the oil and gas exploration and production industry;
- a deterioration in general economic, business or industry conditions;
- negative public perceptions of our industry;
- limited control over properties we do not operate;
- pipeline and gathering system capacity constraints and transportation interruptions;
- terrorist activities and/or cyber-attacks adversely impacting our operations;
- potential challenges of our spin-off of Seventy Seven Energy Inc. (SSE) in connection with SSE's recently completed bankruptcy under Chapter 11 of the U.S. Bankruptcy Code;
- an interruption in operations at our headquarters due to a catastrophic event;
- the continuation of suspended dividend payments on our common stock and preferred stock;
- certain anti-takeover provisions that affect shareholder rights; and
- our inability to increase or maintain our liquidity through debt repurchases, capital exchanges, asset sales, joint ventures, farmouts or other means.

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 except as required by applicable law. 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

Oil, Natural Gas and NGL Derivatives

Our results of operations and cash flows are impacted by changes in market prices for oil, natural gas 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 share of production. We believe our derivative instruments continue to be highly effective in achieving our risk management objectives.

Our general strategy for protecting short-term cash flow and attempting to mitigate exposure to adverse oil, natural gas and NGL price changes is to hedge into strengthening oil and natural gas futures markets when prices reach levels that management believes are 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, oil and natural gas storage inventory levels, industry decline rates for base production and weather trends.

We use derivative instruments to achieve our risk management objectives, including swaps and options. All of these are described in more detail below. We typically use swaps for a large portion of the oil and natural gas price risk we hedge. We have also sold calls, taking advantage of premiums associated with market price volatility. In 2012 and 2013, we bought oil and natural gas calls to, in effect, lock in sold call positions. Due to lower oil, natural gas and NGL prices, we were able to achieve this at a low cost to us. In some cases, we deferred the payment of the premium on these trades to the related month of production.

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 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 volumes in excess of our share of forecasted production, and if production estimates were lowered for future periods and derivative instruments are already executed for some volume above the new production forecasts, the positions would be reversed. The actual fixed price on our derivative instruments is derived from the reference NYMEX price, as reflected in current NYMEX trading. The pricing dates of our derivative contracts follow NYMEX futures. All of our commodity 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 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 this 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 review when deciding to enter into the original derivative position. Gains or losses related to closed positions will be recognized 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 counterparty valuations for reasonableness. Derivative transactions are also subject to the risk that counterparties will be unable to meet their obligations. This 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 commodity hedging arrangements which require 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 8 of the notes to our condensed consolidated financial statements included in Item 1 of this report for further discussion of the fair value measurements associated with our derivatives.

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As of September 30, 2016, our oil and natural gas 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. In exchange for higher fixed prices on certain of our swap trades, we granted options that allow the counterparty to double the notional amount.
- 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 the excess on sold call options, and Chesapeake receives the 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.
- 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 prices, no payments are due from either party.
- Basis Protection Swaps: These instruments are arrangements that guarantee a fixed price differential to NYMEX from a specified delivery point. Chesapeake receives the fixed price differential and pays the floating market price differential to the counterparty for the hedged commodity.

As of September 30, 2016, we had the following open oil, natural gas and NGL derivative instruments:

		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmbbl)	($ per bbl)				($ in millions)
Oil:						
Swaps[a]:						
Short-term	18.0	$48.45	$ —	$ —	$ —	$ (37)
Long-term	3.8	49.42	—	—	—	(12)
Call Options (sold):						
Short-term	7.4	—	85.26	—	—	(1)
Long-term	1.3	—	83.50	—	—	(1)
Total Oil						$ (51)
	(tbtu)	($ per mmbtu)				($ in millions)
Natural Gas:						
Swaps[b]:						
Short-term	523	$2.98	$ —	$ —	$ —	$ (41)
Long-term	117	3.08	—	—	—	(2)
Collars:						
Short-term	38	—	3.48	3.00	—	1
Call Options (sold):						
Short-term	129	—	6.71	—	—	(6)
Long-term	78	—	11.60	—	—	—
Call Options (bought)[c]:						
Short-term	(47)	—	6.02	—	—	(20)
Basis Protection Swaps:						
Short-term	37	—	—	—	—	3
Long-term	7	—	—	—	(0.54)	(2)
Total Natural Gas						$ (67)

