

SOUTHWESTERN ENERGY CO

Form 10-Q

October 26, 2017

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)

Quarterly Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the quarterly period ended September 30, 2017

Or

Transition Report pursuant to Section 13 or 15(d) of the Securities

Exchange Act of 1934

For the transition period from _____ to _____

Commission file number: 001-08246

Southwestern Energy Company

(Exact name of registrant as specified in its charter)

Delaware 71-0205415
(State or other jurisdiction of incorporation (I.R.S. Employer Identification No.)
or organization)

10000 Energy Drive

Spring, Texas 77389
(Address of principal executive offices) (Zip Code)

(832) 796-1000
(Registrant's telephone number, including area code)

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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 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 No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer”, “accelerated filer”, “smaller reporting company” and “emerging growth company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
-------------------------	-------------------	-----------------------	---------------------------	-------------------------

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

Indicate the number of shares outstanding of each of the issuer’s classes of common stock, as of the latest practicable date:

Class	Outstanding as of October 24, 2017
Common Stock, Par Value \$0.01	512,425,656

Table of Contents

SOUTHWESTERN ENERGY COMPANY

INDEX TO FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2017

PART I – FINANCIAL INFORMATION

Item 1.	<u>Financial Statements</u>	3
	<u>Condensed Consolidated Statements of Operations</u>	3
	<u>Condensed Consolidated Statements of Comprehensive Income</u>	4
	<u>Condensed Consolidated Balance Sheets</u>	5
	<u>Condensed Consolidated Statements of Cash Flows</u>	6
	<u>Condensed Consolidated Statements of Changes in Equity</u>	7
	<u>Notes to Unaudited Condensed Consolidated Financial Statements</u>	8
Item 2.	<u>Management’s Discussion and Analysis of Financial Condition and Results of Operations</u>	27
	<u>Results of Operations</u>	28
	<u>Liquidity and Capital Resources</u>	34
Item 3.	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	39
Item 4.	<u>Controls and Procedures</u>	40

PART II – OTHER INFORMATION

Item 1.	<u>Legal Proceedings</u>	40
Item 1A.	<u>Risk Factors</u>	40
Item 2.	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	40
Item 3.	<u>Defaults Upon Senior Securities</u>	40
Item 4.	<u>Mine Safety Disclosures</u>	40
Item 5.	<u>Other Information</u>	40
Item 6.	<u>Exhibits</u>	41

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future

operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Quarterly Report on Form 10-Q identified by words such as “anticipate,” “intend,” “plan,” “project,” “estimate,” “continue,” “potential,” “should,” “could,” “may,” “will,” “guidance,” “outlook,” “effort,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “forecast,” “target” or similar w

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

1

Table of Contents

- the timing and extent of changes in market conditions and prices for natural gas, oil and Natural Gas Liquids (“NGLs”) (including regional basis differentials);
- our ability to fund our planned capital investments;
- a change in our credit rating;
- the extent to which lower commodity prices impact our ability to service or refinance our existing debt;
- the impact of volatility in the financial markets or other global economic factors;
- difficulties in appropriately allocating capital and resources among our strategic opportunities;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to maintain leases that may expire if production is not established or profitably maintained;
- our ability to realize the expected benefits from recent acquisitions;
- our ability to transport our production to the most favorable markets or at all;
- availability and costs of personnel and of products and services provided by third parties;
- the impact of government regulation, including the ability to obtain and maintain permits, any increase in severance or similar taxes, and legislation relating to hydraulic fracturing, climate and over-the-counter derivatives;
- the impact of the adverse outcome of any material litigation against us;
- the effects of weather;
- increased competition and regulation;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission (“SEC”).

Should one or more of the risks or uncertainties described above or elsewhere in this Quarterly Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

Table of Contents

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
	(in millions, except share/per share amounts)			
Operating Revenues:				
Gas sales	\$ 394	\$ 340	\$ 1,368	\$ 906
Oil sales	27	19	73	50
NGL sales	55	22	132	59
Marketing	233	237	736	631
Gas gathering	28	33	85	106
	737	651	2,394	1,752
Operating Costs and Expenses:				
Marketing purchases	236	234	740	627
Operating expenses	170	139	481	455
General and administrative expenses	62	61	170	171
Restructuring charges	–	2	–	77
Depreciation, depletion and amortization	135	99	364	349
Impairment of natural gas and oil properties	–	817	–	2,321
Taxes, other than income taxes	24	24	75	69
	627	1,376	1,830	4,069
Operating Income (Loss)	110	(725)	564	(2,317)
Interest Expense:				
Interest on debt	58	59	175	168
Other interest charges	2	8	7	12
Interest capitalized	(29)	(41)	(85)	(123)
	31	26	97	57
Gain (Loss) on Derivatives	45	71	295	(28)
Loss on Early Extinguishment of Debt	(59)	(51)	(70)	(51)
Other Income (Loss), Net	(2)	3	6	–
Income (Loss) Before Income Taxes	63	(728)	698	(2,453)
Benefit for Income Taxes:				
Current	(10)	–	(10)	–

Edgar Filing: SOUTHWESTERN ENERGY CO - Form 10-Q

Deferred	(4)	(20)	(4)	(20)
	(14)	(20)	(14)	(20)
Net Income (Loss)	\$ 77	\$ (708)	\$ 712	\$ (2,433)
Mandatory convertible preferred stock dividend	27	27	81	81
Participating securities - mandatory convertible preferred stock	7	–	83	–
Net Income (Loss) Attributable to Common Stock	\$ 43	\$ (735)	\$ 548	\$ (2,514)
Earnings (Loss) Per Common Share:				
Basic	\$ 0.09	\$ (1.52)	\$ 1.11	\$ (6.02)
Diluted	\$ 0.09	\$ (1.52)	\$ 1.10	\$ (6.02)
Weighted Average Common Shares Outstanding:				
Basic	499,812,926	482,485,150	496,458,435	417,222,661
Diluted	502,290,779	482,485,150	498,527,671	417,222,661

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

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
 CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
 (Unaudited)

	For the three months ended September 30, 2017 2016		For the nine months ended September 30, 2017 2016	
	(in millions)			
Net income (loss)	\$ 77	\$ (708)	\$ 712	\$ (2,433)
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost and net loss included in net periodic pension cost (1)	1	1	2	1
Net gain incurred in period (1)	–	1	–	5
Change in currency translation adjustment	–	–	–	3
Comprehensive income (loss)	\$ 78	\$ (706)	\$ 714	\$ (2,424)
(1) Net of tax for the three and nine months ended September 30, 2017 and 2016.				

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

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
 CONDENSED CONSOLIDATED BALANCE SHEETS
 (Unaudited)

	September 30, 2017	December 31, 2016
	(in millions)	
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 989	\$ 1,423
Accounts receivable, net	360	363
Derivative assets	91	51
Other current assets	36	35
Total current assets	1,476	1,872
Natural gas and oil properties, using the full cost method, including \$1,919 million as of September 30, 2017 and \$2,105 million as of December 31, 2016 excluded from amortization	23,575	22,653
Gathering systems	1,311	1,299
Other	568	537
Less: Accumulated depreciation, depletion and amortization	(19,904)	(19,534)
Total property and equipment, net	5,550	4,955
Other long-term assets	176	249
TOTAL ASSETS	\$ 7,202	\$ 7,076
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	\$ 40	\$ 41
Accounts payable	502	473
Taxes payable	55	59
Interest payable	21	74
Dividends payable	27	27
Derivative liabilities	97	355
Other current liabilities	42	35
Total current liabilities	784	1,064
Long-term debt	4,396	4,612
Pension and other postretirement liabilities	46	49
Other long-term liabilities	324	434
Total long-term liabilities	4,766	5,095
Commitments and contingencies (Note 10)		
Equity:		
Common stock, \$0.01 par value; 1,250,000,000 shares authorized; issued 509,142,659 shares as of September 30, 2017 (does not include 3,346,703 shares issued on October 16, 2017 on account of a dividend declared on September 15, 2017) and 495,248,369 as of December 31, 2016	5	5
Preferred stock, \$0.01 par value, 10,000,000 shares authorized, 6.25% Series B Mandatory Convertible, \$1,000 per share liquidation preference, 1,725,000 shares issued and outstanding	—	—

Edgar Filing: SOUTHWESTERN ENERGY CO - Form 10-Q

as of September 30, 2017 and December 31, 2016, conversion in January 2018

Additional paid-in capital	4,698	4,677
Accumulated deficit	(3,013)	(3,725)
Accumulated other comprehensive loss	(37)	(39)
Common stock in treasury, 31,269 shares as of September 30, 2017 and December 31, 2016	(1)	(1)
Total equity	1,652	917
TOTAL LIABILITIES AND EQUITY	\$ 7,202	\$ 7,076

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

5

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
 CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
 (Unaudited)

	For the nine months ended September 30, 2017 2016 (in millions)	
Cash Flows From Operating Activities:		
Net income (loss)	\$ 712	\$ (2,433)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	364	349
Impairment of natural gas and oil properties	–	2,321
Amortization of debt issuance costs	7	12
Deferred income taxes	(4)	(20)
(Gain) loss on derivatives, unsettled	(350)	48
Stock-based compensation	19	24
Restructuring charges	–	30
Loss on early extinguishment of debt	70	51
Other	(2)	5
Change in assets and liabilities:		
Accounts receivable	3	53
Accounts payable	16	(72)
Taxes payable	(3)	(17)
Interest payable	(28)	(14)
Other assets and liabilities	(15)	–
Net cash provided by operating activities	789	337
Cash Flows From Investing Activities:		
Capital investments	(943)	(391)
Proceeds from sale of property and equipment	17	434
Other	5	–
Net cash provided by (used in) investing activities	(921)	43
Cash Flows From Financing Activities:		
Payments on short-term debt	(287)	(1)
Payments on long-term debt	(1,139)	(1,175)
Payments on revolving credit facility	–	(3,268)
Borrowings under revolving credit facility	–	3,152
Payments on commercial paper	–	(242)
Borrowings under commercial paper	–	242

Edgar Filing: SOUTHWESTERN ENERGY CO - Form 10-Q

Change in bank drafts outstanding	–	(19)
Proceeds from issuance of long-term debt	1,150	1,191
Debt issuance costs	(18)	(17)
Proceeds from issuance of common stock	–	1,247
Preferred stock dividend	(8)	(27)
Other	–	(4)
Net cash provided by (used in) financing activities	(302)	1,079
Increase (decrease) in cash and cash equivalents	(434)	1,459
Cash and cash equivalents at beginning of year	1,423	15
Cash and cash equivalents at end of period	\$ 989	\$ 1,474

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

6

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES
 CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
 (Unaudited)

	Common Stock		Preferred Stock	Additional	Accumulated	Other	Common	
	Shares	Amount	Shares	Paid-In	Accumulated	Comprehensive	Stock	
	Issued	Issued	Issued	Capital	Deficit (1)	Income	Treasury	Total
	(in millions, except share amounts)							
Balance at December 31, 2016	495,248,369	\$ 5	1,725,000	\$ 4,677	\$ (3,725)	\$ (39)	\$ (1)	\$ 917
Comprehensive income:								
Net income	—	—	—	—	712	—	—	712
Other comprehensive income	—	—	—	—	—	2	—	2
Total comprehensive income	—	—	—	—	—	—	—	714
Stock-based compensation	—	—	—	29	—	—	—	29
Preferred stock dividend (2)	9,445,013	—	—	(8)	—	—	—	(8)
Issuance of restricted stock	5,036,122	—	—	—	—	—	—	—
Cancellation of restricted stock	(609,130)	—	—	—	—	—	—	—
Performance units vested	121,208	—	—	—	—	—	—	—
Tax withholding – stock compensation	(98,995)	—	—	—	—	—	—	—
Issuance of stock awards	72	—	—	—	—	—	—	—
Balance at September 30, 2017	509,142,659	\$ 5	1,725,000	\$ 4,698	\$ (3,013)	\$ (37)	\$ (1)	\$ 1,652

(1) Includes a net cumulative-effect adjustment of \$59 million related to the recognition of previously unrecognized windfall tax benefits resulting from the adoption of ASU 2016-09 as of the beginning of 2017. This adjustment increased net deferred tax assets and the related income tax valuation allowance by the same amount.

- (2) Does not include 3,346,703 shares issued on October 16, 2017 and distributed to holders of the Company's mandatory convertible preferred stock.

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

7

Table of Contents

SOUTHWESTERN ENERGY COMPANY AND SUBSIDIARIES

NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(1) BASIS OF PRESENTATION

Southwestern Energy Company (including its subsidiaries, collectively “Southwestern” or the “Company”) is an independent energy company engaged in natural gas, oil and NGL exploration, development and production (“E&P”). The Company is also focused on creating and capturing additional value through its natural gas gathering and marketing businesses (“Midstream Services”). Southwestern conducts most of its businesses through subsidiaries and operates principally in two segments: E&P and Midstream Services.

The accompanying unaudited condensed consolidated financial statements were prepared using accounting principles generally accepted in the United States of America (“GAAP”) for interim financial information and in accordance with the rules and regulations of the Securities and Exchange Commission. Certain information relating to the Company’s organization and footnote disclosures normally included in financial statements prepared in accordance with GAAP have been appropriately condensed or omitted in this Quarterly Report. The Company believes the disclosures made are adequate to make the information presented not misleading.

The unaudited condensed consolidated financial statements contained in this report include all normal and recurring material adjustments that, in the opinion of management, are necessary for a fair statement of the financial position, results of operations and cash flows for the interim periods presented herein. It is recommended that these unaudited condensed consolidated financial statements be read in conjunction with the consolidated financial statements and the notes thereto included in the Company’s Annual Report for the year ended December 31, 2016 (“2016 Annual Report”).

The Company’s significant accounting policies, which have been reviewed and approved by the Audit Committee of the Company’s Board of Directors, are summarized in Note 1 in the Notes to the Consolidated Financial Statements included in the Company’s 2016 Annual Report.

(2) CASH AND CASH EQUIVALENTS

The following table presents a summary of cash and cash equivalents as of September 30, 2017 and December 31, 2016:

	September 30, 2017	December 31, 2016
	(in millions)	
Cash	\$ 259	\$ 254
Marketable securities (1)	680	1,169
Other cash equivalents (2)	50	–
Total cash and cash equivalents	\$ 989	\$ 1,423

(1) Consists of government stable value money market funds.

(2) Consists of time deposits.

(3) REDUCTION IN WORKFORCE

In January 2016, the Company announced a 40% workforce reduction as a result of lower anticipated drilling activity. This reduction was substantially completed in the first quarter of 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016.

The following table presents a summary of the restructuring charges for the three and nine months ended September 30, 2016:

	For the three months ended ended September 30, 2016	For the nine months ended ended September 30, 2016
	(in millions)	
Severance (including payroll taxes) (1)	\$ –	\$ 44
Stock-based compensation (2)	–	24
Pension and other postretirement benefits (3)	2	5
Other benefits	–	3
Outplacement services, other	–	1
Total restructuring charges (4)	\$ 2	\$ 77

Table of Contents

- (1) Includes \$1 million related to executive management restructuring for the nine months ended September 30, 2016.
- (2) Includes \$3 million related to executive management restructuring for the nine months ended September 30, 2016.
- (3) Includes non-cash charges related to the curtailment and settlement of the pension and other postretirement benefit plans. See Note 11 for additional details regarding the Company's pension and other postretirement benefit plans.
- (4) Total restructuring charges were \$2 million for the Company's E&P segment for the three months ended September 30, 2016. For the nine months ended September 30, 2016, restructuring charges were \$74 million and \$3 million for the Company's E&P and Midstream Services segments, respectively.

Severance payments and other separation costs related to restructuring were substantially completed by the end of 2016.

(4) NATURAL GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil properties. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized on a country-by-country basis and amortized over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs, net of applicable deferred taxes, to the aggregate of the present value of future net revenues attributable to proved natural gas, oil and NGL reserves discounted at 10% (standardized measure). Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas, oil and NGL prices may subsequently increase the ceiling. Companies using the full cost method are required to use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives designated for hedge accounting, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$3.00 per MMBtu, West Texas Intermediate oil of \$46.27 per barrel and NGLs of \$12.47 per barrel, adjusted for differentials, the Company's net book value of its United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at September 30, 2017. The Company had no hedge positions that were designated for hedge accounting as of September 30, 2017. Decreases in market prices as well as

changes in production rates, levels of reserves, evaluation of costs excluded from amortization, future development costs and production costs could result in future ceiling test impairments.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of \$2.28 per MMBtu, West Texas Intermediate oil of \$38.17 per barrel and NGLs of \$6.46 per barrel, adjusted for differentials, the net book value of the Company's United States natural gas and oil properties resulted in a non-cash ceiling test impairment of \$817 million for the three months ended September 30, 2016. The Company had no hedge positions that were designated for hedge accounting as of September 30, 2016. In the first and second quarters of 2016, the Company recognized non-cash ceiling test impairments of \$1,034 million and \$470 million, respectively.

(5) EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during the reportable period. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding: the incremental shares that would have been outstanding assuming the exercise of dilutive stock options, the vesting of unvested restricted shares of common stock, performance units and the assumed conversion of mandatory convertible preferred stock. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In July 2016, the Company completed an underwritten public offering of 98,900,000 shares of its common stock, with an offering price to the public of \$13.00 per share. Net proceeds from the common stock offering were approximately \$1,247 million, after underwriting discount and offering expenses. The proceeds from the offering were used to repay \$375 million of the \$750 million term loan entered into in November 2015 and to settle certain tender offers by purchasing an aggregate principal amount of approximately \$700 million of the Company's outstanding senior notes due in the first quarter of 2018. The remaining proceeds of the offering have been used for general corporate purposes.

Table of Contents

The depositary shares issued in January 2015 entitles the holder to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Unless converted earlier at the option of the holders, on or around January 15, 2018 each share of convertible preferred stock will automatically convert into between 37.0028 and 43.4782 shares of the Company's common stock (correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of the Company's common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of the Company's common stock over a 20 trading day averaging period immediately prior to that date. The total potential shares of common stock resulting from the conversion will range from 63,829,830 to 74,999,895 shares.

The mandatory convertible preferred stock has the non-forfeitable right to participate on an as-converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. Accordingly, it is included in the computation of basic and diluted earnings per share, pursuant to the two-class method. In the calculation of basic earnings per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company's participating securities do not participate in undistributed net losses because they are not contractually obligated to do so.

On September 15, 2017, the Company declared its quarterly dividend, payable to holders of the mandatory convertible preferred stock, and announced that it would pay the quarterly dividend in stock, in lieu of cash, to the extent permitted by the certificate of designations for the Series B preferred stock. The Company issued 3,346,703 shares of common stock on October 16, 2017 in partial payment for the dividend, the remaining \$7.9 million paid in cash.

The following table presents the computation of earnings per share for the three and nine months ended September 30, 2017 and 2016:

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
	(in millions, except share/per share amounts)			
Net income (loss)	\$ 77	\$ (708)	\$ 712	\$ (2,433)

Edgar Filing: SOUTHWESTERN ENERGY CO - Form 10-Q

Mandatory convertible preferred stock dividend	27	27	81	81
Participating securities - mandatory convertible preferred stock	7	–	83	–
Net income (loss) attributable to common stock	\$ 43	\$ (735)	\$ 548	\$ (2,514)
Number of common shares:				
Weighted average outstanding	499,812,926	482,485,150	496,458,435	417,222,661
Issued upon assumed exercise of outstanding stock options	–	–	–	–
Effect of issuance of non-vested restricted common stock	1,202,585	–	883,512	–
Effect of issuance of non-vested performance units	1,275,268	–	1,185,724	–
Effect of issuance of mandatory convertible preferred stock	–	–	–	–
Weighted average and potential dilutive outstanding	502,290,779	482,485,150	498,527,671	417,222,661
Earnings (loss) per common share:				
Basic	\$ 0.09	\$ (1.52)	\$ 1.11	\$ (6.02)
Diluted	\$ 0.09	\$ (1.52)	\$ 1.10	\$ (6.02)

The following table presents the common stock shares equivalent excluded from the calculation of diluted earnings per share for the three and nine months ended September 30, 2017 and 2016, as they would have had an antidilutive effect:

	For the three months ended		For the nine months ended	
	September 30, 2017	2016	September 30, 2017	2016
Unvested stock options	180,932	3,409,596	60,973	3,714,095
Unvested share-based payment	5,703,086	599,372	5,356,166	993,576
Performance units	1,036,422	935,330	1,036,422	762,171
Mandatory convertible preferred stock	74,999,895	74,999,895	74,999,895	74,999,895
Total	81,920,335	79,944,193	81,453,456	80,469,737

Table of Contents

(6) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas, oil and NGLs which impacts the predictability of its cash flows related to the sale of those commodities. These risks are managed by the Company's use of certain derivative financial instruments. As of September 30, 2017 and December 31, 2016, the Company's derivative financial instruments consisted of fixed price swaps, two-way costless collars, three-way costless collars, basis swaps, put and call options, and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps The Company receives a fixed price for the contract and pays a floating market price to the counterparty.