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		Weighted Average Price				Fair Value
	Volume	Fixed	Call	Put	Differential	Asset (Liability)
	(mmgal)	($ per mgal)				($ in millions)
NGL:						
Ethane Swaps:						
Short-term	19	$0.17	$ —	$ —	$ —	$ (1)
Propane Swaps:						
Short-term	17	0.46	—	—	—	(2)
Total NGL						$ (3)
Total Oil, Natural Gas and NGL						$ (121)

(a) Certain hedging arrangements include a sold option to double the volume at an average price of $53.67/bbl covering 0.7 mmbbls, which are included in the sold call options.

(b) Certain hedging arrangements include a sold option to double the volume at an average price of $2.80/mmbtu covering 26 tbtus, which are included in the sold call options.

(c) Included in the fair value are deferred premiums of $20 million which will be included in oil, natural gas and NGL sales as realized gains (losses) in the remainder of 2016.

In addition to the open derivative positions disclosed above, as of September 30, 2016, we had $2 million of net derivative gains related to settled contracts for future production periods that will be recorded within oil, natural gas and NGL sales as realized gains (losses) on derivatives once they are transferred from either accumulated other comprehensive income or unrealized gains (losses) on derivatives in the month of related production, based on the terms specified in the original contract as noted below.

	September 30, 2016
	($ in millions)
Short-term	$ 63
Long-term	(61)
Total	$ 2

The table below reconciles the changes in fair value of our oil and natural gas derivatives during the Current Period. Of the $121 million fair value liability as of September 30, 2016, a $104 million liability relates to contracts maturing in the next 12 months and a $17 million liability relates to contracts maturing after 12 months. All open derivative instruments as of September 30, 2016 are expected to mature by December 31, 2022.

	September 30, 2016
	($ in millions)
Fair value of contracts outstanding, as of January 1, 2016	$ 267
Change in fair value of contracts	(111)
Contracts realized or otherwise settled	(282)
Fair value of contracts closed	5
Fair value of contracts outstanding, as of September 30, 2016	$ (121)

The change in oil and natural gas prices during the Current Period decreased the liability related to our derivative instruments by $111 million. This unrealized loss is recorded in oil, natural gas and NGL sales. We settled contracts in the Current Period that were in an asset position for $282 million. We terminated contracts that were in a liability position for $5 million. Realized gains and losses will be recorded in oil, natural gas and NGL sales in the month of related production.

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Interest Rate Derivatives

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates, using the earliest demand repurchase date for contingent convertible senior notes. As of September 30, 2016, we had total debt of $8.717 billion, including $6.473 billion of fixed rate debt at interest rates averaging 6.69% and $2.244 billion of floating rate debt at an interest rate of 6.88%.

	Years of Maturity						
	2016	2017	2018	2019	2020	Thereafter	Total
	($ in millions)						
Liabilities:							
Debt – fixed rate[(a)]	$—	$662	$667	$—	$1,100	$4,044	$6,473
Average interest rate	—%	5.60 %	5.70 %	— %	6.68 %	7.03 %	6.69 %
Debt – variable rate	$—	$—	$—	$744	$—	$1,500	$2,244
Average interest rate	—%	— %	— %	3.61 %	— %	8.50 %	6.88 %

(a) This amount does not include the premium and deferred financing costs included in debt of $954 million and interest rate derivatives of $6 million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving credit facility and our floating rate senior notes. 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.

From time to time, we enter into interest rate derivatives, including 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 and 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 revolving credit facility borrowings. As of September 30, 2016, there were no interest rate derivatives outstanding.

As of September 30, 2016, we had $31 million of net gains related to settled derivative contracts that will be recorded within interest expense as realized gains or losses once they are transferred from our senior note liability or within interest expense as unrealized gains or 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.