Purchased put options The Company purchases put options based on an index price from the counterparty by payment of a cash premium. If the index price is lower than the put's strike price at the time of settlement, the Company receives from the counterparty such difference between the index price and the purchased put strike price. If the market price settles above the put's strike price, no payment is due from either party.

Two-way costless collars Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.

Three-way costless collars Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.

Basis swaps Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Sold call options The Company sells call options in exchange for a premium. If the market price exceeds the strike price of the call option at the time of settlement, the Company pays the counterparty such excess on sold call options. If the market price settles below the call's strike price, no payment is due from either party.

Interest rate swaps Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

Table of Contents

The Company utilizes counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Company closely monitors the credit ratings of these counterparties.

Additionally, the Company performs both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. However, there can be no assurance that a counterparty will be able to meet its obligations to the Company.

The following table provides information about the Company's financial instruments that are sensitive to changes in commodity prices and that are used to protect the Company's exposure. None of the financial instruments below are designated for hedge accounting treatment. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates as of September 30, 2017:

	Volume (Bcf)	Weighted Average Price per MMBtu					Basis Differential	Fair Value at September 30, 2017 (in millions)
		Swaps	Sold Puts	Purchased Puts	Sold Calls			
Financial protection on production								
2017								
Fixed price swaps	73	\$ 3.06	\$ –	\$ –	\$ –	\$ –	\$ –	\$ 1
Two-way costless-collars	31	–	–	2.96	3.38	–	–	1
Three-way costless-collars	34	–	2.29	2.97	3.30	–	–	–
Total	138							\$ 2
2018								
Fixed price swaps	178	\$ 3.02	\$ –	\$ –	\$ –	\$ –	\$ –	\$ (4)
Two-way costless-collars	23	–	–	2.97	3.56	–	–	(1)
Three-way costless-collars	272	–	2.40	2.97	3.37	–	–	7
Total	473							\$ 2
2019								
Three-way costless-collars	108	\$ –	\$ 2.50	\$ 2.95	\$ 3.32	\$ –	\$ –	\$ (1)
Total	108							\$ (1)
Basis Swaps								
2017	32	\$ –	\$ –	\$ –	\$ –	\$ (0.95)	\$ –	\$ 12
2018	25	–	–	–	–	(0.63)	–	(16)
Total	57							\$ (4)

		Weighted Average Price per MMBtu	Fair Value at September 30, 2017 (in millions)	
	Volume (Bcf)	Sold Calls		
Call options				
2017	21	\$ 3.68	\$ –	(1)
2018	63	3.50	(9)	
2019	52	3.50	(8)	
2020	32	3.75	(5)	
Total	168		\$ (22)	

(1) Excludes \$2 million in premiums paid related to certain call options recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet. As certain call options settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the unaudited condensed consolidated statements of operations.

Table of Contents

The balance sheet classification of the assets and liabilities related to derivative financial instruments (none of which are designated for hedge accounting treatment) are summarized below as of September 30, 2017 and December 31, 2016:

	Derivative Assets		
	Balance Sheet Classification	Fair Value	
		September 30, 2017	December 31, 2016
		(in millions)	
Derivatives not designated as hedging instruments:			
Fixed price swaps	Derivative assets	\$ 12	\$ –
Two-way costless collars	Derivative assets	7	8
Three-way costless collars	Derivative assets	50	11
Basis swaps	Derivative assets	19	32
Call options	Derivative assets	1	–
Fixed price swaps	Other long-term assets	1	1
Two-way costless collars	Other long-term assets	–	2
Three-way costless collars	Other long-term assets	56	100
Basis swaps	Other long-term assets	–	1
Total derivative assets		\$ 146 (1)	\$ 155
	Derivative Liabilities		
	Balance Sheet Classification	Fair Value	
		September 30, 2017	December 31, 2016
		(in millions)	
Derivatives not designated as hedging instruments:			
Fixed price swaps	Derivative liabilities	\$ 14	\$ 175
Two-way costless collars	Derivative liabilities	7	49
Three-way costless collars	Derivative liabilities	44	70
Basis swaps	Derivative liabilities	23	13
Call options	Derivative liabilities	8	46
Interest rate swaps	Derivative liabilities	1	2
Fixed price swaps	Other long-term liabilities	2	3
Two-way costless collars	Other long-term liabilities	–	9
Three-way costless collars	Other long-term liabilities	56	122
Basis swaps	Other long-term liabilities	–	5
Call options	Other long-term liabilities	15	35
Interest rate swaps	Other long-term liabilities	1	1
Total derivative liabilities		\$ 171	\$ 530

(1) Excludes \$2 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet. As certain call options settle, the premium will be amortized and recognized as a component of gain (loss) on derivatives on the unaudited condensed consolidated statements of operations.

At September 30, 2017, the net fair value of the Company's financial instruments related to natural gas was a \$23 million liability. The net fair value of the Company's interest rate swaps was a \$2 million liability as of September 30, 2017. The Company had ethane fixed price swaps with an immaterial fair value as of September 30, 2017.

Derivative Contracts Not Designated for Hedge Accounting

As of September 30, 2017, the Company had no positions designated for hedge accounting treatment. Gains and losses on derivatives that are not designated for hedge accounting treatment, or that do not meet hedge accounting requirements, are recorded as a component of gain (loss) on derivatives on the unaudited condensed consolidated statements of operations. Accordingly, the gain (loss) on derivatives component of the statements of operations reflects the gains and losses on both settled and unsettled derivatives. The Company calculates gains and losses on settled derivatives as the summation of gains and losses on positions which have settled within the reporting period. Only the settled gains and losses are included in the Company's realized commodity price calculations.

The Company is a party to interest rate swaps that were entered into to mitigate the Company's exposure to volatility in interest rates. The interest rate swaps have a notional amount of \$170 million and expire in June 2020. The Company did not designate the interest rate swaps for hedge accounting treatment. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives on the unaudited condensed consolidated statements of operations.

Table of Contents

The following tables summarize the before-tax effect of fixed price swaps, purchased put options, two-way costless collars, three-way costless collars, basis swaps, call options and interest rate swaps not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2017 and 2016:

Derivative Instrument	Consolidated Statements of Operations Classification of Gain (Loss) on Derivatives, Unsettled	Gain (Loss) on Derivatives, Unsettled			
		Recognized in Earnings For the three months ended September 30,		For the nine months ended September 30,	
		2017	2016	2017	2016
		(in millions)			
Fixed price swaps (1)	Gain (Loss) on Derivatives	\$ (2)	\$ 23	\$ 174	\$ (17)
Two-way costless collars	Gain (Loss) on Derivatives	3	5	48	–
Three-way costless collars	Gain (Loss) on Derivatives	(1)	1	87	(1)
Basis swaps	Gain (Loss) on Derivatives	24	31	(19)	27
Call options	Gain (Loss) on Derivatives	6	21	59	(54)
Interest rate swaps	Gain (Loss) on Derivatives	1	–	1	(3)
Total gain (loss) on unsettled derivatives		\$ 31	\$ 81	\$ 350	\$ (48)
Derivative Instrument	Consolidated Statements of Operations Classification of Gain (Loss) on Derivatives, Settled	Gain (Loss) on Derivatives, Settled (2)			
		Recognized in Earnings For the three months ended September 30,		For the nine months ended September 30,	
		2017	2016	2017	2016
		(in millions)			
Fixed price swaps (1)	Gain (Loss) on Derivatives	\$ 7	\$ (9)	\$ (18)	\$ 7
Purchased put options	Gain (Loss) on Derivatives	–	–	–	11
Two-way costless collars	Gain (Loss) on Derivatives	–	–	(3)	–
Three-way costless collars	Gain (Loss) on Derivatives	1	–	(4)	–
Basis swaps	Gain (Loss) on Derivatives	9	–	(21)	4
Call options	Gain (Loss) on Derivatives	–	–	(6)	–
Interest rate swaps	Gain (Loss) on Derivatives	–	(1)	–	(2)
Total gain (loss) on settled derivatives (3) (4)		\$ 17	\$ (10)	\$ (52)	\$ 20

Total gain (loss) on derivatives (4) \$ 48 \$ 71 \$ 298 \$ (28)

- (1) Includes the Company's fixed price swaps on natural gas and ethane. As of September 30, 2017, the amount of unsettled and settled fixed price swaps related to ethane was immaterial.
- (2) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.
- (3) Excluding interest rate swaps and settled ethane fixed price swaps, these amounts are included, along with gas sales revenues, in the calculation of the Company's realized natural gas price. Settled ethane fixed price swaps are included, along with NGL sales revenues, in the calculation of the Company's realized NGL price.
- (4) Excludes \$3 million amortization of premiums paid related to certain call options for the three and nine months ended September 30, 2017, which is included in gain (loss) on derivatives on the condensed consolidated statements of operations.

Derivative Contracts Designated for Hedge Accounting

All derivatives are recognized in the balance sheet as either an asset or liability and are measured at fair value, other than transactions for which normal purchase/normal sale is applied. Certain criteria must be satisfied in order for derivative financial instruments to be designated for hedge accounting. Unrealized gains and losses related to unsettled derivatives that have been designated for hedge accounting treatment are recorded in either earnings or as a component of other comprehensive income until settled. In the period of settlement, the Company recognizes the gains and losses from these qualifying hedges in gas sales revenues. As of September 30, 2017 and 2016, the Company had no positions designated for hedge accounting treatment.

Table of Contents

(7) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

The following tables detail the components of accumulated other comprehensive income (loss) and the related tax effects for the nine months ended September 30, 2017:

	Pension and Other Postretirement (in millions)	Foreign Currency (in millions)	Total
Beginning balance, December 31, 2016	\$ (19)	\$ (20)	\$ (39)
Other comprehensive income before reclassifications	—	—	—
Amounts reclassified from other comprehensive income (1)	2	—	2
Net current-period other comprehensive income	2	—	2
Ending balance, September 30, 2017	\$ (17)	\$ (20)	\$ (37)

(1) See separate table below for details about these reclassifications.

1

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income For the nine months ended September 30, 2017 (in millions)
Pension and other postretirement:		

Amortization of prior service cost and net loss

(1)	General and administrative expenses	\$	2
	Provision for income taxes		–
	Net income (loss)	\$	2

Total reclassifications for the period Net income (loss) \$ 2

(1) See [Note 11](#) for additional details regarding the Company's pension and other postretirement benefit plans.

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of September 30, 2017 and December 31, 2016 were as follows:

	September 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	\$ 989	\$ 989	\$ 1,423	\$ 1,423
2015 term loan due December 2020	–	–	327	327
2016 term loan due December 2020 (1)	1,191	1,191	1,191	1,191
Senior notes	3,282	3,317	3,166	3,182
Derivative instruments, net (2)	(25)	(25)	(375)	(375)

(1) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least \$765 million of its senior notes due in January 2020. As of September 30, 2017, the Company has redeemed \$758 million principal amount outstanding of the 2020 senior notes.

(2) Excludes \$2 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet.

The carrying values of cash and cash equivalents, accounts receivable, other current assets, accounts payable and other current liabilities on the unaudited condensed consolidated balance sheets approximate fair value because of their short-term nature. For debt and derivative instruments, the following methods and assumptions were used to estimate fair value:

Debt: The fair values of the Company's senior notes were based on the market value of the Company's publicly traded debt as determined based on the yield of the Company's senior notes.

The carrying values of the borrowings under the Company's term loan facilities and unsecured revolving credit facility approximate fair value because the interest rate is variable and reflective of market rates. The Company considers the fair value of its debt to be a Level 2 measurement on the fair value hierarchy.

15

Table of Contents

Derivative Instruments: The fair value of all derivative instruments is the amount at which the instrument could be exchanged currently between willing parties. The amounts are based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The fair value hierarchy prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 valuations - Consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.

Level 2 valuations - Consist of quoted market information for the calculation of fair market value.

Level 3 valuations - Consist of internal estimates and have the lowest priority.

The Company has classified its derivatives into these levels depending upon the data utilized to determine their fair values. The Company's fixed price swaps (Level 2) are estimated using third-party discounted cash flow calculations using the NYMEX futures index. The Company utilized discounted cash flow models for valuing its interest rate derivatives (Level 2). The net derivative values attributable to the Company's interest rate derivative contracts as of September 30, 2017 are based on (i) the contracted notional amounts, (ii) active market-quoted London Interbank Offered Rate ("LIBOR") yield curves and (iii) the applicable credit-adjusted risk-free rate yield curve. The Company's call options, purchased put options, two-way costless collars and three-way costless collars (Level 3) are valued using the Black-Scholes model, an industry standard option valuation model that takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the NYMEX futures index, interest rates, volatility and credit worthiness. The Company's basis swaps (Level 3) are estimated using third-party calculations based upon forward commodity price curves.

Inputs to the Black-Scholes model, including the volatility input, which is the significant unobservable input for Level 3 fair value measurements, are obtained from a third-party pricing source, with independent verification of the most significant inputs on a monthly basis. An increase (decrease) in volatility would result in an increase (decrease) in fair value measurement, respectively.

Assets and liabilities measured at fair value on a recurring basis are summarized below (in millions):

	September 30, 2017			
	Fair Value Measurements Using:			
	Quoted			
	Prices			
	in	Significant		
	Active	Other	Significant	Assets
	Market	Observable	Unobservable	(Liabilities)
	(Level	Inputs	Inputs (Level	at Fair
	1)	(Level 2)	3)	Value
	\$ -	\$ 13	\$ -	\$ 13
Fixed price swap assets	\$ -	\$ 13	\$ -	\$ 13
Two-way costless collars assets	-	-	7	7
Three-way costless collars assets	-	-	106	106
Basis swap assets	-	-	19	19
Call option assets (1)	-	-	1	1
Fixed price swap liabilities	-	(16)	-	(16)
Two-way costless collars liabilities	-	-	(7)	(7)
Three-way costless collars liabilities	-	-	(100)	(100)
Basis swap liabilities	-	-	(23)	(23)
Call option liabilities	-	-	(23)	(23)
Interest rate swap liabilities	-	(2)	-	(2)
Total	\$ -	\$ (5)	\$ (20)	\$ (25)

(1) Excludes \$2 million in premiums paid related to certain call options currently recognized as a component of derivative assets within current assets on the unaudited condensed consolidated balance sheet.

Table of Contents

	December 31, 2016			
	Fair Value Measurements Using:			
	Quoted			
	Prices			
	in	Significant		
	Active	Other	Significant	Assets
	Market	Observable	Unobservable	(Liabilities)
	(Level	Inputs	Inputs (Level	at Fair
	1)	(Level 2)	3)	Value
Fixed price swap assets	\$ –	\$ 1	\$ –	\$ 1
Two-way costless collars assets	–	–	10	10
Three-way costless collars assets	–	–	111	111
Basis swap assets	–	–	33	33
Fixed price swap liabilities	–	(178)	–	(178)
Two-way costless collars liabilities	–	–	(58)	(58)
Three-way costless collars liabilities	–	–	(192)	(192)
Basis swap liabilities	–	–	(18)	(18)
Call option liabilities	–	–	(81)	(81)
Interest rate swap liabilities	–	(3)	–	(3)
Total	\$ –	\$ (180)	\$ (195)	\$ (375)

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three and nine months ended September 30, 2017 and 2016. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect reasonable assumptions a marketplace participant would have used as of September 30, 2017 and 2016.

	For the three months ended September 30, 2017		For the nine months ended September 30, 2016	
	(in millions)		(in millions)	
Balance at beginning of period	\$ (52)	\$ (83)	\$ (195)	\$ 3
Total gains (losses):				
Included in earnings	42	58	141	(13)
Settlements	(10)	–	34	(15)
Transfers into/out of Level 3	–	–	–	–
Balance at end of period	\$ (20)	\$ (25)	\$ (20)	\$ (25)
Change in gains (losses) included in earnings relating to derivatives still held as of September 30	\$ 32	\$ 58	\$ 175	\$ (28)

(9) DEBT

The components of debt as of September 30, 2017 and December 31, 2016 consisted of the following:

	September 30, 2017			
	Debt Instrument	Unamortized Issuance Expense	Unamortized Debt Discount	Total
	(in millions)			
Short-term debt:				
7.35% Senior Notes due October 2017 (1)	\$ 15	\$ –	\$ –	\$ 15
7.125% Senior Notes due October 2017 (1)	25	–	–	25
Total short-term debt	\$ 40	\$ –	\$ –	\$ 40
Long-term debt:				
Variable rate (3.700% at September 30, 2017) 2016 term loan, due December 2020 (2)	1,191	(8)	–	1,183
4.05% Senior Notes due January 2020 (3) (4)	92	–	–	92
4.10% Senior Notes due March 2022	1,000	(4)	–	996
4.95% Senior Notes due January 2025 (3)	1,000	(6)	(2)	992
7.50% Senior Notes due April 2026	650	(10)	–	640
7.75% Senior Notes due October 2027	500	(7)	–	493
Total long-term debt	\$ 4,433	\$ (35)	\$ (2)	\$ 4,396

Total debt	\$ 4,473	\$ (35)	\$ (2)	\$ 4,436
------------	----------	---------	--------	----------

17

Table of Contents

	December 31, 2016			
	Debt	Unamortized Issuance	Unamortized Debt	Total
	Instrument	Expense	Discount	
	(in millions)			
Short-term debt:				
7.35% Senior Notes due October 2017 (1)	\$ 15	\$ –	\$ –	\$ 15
7.125% Senior Notes due October 2017 (1)	25	–	–	25
7.15% Senior Notes due June 2018 (4)	1	–	–	1
Total short-term debt	\$ 41	\$ –	\$ –	\$ 41
Long-term debt:				
Variable rate (3.220% at December 31, 2016) 2015 term loan, due December 2020 (4)	327	(2)	–	325
Variable rate (3.220% at December 31, 2016) 2016 term loan, due December 2020 (2)	1,191	(10)	–	1,181
3.30% Senior Notes due January 2018 (3) (4)	38	–	–	38
7.50% Senior Notes due February 2018 (4)	212	–	–	212
7.15% Senior Notes due June 2018 (4)	25	–	–	25
4.05% Senior Notes due January 2020 (3) (4)	850	(5)	–	845
4.10% Senior Notes due March 2022	1,000	(4)	(1)	995
4.95% Senior Notes due January 2025 (3)	1,000	(7)	(2)	991
Total long-term debt	\$ 4,643	\$ (28)	\$ (3)	\$ 4,612
Total debt	\$ 4,684	\$ (28)	\$ (3)	\$ 4,653

- (1) Subsequent to September 30, 2017, the Company repaid \$15 million and \$25 million of its outstanding 7.35% and 7.125% Senior Notes, respectively, due October 2017.
- (2) The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced \$765 million of its outstanding senior notes due in January 2020. As of September 30, 2017, the Company has redeemed \$758 million principal amount of the 2020 senior notes.
- (3) In February and June 2016, Moody's and S&P downgraded certain senior notes, increasing the interest rates by 175 basis points effective July 2016. As a result of the downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes.
- (4) In the first nine months of 2017, the Company repurchased \$38 million principal amount of its outstanding 3.30% Senior Notes due January 2018, \$212 million principal amount of its outstanding 7.50% Senior Notes due February 2018, \$26 million principal amount of its outstanding 7.15% Senior Notes due June 2018, \$327 million principal amount of its outstanding 2015 Term Loan due December 2020 and \$758 million principal amount of its outstanding 4.05% Senior Notes due January 2020. The Company recognized a \$70 million loss on the extinguishment of debt.

Senior Notes

In January 2015, the Company completed a public offering of \$350 million aggregate principal amount of its 3.30% senior notes due 2018 (the “2018 Notes”), \$850 million aggregate principal amount of its 4.05% senior notes due 2020 (the “2020 Notes”) and \$1.0 billion aggregate principal amount of its 4.95% senior notes due 2025 (the “2025 Notes” together with the 2018 and 2020 Notes, the “Notes”), with net proceeds from the offering totaling approximately \$2.2 billion after underwriting discounts and offering expenses. The interest rates on the Notes are determined based upon the public bond ratings from Moody’s and S&P. Downgrades on the Notes from either rating agency increase interest costs by 25 basis points per downgrade level and upgrades decrease interest costs by 25 basis points per upgrade level, up to the stated coupon rate, on the following semi-annual bond interest payment. In February and June 2016, Moody’s and S&P downgraded the Notes, increasing the interest rates by 175 basis points effective July 2016. As a result of these downgrades, interest rates increased to 5.05% for the 2018 Notes, 5.80% for the 2020 Notes and 6.70% for the 2025 Notes. In the event of future downgrades, the coupons for this series of notes are capped at 5.30%, 6.05% and 6.95%, respectively. The first coupon payment at the higher interest rates was paid in January 2017.