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 senior 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. In the Current Quarter, in connection with our tender offers, we retired €36 million in aggregate principal amount of our 6.25% Euro-denominated Senior Notes due 2017, and we simultaneously unwound the cross currency swaps for the same principal amount at a cost of $8 million. Under the terms of the remaining cross currency swaps, on each semi-annual interest payment date, the counterparties pay us €8 million and we pay the counterparties $13 million, which yields an annual dollar-equivalent interest rate of 7.491%. Upon maturity of the notes, the counterparties will pay us €266 million and we will pay the counterparties $355 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 sheets as liabilities of $56 million and $52 million as of September 30, 2016 and December 31, 2015, respectively. The euro-denominated debt in long-term debt has been adjusted to $299 million as of September 30, 2016, using an exchange rate of $1.1235 to €1.00.

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Supply Contract Derivatives

As discussed in Note 8 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report, we enter into supply contracts in the normal course of business under which we commit to deliver a predetermined quantity of natural gas to certain counterparties in an attempt to earn attractive margins. Under certain contracts, we receive a sales price that is based on the price of a product other than natural gas thereby creating an embedded derivative. The prices of the products other than natural gas are unobservable. We engage an independent third-party valuation firm to value these supply contracts. The products being valued other than natural gas are sensitive to pricing fluctuations and some of these fluctuations could be material. Changes to the value of these contracts are recorded as mark-to-market adjustments to marketing, gathering and compression revenues in our condensed consolidated financial statements.

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 our 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 our Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2016.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the quarter ended September 30, 2016, which materially affected, or was reasonably likely to materially affect, our internal control over financial reporting.

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PART II

ITEM 1. Legal Proceedings

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 or may seek damages and penalties, the amount of which is currently indeterminate. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for information regarding our estimation and provision for potential losses related to litigation and regulatory proceedings.

2016 Shareholder Litigation. On April 19, 2016, a derivative action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and current and former directors and officers of the Company alleging, among other things, violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act, breach of fiduciary duties, waste of corporate assets, gross mismanagement and violations of Sections 10(b) and Rule 10b-5 of the Exchange Act related to actions allegedly taken by such persons since 2008. The lawsuit seeks certification as a class action, damages, attorneys' fees and other costs.

Regulatory and Related Proceedings. The Company has received, from the U.S. Department of Justice (DOJ) and certain state governmental agencies and authorities, subpoenas and demands for documents, information and testimony in connection with investigations into possible violations of federal and state antitrust laws relating to our purchase and lease of oil and natural gas rights in various states. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices. Chesapeake has engaged in discussions with the DOJ, U.S. Postal Service and state agency representatives and continues to respond to such subpoenas and demands.

In addition, the Company received a DOJ subpoena and a voluntary document request from the SEC seeking information on our accounting methodology for the acquisition and classification of oil and natural gas properties and related matters. Chesapeake has engaged in discussions with the DOJ and SEC about these matters. On October 4, 2016, a securities class action was filed in the U.S. District Court for the Western District of Oklahoma against the Company and certain current directors and officers of the Company alleging, among other things, violations of federal securities laws for purported misstatements in the Company's SEC filings and other public disclosures regarding the Company's accounting for the acquisition and classification of oil and natural gas properties. The lawsuit seeks certification as a class action, damages, attorneys' fees and other costs.

Redemption of 2019 Notes. See Note 4 of the notes to our condensed consolidated financial statements included in Item 1 of Part I of this report for a description of pending litigation regarding our redemption in May 2013 of our 6.775% Senior Notes due 2019 (the 2019 Notes).

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 oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. The Company has successfully defended a number of these failure-to-close cases in various courts, has settled and resolved other such cases and disputes and believes that its remaining loss exposure for these claims will not have a material adverse effect on the Company's financial position, results of operations or cash flows.