During the first half of 2017, the Company redeemed or repurchased (i) \$38 million principal amount of its outstanding 2018 Notes, (ii) \$212 million principal amount of its outstanding 7.50% Senior Notes due February 2018 and (iii) \$26 million principal amount of its outstanding 7.15% Senior Notes due June 2018, and recognized an \$11 million loss on the extinguishment of debt.

In September 2017, the Company completed a public offering of \$650 million aggregate principal amount of its 7.50% senior notes due 2026 (the “2026 Notes”) and \$500 million aggregate principal amount of its 7.75% senior notes due 2027 (the “2027 Notes”), with net proceeds from the offering totaling approximately \$1.1 billion after underwriting discounts and offering expenses. Both series of senior notes were sold to the public at face value. The proceeds from this

Table of Contents

offering were used to purchase \$758 million of the Company's 2020 Notes in a tender offer and to repay the outstanding balance of \$327 million on the Company's 2015 Term Loan. The Company recognized a loss on extinguishment of debt of \$59 million, which included \$53 million of premiums paid.

2016 Credit Facility

In June 2016, the Company reduced its existing \$2.0 billion unsecured revolving credit facility to \$66 million and entered into a new credit agreement for \$1,934 million, consisting of a \$1,191 million secured term loan and a new \$743 million unsecured revolving credit facility, which matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, the Company has not amended, redeemed or refinanced at least \$765 million of its senior notes due January 2020. In September 2017, the Company used a portion of the proceeds from the September 2017 debt offering to settle a tender offer by purchasing an aggregate principal amount of approximately \$758 million of its outstanding senior notes due in January 2020. The \$1,191 million secured term loan is fully drawn, with approximately \$285 million of this balance used to pay down the previous revolving credit facility balance in its entirety. As of September 30, 2017, there were no borrowings under either revolving credit facility; however, \$323 million in letters of credit was outstanding against the 2016 revolving credit facility.

Loans under the 2016 credit agreement are subject to varying rates of interest based on whether the loan is a Eurodollar loan or an alternate base rate loan. Eurodollar loans bear interest at the Eurodollar rate, which is adjusted LIBOR plus applicable margins ranging from 1.750% to 2.500%. Alternate base rate loans bear interest at the alternate base rate plus the applicable margin ranging from 0.750% to 1.500%. The interest rates on the term loan and revolving credit facility are determined based upon the Company's public debt ratings and was 250 basis points over LIBOR as of September 30, 2017.

The 2016 term loan and revolving credit facility contain financial covenants that impose certain restrictions on the Company. In September 2017, the Company amended its 2016 credit agreement to reflect the following:

(i) increase the minimum interest coverage ratio to 2.00x commencing with the fiscal quarter ended June 30, 2017 and continued over the life of the 2016 Credit Agreement;

(ii) modify the minimum liquidity covenant such that either (1) if leverage is less than 4.00x or if the 2016 revolving credit facility has been terminated, there is no minimum liquidity covenant, or (2) the Company can elect to replace the minimum liquidity covenant with a maximum leverage ratio of no more than 5.50x for the fiscal quarters ending September 30, 2017 and December 31, 2017, 5.00x for the fiscal quarters ending March 31, 2018 and June 30, 2018 and 4.50x thereafter; and

(iii) modify the mandatory prepayment and commitment reduction provisions to permit the Company to retain the first \$500.0 million of net cash proceeds from asset sales that would have otherwise been required to prepay amounts outstanding under the 2016 revolving credit facility and/or reduce commitments under the 2016 revolving credit facility.

In September of 2017, substantially all of the proceeds of the 2026 and 2027 notes issuance were applied to repay existing debt.

As of September 30, 2017, the Company has not elected to replace the minimum liquidity covenant with a maximum leverage covenant. Therefore, under the amended credit agreement, should the leverage ratio exceed 4.0x, the Company would be subject to a minimum liquidity requirement of \$300 million. The financial covenant with respect to the maximum leverage ratio consists of total debt divided by EBITDAX. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX, as defined in the Company's 2016 credit agreement, excludes the effects of interest expense, income taxes, depreciation, depletion and amortization, any non-cash impacts from impairments, certain non-cash hedging activities, stock-based compensation expense, non-cash gains or losses on asset sales, unamortized issuance cost, unamortized debt discount and certain restructuring costs. Collateral for the secured term loan is principally the Company's E&P properties in the Fayetteville Shale area, the equity of its subsidiaries and cash and marketable securities on hand, and the credit agreement requires a minimum collateral coverage ratio of 1.50x for the 2016 secured term loan. This collateral also may support all or a part of revolving credit extensions depending on restrictions in the Company's senior notes indentures.

Table of Contents

As of September 30, 2017, the Company was in compliance with all of the covenants of this credit agreement. Although the Company does not anticipate any violations of the financial covenants, its ability to comply with these covenants is dependent upon the success of its exploration and development program and upon factors beyond the Company's control, such as the market prices for natural gas, oil and NGLs.

2013 Credit Facility

In December 2013, the Company entered into a credit agreement that exchanged its previous revolving credit facility. Under this revolving credit facility, the Company originally had a borrowing capacity of \$2.0 billion. The revolving credit facility was unsecured and was not guaranteed by any subsidiaries. In June 2016, this credit facility was substantially exchanged for a new credit facility comprised of a \$1,191 million secured term loan and a new \$743 million revolving credit facility. The borrowing capacity of the original 2013 credit agreement was reduced from \$2.0 billion to \$66 million, remains unsecured and the maturity remains December 2018. As of September 30, 2017, there were no borrowings under this facility.

The existing unsecured 2013 revolving credit facility includes a financial covenant under which the Company may not have total debt in excess of 60% of its total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any full cost ceiling impairments, certain hedging activities and the Company's pension and other postretirement liabilities. At September 30, 2017, debt constituted 32% of the Company's adjusted book capital.

2015 Term Loan

In November 2015, the Company entered into a \$750 million unsecured three-year term loan credit agreement with various lenders that was utilized to repay borrowings under the revolving credit facility. In 2016, the Company repaid \$423 million of the \$750 million unsecured term loan from a portion of the net proceeds of the July 2016 equity offering along with proceeds received from a non-core asset sale. In September 2017, the remaining outstanding balance of \$327 million was repaid, and the 2015 Term Loan was terminated.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of September 30, 2017, the Company's contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately \$8.9 billion, \$3.7 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and additional construction efforts. Southwestern Energy Company also had guarantee obligations of up to \$832 million of that amount. As of September 30, 2017, future payments under non-cancelable firm transportation and gathering agreements were as follows:

	Payments Due by Period					More than 8 Years
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	
	(in millions)					
Infrastructure currently in service	\$ 5,136	\$ 196	\$ 1,105	\$ 524	\$ 1,492	\$ 1,819
Pending regulatory approval and/or construction (1)	3,722	432	458	702	114	2,016
Total transportation charges	\$ 8,858	\$ 628	\$ 1,563	\$ 1,226	\$ 1,606	\$ 3,835

(1) Based on the estimated in-service dates as of September 30, 2017.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on the financial position or results of operations of the Company.

Litigation

The Company is subject to various litigation, claims and proceedings that have arisen in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic accidents and

Table of Contents

pollution, contamination or nuisance. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on the Company's financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on the Company's results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future.

Arkansas Royalty Litigation

In June 2017, the jury returned a verdict in favor of the Company on all counts in *Smith v. SEECO, Inc. et al.*, a class action in the United States District Court for the Eastern District of Arkansas. The plaintiff had alleged that the Company had underpaid lessors of lands in Arkansas by deducting from royalty payments costs for gathering, transportation and compression of natural gas in excess of what is permitted by the relevant leases and asserted claims for, among other things, breach of contract, fraud, civil conspiracy, unjust enrichment and violation of certain Arkansas statutes. Following the verdict, the court entered judgment in favor of the Company on all claims. The plaintiff has moved for a new trial, and the court has not yet ruled on that motion.

The plaintiff class in *Smith* comprises the vast majority of lessors of lands in Arkansas for which leases permit deductions for these types of costs. Most of the remaining lessors are named plaintiffs or members of classes in other pending lawsuits. In particular, two actions on behalf of certified classes of only Arkansas residents pending in state courts in Arkansas (one is set for trial during the third quarter of 2018; the other does not have a trial date) and three cases (all currently stayed) that were filed in Arkansas state court on behalf of a total of 248 individually named plaintiffs, two of which have been removed to federal court, have been assigned to the same court that held the *Smith* trial. Management believes that, as the *Smith* jury concluded, the deductions from royalty payments were calculated in accordance with the leases. The Company currently does not anticipate that these other cases are likely to have a material adverse effect on the results of operations, financial position or cash flows of the Company.

Indemnifications

The Company provides certain indemnifications in relation to dispositions of assets. These indemnifications typically relate to disputes, litigation or tax matters existing at the date of disposition. No material liabilities have been recognized in connection with these indemnifications.

(11) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company maintains defined pension and postretirement benefit plans, which cover substantially all of the Company's employees. Net periodic pension costs include the following components for the three and nine months ended September 30, 2017 and 2016:

	Pension Benefits			
	For the three months ended September 30, 2017		For the nine months ended September 30, 2016	
	2017	2016	2017	2016
	(in millions)			
Service cost	\$ 2	\$ 3	\$ 7	\$ 9
Interest cost	2	1	4	4
Expected return on plan assets	(1)	(2)	(4)	(5)
Amortization of prior service cost	—	—	—	—
Amortization of net loss	—	—	1	1
Curtailment loss	—	—	—	1
Settlement loss	—	2	—	10
Net periodic benefit cost	\$ 3	\$ 4	\$ 8	\$ 20

The Company's other postretirement benefit plan had a net periodic benefit cost of \$1 million for the three months ended September 30, 2017 and 2016 and a net periodic benefit cost (gain) of \$2 million and (\$4) million for the nine months ended September 30, 2017 and 2016, respectively. Included in the net periodic benefit cost for the nine months ended September 30, 2016 is a curtailment gain of \$6 million, which more than offset the other components of net periodic benefit cost.