Regarding royalty claims, Chesapeake and other natural gas producers have been named in various lawsuits alleging royalty underpayment. The suits against us allege, among other things, 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 has resolved a number of these claims through negotiated settlements of past and future royalties and has prevailed in various other lawsuits. We are currently defending lawsuits seeking damages with respect to royalty underpayment in various states, including, but not limited to, Texas, Pennsylvania, Ohio, Oklahoma, Kentucky, Louisiana and Arkansas. These lawsuits include cases filed by individual royalty owners and putative class actions, some of which seek to certify a statewide class. The Company also has received DOJ, U.S. Postal Service and state subpoenas seeking information on the Company's royalty payment practices.

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Chesapeake is defending numerous lawsuits filed by individual royalty owners alleging royalty underpayment with respect to properties in Texas. On April 8, 2015, Chesapeake obtained a transfer order to move a substantial portion of these lawsuits to the 348th District Court of Tarrant County for pre-trial purposes (MDL). These lawsuits, which primarily relate to the Barnett Shale, generally allege that Chesapeake underpaid royalties by making improper deductions and using incorrect production volumes. Chesapeake has entered into a settlement agreement with MDL plaintiffs representing over 97% of the hydrocarbons at issue by volume and, on July 22, 2016, the plaintiffs who accepted the settlement filed to dismiss such lawsuits. Chesapeake funded the settlement amount of approximately $29 million in cash. Chesapeake also signed a $10 million, three-year promissory note in July 2016, which is accrued for as of September 30, 2016. Additional plaintiffs are continuing to accept the settlement on a rolling basis. Chesapeake expects that additional lawsuits filed by plaintiffs not participating in the settlement will continue to be pursued and that new plaintiffs will file other lawsuits making similar allegations.

On December 9, 2015, the Commonwealth of Pennsylvania, by the Office of Attorney General, filed a lawsuit in the Bradford County Court of Common Pleas related to royalty underpayment and lease acquisition and accounting practices with respect to properties in Pennsylvania. The lawsuit, which primarily relates to the Marcellus Shale and Utica Shale, alleges that Chesapeake violated the Pennsylvania Unfair Trade Practices and Consumer Protection Law (UTPCPL) by making improper deductions and entering into arrangements with affiliates that resulted in underpayment of royalties. The lawsuit seeks statutory restitution, civil penalties and costs, as well as temporary injunction from exploration and drilling activities in Pennsylvania until restitution, penalties and costs have been paid and permanent injunction from further violations of the UTPCPL. On February 8, 2016, the Office of Attorney General amended the complaint to, among other things, add an additional UTPCPL claim and antitrust claim alleging that a joint exploration agreement to which Chesapeake is a party established unlawful market allocation for the acquisition of leases. In response to Chesapeake’s preliminary objections, the Office of Attorney General filed a second amended complaint on May 3, 2016, alleging further violations of the UTPCPL based upon alleged predicate violations of the federal Sherman Act and the Federal Trade Commission Act. Chesapeake removed the case to the United States District Court for the Middle District of Pennsylvania on May 27, 2016. On August 15, 2016, the federal court remanded the case to state court.

Putative statewide class actions in Pennsylvania and Ohio and purported class arbitrations in Pennsylvania have been filed on behalf of royalty owners asserting various claims for damages related to alleged underpayment of royalties as a result of the Company’s divestiture of substantially all of its midstream business and most of its gathering assets in 2012 and 2013. These cases include claims for violation of and conspiracy to violate the federal Racketeer Influenced and Corrupt Organizations Act and for an unlawful market allocation agreement for mineral rights. One of the cases includes claims of intentional interference with contractual relations and violations of antitrust laws related to purported markets for gas mineral rights, operating rights and gas gathering sources.

The Company is also defending lawsuits alleging various violations of the Sherman Antitrust Act and state antitrust laws. In 2016, putative class action lawsuits have been filed in the United States District Court for the Western District of Oklahoma and in Oklahoma state courts, and an individual lawsuit was filed in the United States District Court of Kansas, in each case against the Company and other defendants. The lawsuits generally allege that, since 2007 and continuing through April 2013, the defendants conspired to rig bids and depress the market for the purchases of oil and natural gas leasehold interests and properties in the Anadarko Basin containing producing oil and natural gas wells. The lawsuits seek damages, attorney’s fees, costs and interest, as well as enjoinment from adopting practices or plans which would restrain competition in a similar manner as alleged in the lawsuits.

In April 2016, a class action lawsuit on behalf of holders of the Company's 6.875% Senior Notes due 2020 (the 2020 Notes) and 6.125% Senior Notes due 2021 (2021 Notes) was filed in the U.S. District Court for the Southern District of New York relating to the Company's December 2015 debt exchange, whereby the Company privately exchanged newly issued 8.00% Senior Secured Second Lien Notes due 2022 (Second Lien Notes) for certain outstanding senior unsecured notes and contingent convertible notes. The lawsuit alleges that the Company violated the Trust Indenture Act of 1939 and the implied covenant of good faith and fair dealing by benefiting themselves and a minority of noteholders who are qualified institutional buyers (QIBs). According to the lawsuit, as a result of the Company's private debt exchange in which only QIBs (and non-U.S. persons under Regulation S) were eligible to participate, the Company unjustly enriched itself at the expense of class members by reducing indebtedness and reducing the value of the 2020 Notes and the 2022 Notes. The lawsuit seeks damages and attorney's fees, in addition to declaratory relief that the debt exchange and the liens created for the benefit of the Second Lien Notes are null and void and that the debt exchange effectively resulted in a default under the indentures for the 2020 Notes and the 2021 Notes. In June 2016, the lawsuit was transferred to the United States District Court for the Western District of Oklahoma, and in October 2016, the Company filed a motion to dismiss for failure to state a claim. A hearing date for the motion has not been set.

Environmental Proceedings

Our subsidiary Chesapeake Appalachia, LLC (CALLC) is engaged in discussions with the U.S. Environmental Protection Agency, the U.S. Army Corps of Engineers and the Pennsylvania Department of Environmental Protection (PADEP) regarding potential violations of the permitting requirements of the federal Clean Water Act, the Pennsylvania Clean Streams Law and the Pennsylvania Dam Safety and Encroachments Act in connection with the placement of dredge and fill material during construction of certain sites in Pennsylvania. CALLC identified the potential violations in connection with an internal review of its facilities siting and construction processes and voluntarily reported them to the regulatory agencies. Resolution of the matter may result in monetary sanctions of more than $100,000.

CALLC and the PADEP are also engaged in discussions regarding alleged violations of the Pennsylvania Oil and Gas Act and the Pennsylvania Clean Streams Law in connection with contamination in the vicinity of one of CALLC's well pads in Sullivan County, Pennsylvania. Resolution of the matter may result in monetary sanctions of more than $100,000.

On February 16, 2016, we were named as a defendant in a lawsuit brought in the U.S. District Court for the Western District of Oklahoma by the Sierra Club. The complaint alleges that we and the other defendants, all exploration and production companies, have violated the federal Resource Conservation and Recovery Act by operating produced water disposal wells in a manner that has caused earthquakes. It requests a court order requiring substantial reduction of the amounts of produced water disposed of in such manner, the creation of an earthquake prediction center, and the reinforcement of purportedly vulnerable structures that could be impacted by earthquakes.

On October 14, 2016, we were named as a defendant in a putative class action in the U.S. District Court for the Western District of Oklahoma, alleging that we and the other defendants have operated produced water disposal wells in a manner that has caused earthquakes. The proposed class would consist of property owners in a twenty-five county area of Oklahoma. The petition seeks, among other relief, reimbursement of insurance premiums and an award of damages for injury to real property.

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 2015 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.

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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, 2016:

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 Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs[(b)] ($ in millions)
July 1, 2016 through July 31, 2016	277,382	$ 4.61	—	$ —
August 1, 2016 through August 31, 2016	2,706	$ 6.35	—	$ —
September 1, 2016 through September 30, 2016	2,703	$ 6.78	—	$ —
Total	282,791	$ 4.65	—	

(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. Also includes shares of common stock purchased on behalf of Chesapeake's deferred compensation plan related to participant deferrals and Company matching contributions.