Table of Contents

As of September 30, 2017, the Company has contributed \$11 million to the pension and other postretirement benefit plans in 2017. The Company expects to contribute an additional \$3 million to its pension plan during the remainder of 2017. The Company recognized a liability of \$32 million and \$14 million related to its pension and other postretirement benefits, respectively, as of September 30, 2017, compared to a liability of \$36 million and \$13 million as of December 31, 2016. The Company updated the discount rate currently used in the measurement of the benefit obligation of the pension plan and other postretirement benefits plan to 4.20% in the second quarter of 2016. The Company used a discount rate of 4.60% during the first quarter of 2016 for the measurement of the benefit obligation of both the pension and other postretirement benefit plans. In January 2016, the Company initiated a reduction in workforce that was substantially completed by the end of the first quarter of 2016. The impact of the workforce reduction on the Company's pension and other postretirement benefit costs was not recognized until subsequent quarters in 2016 due to the delayed timing of actuarial data available.

The Company maintains a non-qualified deferred compensation supplemental retirement savings plan ("Non-Qualified Plan") for certain key employees who may elect to defer and contribute a portion of their compensation, as permitted by the Non-Qualified Plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock and totaled 10,652 shares at September 30, 2017, compared to 31,269 shares at December 31, 2016.

(12) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and nine months ended September 30, 2017 and 2016:

	For the three months ended September 30, 2017		For the nine months ended September 30, 2016	
	2017	2016	2017	2016
	(in millions)			
Stock-based compensation cost – expensed (1)	\$ 7	\$ 6	\$ 19	\$ 43
Stock-based compensation cost – capitalized	\$ 2	\$ 2	\$ 10	\$ 7

(1) Includes \$16 million and \$3 million related to the reduction in workforce and executive management restructuring, respectively, for the nine months ended September 30, 2016.

In January 2016, the Company announced a 40% workforce reduction that was substantially completed by the end of March 2016. In April 2016, the Company also partially restructured executive management, which was substantially completed in the second quarter of 2016. Affected employees were offered a severance package that included, if

applicable, amendments to certain outstanding equity awards that modified forfeiture provisions on separation from the Company. As a result, certain unvested stock-based equity awards became fully vested at the time of separation. These shares were revalued and recognized immediately as a component of restructuring charges on the Company's unaudited condensed consolidated statements of operations. The unvested portion of equity-based performance units was forfeited upon separation from the Company.

As of September 30, 2017, there was \$67 million of total unrecognized compensation cost related to the Company's unvested stock option grants, restricted stock grants and performance units. This cost is expected to be recognized over a weighted-average period of 3 years.

Stock Options

The following table summarizes stock option activity for the nine months ended September 30, 2017 and provides information for options outstanding and options exercisable as of September 30, 2017:

	Number of Options (in thousands)	Weighted Average Exercise Price (per share)
Outstanding at December 31, 2016	5,416	\$ 23.46
Granted	1,604	8.00
Exercised	—	—
Forfeited or expired	(725)	17.92
Outstanding at September 30, 2017	6,295	20.16
Exercisable at September 30, 2017	3,336	\$ 29.37

Table of Contents

Restricted Stock

The following table summarizes restricted stock activity for the nine months ended September 30, 2017 and provides information for unvested shares as of September 30, 2017:

	Number of Shares (in thousands)	Weighted Average Fair Value (per share)
Unvested shares at December 31, 2016	3,321	\$ 11.85
Granted	5,036	8.39
Vested	(247)	9.40
Forfeited	(609)	10.16
Unvested shares at September 30, 2017	7,501	\$ 9.68

Equity-Classified Performance Units

The following table summarizes performance unit activity for the nine months ended September 30, 2017 and provides information for unvested units as of September 30, 2017. The performance units awarded in 2014 included a market condition based on relative Total Shareholder Return (“TSR”) and a performance condition based on the Company's Present Value Index (“PVI”), collectively the “Performance Measures.” The fair value of the TSR market condition is based on a Monte Carlo model and the fair value of the PVI performance condition is based on economic analysis for each investment opportunity based upon the expected present value added for each dollar to be invested. The total fair value of the performance units is amortized to compensation expense on a straight line basis over the vesting period of the award. The performance unit awards granted in 2015, 2016 and during the first nine months of 2017 include a market condition based exclusively on TSR. The grant date fair value is calculated using the applicable Performance Measures and the closing price of the Company’s common stock at the grant date.

	Number of Units (1) (in thousands)	Weighted Average Fair Value (per share)
Unvested units at December 31, 2016	719	\$ 11.46
Granted	1,197	10.47

Vested	(42)	5.94
Forfeited	(472)	9.74
Unvested units at September 30, 2017	1,402	\$ 10.78

(1) These amounts reflect the number of performance units granted in thousands. The actual payout of shares may range from a minimum of zero shares to a maximum of two shares per unit contingent upon the actual performance against the Performance Measures. The performance units have a three-year vesting term and the actual disbursement of shares, if any, is determined during the first quarter following the end of the three-year vesting period.

Liability-Classified Performance Units

Prior to 2013, certain employees were awarded performance units which vested equally over three years and which were settled in cash. The payout of these units was based on certain metrics, such as total shareholder return and reserve replacement efficiency, compared to a predetermined group of peer companies and Company goals. At the end of each performance period, the value of the vested performance units, if any, would be paid in cash. In the first quarter of 2016, the Company completed the final payout with respect to these performance units.

(13) SEGMENT INFORMATION

The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and liquids. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced natural gas and liquids volumes and through gathering fees associated with the transportation of natural gas to market.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the 2016 Annual Report. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs. Income before income taxes, for the purpose of reconciling the operating income amount shown below to consolidated income before income taxes, is the sum of operating income, interest expense, gain (loss) on derivatives, loss on early extinguishment of debt and other income (loss). The "Other" column includes items not related to the Company's reportable segments, including real estate and corporate items.

Table of Contents

	Exploration and Production (in millions)	Midstream Services	Other	Total
Three months ended September 30, 2017:				
Revenues from external customers	\$ 475	\$ 262	\$ –	\$ 737
Intersegment revenues	(5)	472	–	467
Depreciation, depletion and amortization expense	120	15	–	135
Operating income	64	46	–	110
Interest expense (1)	31	–	–	31
Gain on derivatives	45	–	–	45
Loss on early extinguishment of debt	–	–	(59)	(59)
Other income (loss), net	1	(3)	–	(2)
Benefit for income taxes (1)	(14)	–	–	(14)
Assets	4,842	1,240	1,120 (2)	7,202
Capital investments (3)	320	9	2	331
Three months ended September 30, 2016:				
Revenues from external customers	\$ 381	\$ 270	\$ –	\$ 651
Intersegment revenues	(3)	412	–	409
Depreciation, depletion and amortization expense	83	16	–	99
Impairment of natural gas and oil properties	817	–	–	817
Operating income (loss)	(777) (4)	52	–	(725)
Interest expense (1)	26	–	–	26
Gain on derivatives	71	–	–	71
Loss on early extinguishment of debt	–	–	(51)	(51)
Other income, net	2	1	–	3
Benefit for income taxes (1)	(20)	–	–	(20)
Assets	4,015	1,253	1,622 (2)	6,890
Capital investments (3)	179	1	–	180

	Exploration and Production (in millions)	Midstream Services	Other	Total
Nine months ended September 30, 2017:				
Revenues from external customers	\$ 1,572	\$ 822	\$ –	\$ 2,394

Edgar Filing: SOUTHWESTERN ENERGY CO - Form 10-Q

Intersegment revenues	(13)	1,592	–	1,579
Depreciation, depletion and amortization expense	317	47	–	364
Operating income	435	129	–	564
Interest expense (1)	97	–	–	97
Gain on derivatives	295	–	–	295
Loss on early extinguishment of debt	–	–	(70)	(70)
Other income, net	5	1	–	6
Benefit for income taxes(1)	(14)	–	–	(14)
Assets	4,842	1,240	1,120 (2)	7,202
Capital investments (3)	921	21	4	946

Nine months ended September 30, 2016:

Revenues from external customers	\$ 1,015	\$ 737	\$ –	\$ 1,752
Intersegment revenues	(17)	1,125	–	1,108
Depreciation, depletion and amortization expense	300	49	–	349
Impairment of natural gas and oil properties	2,321	–	–	2,321
Operating income (loss)	(2,486)(4)	169	(5)	(2,317)
Interest expense (1)	56	1	–	57
Loss on derivatives	(27)	(1)	–	(28)
Loss on early extinguishment of debt	–	–	(51)	(51)
Other income (loss), net	3	(2)	(1)	–
Benefit for income taxes	(20)	–	–	(20)
Assets	4,015	1,253	1,622 (2)	6,890
Capital investments (3)	372	3	1	376

(1) Interest expense and the benefit for income taxes by segment are an allocation of corporate amounts as they are incurred at the corporate level.

(2) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At September 30, 2017 and 2016, other assets includes approximately \$989 million and \$1.5 billion in cash and cash equivalents, respectively.

Table of Contents

- (3) Capital investments includes a decrease of \$2 million and an increase of \$27 million for the three months ended September 30, 2017 and 2016, respectively, and decreases of \$13 million and \$24 million for the nine months ended September 30, 2017 and 2016, respectively, relating to the change in capital accruals between periods.
- (4) Operating income (loss) for the E&P segment includes \$2 million and \$74 million related to restructuring charges for the three and nine months ended September 30, 2016, respectively.
- (5) Operating income (loss) for the Midstream services segment includes \$3 million related to restructuring charges for the nine months ended September 30, 2016.

Included in intersegment revenues of the Midstream Services segment are \$422 million and \$355 million for the three months ended September 30, 2017 and 2016, respectively and \$1,436 million and \$941 million for the nine months ended September 30, 2017 and 2016, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments.

(14) INCOME TAXES

The Company's effective tax rate was approximately (21%) and (2%) for the three and nine months ended September 30, 2017, respectively, and 3% and 1% for the same periods in 2016, respectively. The income tax benefits recognized in the third quarter of 2017 resulted from an expected alternative minimum tax refund along with the expiration of a portion of the Company's uncertain tax provision. The low effective tax rates are primarily a result of the existence of a valuation allowance. 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 assets will not be realized. To assess that likelihood, the Company uses estimates and judgment regarding future taxable income, and considers the tax consequences in the jurisdiction where such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include current financial position, 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 the oil and gas industry.