(b) In December 2014, the Company's Board of Directors authorized the repurchase of up to $1 billion in value of its common stock from time to time. The repurchase program does not have an expiration date. As of September 30, 2016, no repurchases had been made under the program.

ITEM 3. Defaults Upon Senior Securities

In January 2016, our Board of Directors determined to suspend dividend payments on our preferred stock. Suspension of the dividends did not constitute an event of default under our revolving credit facility or bond indentures. However, as a result of such suspension, we are in arrears in the payment of dividends with respect to our 5.75% Cumulative Convertible Preferred Stock, 5.75% Cumulative Convertible Preferred Stock (series A), 5.00% Cumulative Convertible Preferred Stock (series 2005B) and 4.50% Cumulative Convertible Preferred Stock. The table below details our preferred stock dividends as of September 30, 2016 (paid in arrears).

	5.75%	5.75% (A)	4.50%	5.00% (2005B)
	($ in millions)			
Dividends in arrears	$63	$ 48	$ 7	$ 9

ITEM 4. Mine Safety Disclosures

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. Exhibits

The exhibits listed below in the Index of Exhibits (following the signatures page) are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

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SIGNATURES

Pursuant to the requirements 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 3, 2016	By:	/s/ ROBERT D. LAWLER Robert D. Lawler, President and Chief Executive Officer
Date: November 3, 2016	By:	/s/ DOMENIC J. DELL'OSSO, JR. Domenic J. Dell'Osso, Jr. Executive Vice President and Chief Financial Officer

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INDEX OF EXHIBITS

Exhibit Number	Exhibit Description	Incorporated by Reference				Filed or Furnished Herewith
		Form	SEC File Number	Exhibit	Filing Date	
3.1.1	Chesapeake's Restated Certificate of Incorporation.	10-Q	001-13726	3.1.1	8/6/2014	
3.1.2	Certificate of Amendment to Restated Certificate of Incorporation	8-K	001-13726	3.1.2	5/20/2016	
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B), as amended.	10-Q	001-13726	3.1.4	11/10/2008	
3.1.4	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock, as amended.	10-Q	001-13726	3.1.6	8/11/2008	
3.1.5	Certificate of Designation of 5.75% Cumulative Non-Voting Convertible Preferred Stock (Series A).	8-K	001-13726	3.2	5/20/2010	
3.1.6	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	6/9/2014	
4.1	Term Loan Agreement dated August 23, 2016 among Chesapeake Energy Corporation, the lenders party thereto and Deutsche Bank Trust Company Americas, as term agent.	8-K	001-13726	4.1	8/24/2016	
4.2	Class A Term Loan Supplement dated August 23, 2016 among Chesapeake Energy Corporation, the lenders party thereto and Deutsche Bank Trust Company Americas, as term agent.	8-K	001-13726	4.2	8/24/2016	
4.3	Indenture dated as of October 5, 2016, among Chesapeake Energy Corporation, the subsidiary guarantors named therein and Deutsche Bank Trust Company Americas, as trustee.	8-K	001-13726	4.1	10/5/2016	
10.1	Collateral Trust Agreement, dated as of August 23, 2016 by and among MUFG Union Bank, N.A., as collateral trustee and revolver agent, and Deutsche Bank Trust Company Americas, as term loan agent, and acknowledged and agreed by Chesapeake Energy Corporation and certain of its subsidiaries.	8-K	001-13726	10.1	8/24/2016	
12	Ratios of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Dividends.					X

31.1	Robert D. Lawler, President and 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

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32.1	Robert D. Lawler, President and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
32.2	Domenic J. Dell'Osso, Jr., Executive Vice President and Chief Financial Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	X
101.INS	XBRL Instance Document.	X
101.SCH	XBRL Taxonomy Extension Schema Document.	X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.	X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.	X
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document.	X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.	X