The Company maintained its net deferred tax asset position at September 30, 2017 primarily due to the write-downs of the carrying value of natural gas and oil properties in 2015 and 2016. The Company recorded decreases in our valuation allowance of \$38 million and \$220 million for the three and nine months ended September 30, 2017, respectively. For the three and nine months ended September 30, 2016, there were increases in our valuation allowance of \$256 million and \$903 million, respectively. 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. In management's view, the cumulative loss incurred over recent years outweighs any positive factors, such as the possibility of future growth. The amount of the deferred tax assets 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.

(15) NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Standards Implemented

In March 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2016-09, Compensation – Stock Compensation (Topic 718) (“Update 2016-09”), to simplify accounting for share-based payment transactions including income tax consequences, classification of awards as either equity or liabilities, and the classification on the statement of cash flows. For public entities, Update 2016-09 became effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company adopted Update 2016-09 during the first quarter with an effective date of January 1, 2017. The recognition of previously unrecognized windfall tax benefits resulted in a net cumulative-effect adjustment of \$59 million, which increased net deferred tax assets and the related income tax valuation allowance by the same amount as of the beginning of 2017. The amendments within Update 2016-09 related to the recognition of excess tax benefits and tax shortfalls in the income statement and presentation within the operating section of the statement of cash flows were adopted prospectively, with no adjustments made to prior periods. The Company has elected to account for forfeitures as they occur. The remaining provisions of this amendment did not have a material effect on its unaudited condensed consolidated results of operations, financial position or cash flows.

Table of Contents

New Accounting Standards Not Yet Implemented

In August 2017, the FASB issued Accounting Standards Update (ASU) No. 2017-12, Derivatives and Hedging (Topic 815) (“Update 2017-12”), which makes significant changes to the current hedge accounting rules. The new guidance impacts the designation of hedging relationships; measurement of hedging relationships; presentation of the effects of hedging relationships; assessment of hedge effectiveness; and disclosures. The guidance is effective for annual periods beginning after December 15, 2018, including interim periods within those annual periods. The Company is evaluating the impact of the adoption of Update 2017-12 on its consolidated financial statements and related disclosures.

In March 2017, the FASB issued Accounting Standards Update No. 2017-07, Compensation - Retirement Benefits (Topic 715) (“Update 2017-07”), which provides additional guidance on the presentation of net benefit cost in the statement of operations and on the components eligible for capitalization in assets. The guidance requires employers to disaggregate the service cost component from the other components of net benefit cost. The service cost component of the net periodic benefit cost shall be reported in the same line item as other compensation costs arising from services rendered by the employees during the period, except for amounts capitalized. All other components of net benefit cost shall be presented outside of a subtotal for income from operations. The guidance is effective for annual periods beginning after December 15, 2017, including interim periods within those annual periods. The amendments in this update should be applied retrospectively for the presentation of the service cost component and the other components of net periodic postretirement benefit cost in the income statement and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic benefit cost in assets. The Company does not expect the impact of adopting Update 2017-07 to have a material effect on its consolidated financial statements and related disclosures.

In August 2016, the FASB issued Accounting Standards Update No. 2016-15, Statement of Cash Flows (Topic 230) (“Update 2016-15”), which seeks to reduce the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. For public entities, Update 2016-15 becomes effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The Company does not expect the impact of adopting Update 2016-15 to have a material effect on its consolidated financial statements and related disclosures.

In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases (Topic 842) (“Update 2016-02”), which seeks to increase transparency and comparability among organizations by, among other things, recognizing lease assets and lease liabilities on the balance sheet for leases classified as operating leases under previous GAAP and disclosing key information about leasing arrangements. Through September 2017, the Company made progress on contract reviews, drafting its accounting policies, evaluating lease accounting software and assessing the new disclosure requirements. The Company will continue assessing the effect that the updated standard may have on its consolidated financial statements and related disclosures, and anticipates that its assessment will be complete in 2018. For public entities, Update 2016-02 becomes effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted.

In May 2014, the FASB issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (“Update 2014-09”), which seeks to provide clarity for recognizing revenue. The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The Company performed an analysis, across all revenue streams, of the impact of Update 2014-09 and the related ASUs and did not, to date, identify any changes to its revenue recognition policies that would result in a material adjustment to its consolidated financial statements and related disclosures. The Company will continue to conduct its contract review process throughout 2017 and, as a result, additional areas of impact may be identified. The Company expects to adopt the new standard using the modified retrospective approach, under which the cumulative effect of initially applying the new guidance is recognized as an adjustment to the opening balance of retained earnings in the first quarter of 2018. For public entities, the new standard is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period.

Table of Contents

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following updates information as to Southwestern Energy Company's financial condition provided in our 2016 Annual Report on Form 10-K and analyzes the changes in the results of operations between the three and nine months ended September 30, 2017 and 2016. For definitions of commonly used natural gas and oil terms used in this Quarterly Report, please refer to the "Glossary of Certain Industry Terms" provided in our 2016 Annual Report.

The following discussion contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in "Cautionary Statement About Forward-Looking Statements" in the forepart of this Quarterly Report, in Item 1A, "Risk Factors" in Part I and elsewhere in our 2016 Annual Report, and Item 1A, "Risk Factors" in Part II in this Quarterly Report and any other quarterly report on Form 10-Q filed during the fiscal year. You should read the following discussion with our unaudited condensed consolidated financial statements and the related notes included in this Quarterly Report.

OVERVIEW

Background

Southwestern Energy Company (including its subsidiaries, collectively, "we", "our", "us", "the Company" or "Southwestern") an independent energy company engaged in natural gas, oil and NGL exploration, development and production, which we refer to as "E&P." We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as "Midstream Services." We conduct most of our businesses through subsidiaries, and we currently operate exclusively in the United States.

Exploration and Production. Our primary business is the exploration for and production of natural gas, oil and NGLs, with our current operations principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. Our operations in northeast Pennsylvania, which we refer to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Our operations in West Virginia and southwest Pennsylvania, which we refer to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. We have smaller holdings in Colorado and Louisiana, along with other areas in which we are testing potential new resources. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas, and we provide certain oilfield products and services, principally serving our E&P operations.

Midstream Services. Through our affiliated midstream subsidiaries, we engage in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support our E&P operations and generate revenue from fees associated with the gathering of natural gas. Our marketing activities capture opportunities that arise through the marketing and transportation of natural gas, oil and NGLs produced in our E&P operations.

Significant third quarter 2017 highlights include:

- Net income attributable to common stock of \$43 million, or \$0.09 per diluted share, improved substantially from a net loss attributable to common stock of \$735 million, or (\$1.52) per diluted share, in the same period in 2016.
- Net cash provided by operating activities of \$211 million was up 23% from \$172 million in the same period in 2016.
- Total net production of 232 Bcfe was up 10% from 211 Bcfe for the same period in 2016.
- We extended the maturities on our debt by issuing \$650 million of Senior Notes due 2026 and \$500 million of Senior Notes due 2027 and using the proceeds of approximately \$1.1 billion to repurchase \$758 million of our 2020 Senior Notes and to repay the outstanding balance of \$327 million on our 2015 Term Loan.

Table of Contents

RESULTS OF OPERATIONS

The following discussion of our results of operations for our segments is presented before intersegment eliminations. We evaluate our segments as if they were stand-alone operations and accordingly discuss their results prior to any intersegment eliminations. Interest expense and income tax expense are discussed on a consolidated basis.

Exploration and Production

(in millions except percentages)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Revenues	\$ 470	\$ 378	\$ 1,559	\$ 998
Impairment of natural gas and oil properties	\$ –	\$ 817	\$ –	\$ 2,321
Operating costs and expenses (1)	\$ 406	\$ 338	\$ 1,124	\$ 1,163
Operating income (loss)	\$ 64	\$ (777)	\$ 435	\$ (2,486)
Gain (loss) on derivatives, settled (2)	\$ 17	\$ (9)	\$ (52)	\$ 22

(1) Includes \$2 million and \$74 million of restructuring charges for the three and nine months ended September 30, 2016, respectively.

(2) Represents the gain (loss) on settled commodity derivatives.

Operating Income

- E&P segment operating income for the three and nine months ended September 30, 2016 includes impairments of natural gas and oil properties of \$817 million and \$2.3 billion, respectively. Excluding the 2016 impairment, our E&P segment operating income increased \$24 million for the three months ended September 30, 2017, compared to the same period in 2016, primarily due to a \$92 million increase in revenues partially offset by a \$68 million increase in operating costs.
- Excluding the 2016 impairment, our E&P segment operating income increased \$600 million for the nine months ended September 30, 2017, compared to the same period in 2016, due to a \$561 million increase in revenues and a \$39 million decrease in operating costs.

Revenues

(in millions except percentages)	Three Months Ended September 30			
	Natural			
	Gas	Oil	NGLs	Total
2016 sales revenues	\$ 337	\$ 19	\$ 22	\$ 378
Changes associated with prices	24	3	28	55
Changes associated with production volumes	27	5	5	37
2017 sales revenues	\$ 388	\$ 27	\$ 55	\$ 470
Increase from 2016	15%	42%	150%	24%

(in millions except percentages)	Nine Months Ended September 30			
	Natural			
	Gas	Oil	NGLs	Total
2016 sales revenues	\$ 890	\$ 49	\$ 59	\$ 998
Changes associated with prices	492	23	70	585
Changes associated with production volumes	(28)	1	3	(24)
2017 sales revenues	\$ 1,354	\$ 73	\$ 132	\$ 1,559
Increase from 2016	52%	49%	124%	56%

The tables above illustrate the effects of the increase in commodity prices and changes associated with production volumes.

Table of Contents

Production Volumes

	For the three months ended September 30,			For the nine months ended September 30,		
	2017	2016	Increase/ (Decrease)	2017	2016	Increase/ (Decrease)
Production volumes:						
Natural Gas (Bcf)						
Northeast Appalachia	101	84	20%	285	268	6%
Southwest Appalachia	25	15	67%	60	48	25%
Fayetteville Shale	78	90	(13%)	241	289	(17%)
Other	1	–	100%	1	–	100%
Total	205	189	8%	587	605	(3%)
Oil (MBbls)						
Southwest Appalachia	639	503	27%	1,673	1,610	4%
Other	24	33	(27%)	74	119	(38%)
Total	663	536	24%	1,747	1,729	1%
NGL (MBbls)						
Southwest Appalachia	3,799	3,053	24%	10,098	9,536	6%
Other	11	15	(27%)	36	44	(18%)
Total	3,810	3,068	24%	10,134	9,580	6%
Production volumes by area (Bcfe):						
Northeast Appalachia	101	84	20%	285	268	6%
Southwest Appalachia	52	37	41%	131	115	14%
Fayetteville Shale	78	90	(13%)	241	289	(17%)
Other	1	–	100%	1	1	–%
Total	232	211	10%	658	673	(2%)

- Production volumes for our E&P segment increased by 21 Bcfe for the three months ended September 30, 2017, compared to the same period in 2016, as increased production volumes from Northeast and Southwest Appalachia more than offset a natural gas production volume decline in the Fayetteville Shale.
- E&P segment production volumes decreased 15 Bcfe for the nine months ended September 30, 2017, compared to the same period in 2016, as a natural gas production volume decline in the Fayetteville Shale more than offset increased production volumes from Northeast and Southwest Appalachia.

Commodity Prices

The price we expect to receive for our production is a critical factor in determining the capital investments we make to develop our properties. Commodity prices fluctuate due to a variety of factors we cannot control or predict, including increased supplies of natural gas, oil or NGLs due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources. These factors impact supply and demand, which in turn determine the sales prices for our production. In addition to these factors, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. We will continue to evaluate the commodity price environments and adjust the pace of our activity to invest within cash flows in order to maintain appropriate liquidity and financial flexibility.

	For the three months ended September 30,			For the nine months ended September 30,		
	2017	2016	Increase/ (Decrease)	2017	2016	Increase/ (Decrease)
Average realized price per unit:						
Natural gas sales, excluding derivatives (per Mcf)	\$ 1.89	\$ 1.78	6%	\$ 2.31	\$ 1.47	57%
Effect of settled gain (loss) on derivatives (per Mcf)	0.08	(0.05)	260%	(0.09)	0.04	(325%)
Natural gas sales, including derivatives (per Mcf)	\$ 1.97	\$ 1.73	14%	\$ 2.22	\$ 1.51	47%
Oil sales (per Bbl)	\$ 40.49	\$ 35.41	14%	\$ 41.48	\$ 28.53	45%
NGL sales, excluding derivatives (per Bbl)	\$ 14.45	\$ 7.03	106%	\$ 13.04	\$ 6.11	113%
Effect of settled gain (loss) on derivatives (per Bbl)	0.02	0.01	100%	0.02	–	100%
NGL sales, including derivatives (per Bbl)	\$ 14.47	\$ 7.04	106%	\$ 13.06	\$ 6.11	114%

- The average price realized for our natural gas production, including the effect of derivatives, increased for the three months ended September 30, 2017, compared to the same period in 2016, due to an \$0.11 per Mcf increase in the average realized price, excluding derivatives, and a \$0.13 per Mcf increase associated with our settled derivatives.

Table of Contents

- Our average price realized for natural gas production, including the effect of derivatives, increased significantly for the nine months ended September 30, 2017, compared to the same period in 2016, due to an \$0.84 per Mcf increase in the average realized price, excluding derivatives, partially offset by a \$0.13 per Mcf decrease associated with our settled derivatives.
- The average price realized for our crude oil production increased by \$5.08 per Bbl and \$12.95 per Bbl for the three and nine months ended September 30, 2017, compared to the same periods in 2016, respectively. We did not use derivatives to financially protect our 2017 or 2016 oil production.
- Our average price realized for NGL production, including the effect of derivatives, increased by \$7.43 per Bbl and \$6.95 per Bbl for the three and nine months ended September 30, 2017, compared to the same periods in 2016, respectively.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices based on heating content of the gas, locational basis differentials, transportation and fuel charges. Additionally, we receive a sales price for our oil and NGLs at a difference to average monthly West Texas Intermediate settlement and Mont Belvieu NGL composite prices, respectively, due to a number of factors including product quality, composition and types of NGLs sold, locational basis differentials, transportation and fuel charges.

- Excluding the impact of derivatives, the average price received for our natural gas production for the nine months ended September 30, 2017 of \$2.31 per Mcf was approximately \$0.86 per Mcf lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation charges. In comparison, the average price received for our natural gas production for the same period in 2016 of \$1.47 per Mcf was approximately \$0.82 per Mcf lower than the average monthly NYMEX settlement price.

We regularly enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas production in order to ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials. We refer you to [Item 3, "Quantitative and Qualitative Disclosures About Market Risks"](#) and [Note 6](#) to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion about our derivatives and risk management activities.

- As of September 30, 2017, we have physically protected basis on approximately 72 Bcf and 145 Bcf of our remaining 2017 and 2018 expected natural gas production, respectively, through physical sales arrangements at a basis differential to NYMEX natural gas price of approximately (\$0.47) per MMBtu and (\$0.36) per MMBtu for the remainder of 2017 and 2018, respectively.
- We have also financially protected basis on approximately 32 Bcf and 25 Bcf of our remaining 2017 and 2018 expected natural gas production, respectively, at a basis differential to NYMEX natural gas price of approximately (\$0.95) per MMBtu and (\$0.63) per MMBtu for the remainder of 2017 and 2018, respectively.

- As of September 30, 2017 we have also financially protected 138 Bcf of our remaining 2017 natural gas production to limit our exposure to NYMEX price fluctuations.

We refer you to Note 6 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our derivative instruments.

30

Table of Contents

Operating Costs and Expenses

(in millions except percentages)	For the three months ended September 30,			For the nine months ended September 30,		
	2017	2016	Increase/ (Decrease)	2017	2016	Increase/ (Decrease)
Lease operating expenses	\$ 210	\$ 181	16%	\$ 591	\$ 586	1%
General & administrative expenses	54	50	8%	147	141	4%
Taxes, other than income taxes	22	22	–%	69	62	11%
Restructuring Charges	–	2	(100%)	–	74	(100%)
Full cost pool amortization	111	73	52%	291	268	9%
Non-full cost pool DD&A	9	10	(10%)	26	32	(19%)
Total operating costs	\$ 406	\$ 338	20%	\$ 1,124	\$ 1,163	(3%)

Average unit costs per Mcfe:	For the three months ended September 30,			For the nine months ended September 30,		
	2017	2016	Increase/ (Decrease)	2017	2016	Increase/ (Decrease)
Lease operating expenses	\$ 0.91	\$ 0.86	6%	\$ 0.90	\$ 0.87	3%
General & administrative expenses (1)	\$ 0.23	\$ 0.23	–%	\$ 0.22	\$ 0.21	5%
Taxes, other than income taxes (2)	\$ 0.10	\$ 0.10	–%	\$ 0.10	\$ 0.09	11%
Full cost pool amortization	\$ 0.48	\$ 0.35	37%	\$ 0.44	\$ 0.40	10%

(1) Excludes \$2 million and \$71 million of restructuring charges for the three and nine months ended September 30, 2016, respectively.

(2) Excludes \$3 million of restructuring charges for the nine months ended September 30, 2016.

Lease Operating Expenses

- Lease operating expenses per Mcfe increased \$0.05 for the three months ended September 30, 2017, compared to the same period of 2016, primarily due to increased salt water disposal costs and increased gas processing costs as our production growth shifts toward the Appalachian basin.
- Lease operating expenses per Mcfe increased \$0.03 for the nine months ended September 30, 2017, compared to the same period of 2016, primarily due to the impact of increased prices for natural gas used as compressor fuel.

General and Administrative Expenses

- General and administrative expenses per Mcfe remained flat for the three months ended September 30, 2017 and 2016 as the \$4 million increase was offset by a 10% increase in production volumes. For the nine months ended September 30, 2017, general and administrative expenses per Mcfe increased 5% compared to the same period from the prior year primarily due to increased professional fees and legal settlements.

Taxes, Other than Income Taxes

- Taxes other than income taxes per Mcfe vary from period to period due to changes in ad valorem and severance taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Full Cost Pool Amortization

- Our full cost pool amortization rate increased \$0.13 per Mcfe and \$0.04 per Mcfe for the three and nine months ended September 30, 2017, respectively, as compared to the same periods in 2016. The increase in the average amortization rate resulted primarily from the addition of future development costs associated with proved undeveloped reserves recognized as a result of improved commodity prices.

The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling impairments, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.

Table of Contents

- Unevaluated costs excluded from amortization were \$1.9 billion at September 30, 2017, compared to \$2.1 billion at December 31, 2016. The unevaluated costs excluded from amortization decreased as the evaluation of previously unevaluated properties totaling \$491 million in the first nine months of 2017 was only partially offset by the impact of \$297 million of unevaluated capital invested during the same period.

Midstream Services

(in millions except percentages)	For the three months ended September 30,			For the nine months ended September 30,		
	2017	2016	Increase/ (Decrease)	2017	2016	Increase/ (Decrease)
Marketing revenues	\$ 656	\$ 591	11%	\$ 2,173	\$ 1,571	38%
Gas gathering revenues	\$ 78	\$ 91	(14%)	\$ 241	\$ 291	(17%)
Marketing purchases	\$ 645	\$ 578	12%	\$ 2,141	\$ 1,533	40%
Operating costs and expenses (1)	\$ 43	\$ 52	(17%)	\$ 144	\$ 160	(10%)
Operating income	\$ 46	\$ 52	(12%)	\$ 129	\$ 169	(24%)
Volumes marketed (Bcfe)	273	264	3%	782	814	(4%)
Volumes gathered (Bcf)	123	145	(15%)	380	463	(18%)

- (1) Includes \$3 million of restructuring charges for the nine months ended September 30, 2016.

Operating Income

- Operating income from our Midstream Services segment decreased \$6 million for the three months ended September 30, 2017, compared to the same period in 2016, primarily due to a \$13 million decrease in gas gathering revenues and a \$2 million decrease in marketing margin, partially offset by a \$9 million decrease in operating costs and expenses.
- Operating income decreased \$40 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a \$50 million decrease in gas gathering revenues and a \$6 million decrease in marketing margin, partially offset by a \$16 million decrease in operating costs and expenses.

- The margin generated from marketing activities was \$11 million and \$13 million for the three months ended September 30, 2017 and 2016, respectively, and \$32 million and \$38 million for the nine months ended September 30, 2017 and 2016, respectively.

Margins are driven primarily by volumes marketed and may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. We enter into derivative contracts from time to time with respect to our natural gas marketing activities to provide margin protection. For more information about our derivatives and risk management activities, we refer you to Item 3, "Quantitative and Qualitative Disclosures About Market Risks" included in this Quarterly Report for additional information.

Revenues

- Revenues from our marketing activities increased \$65 million for the three months ended September 30, 2017, compared to the same period in 2016, primarily due to a 7% increase in the price received for volumes marketed and a 9 Bcfe increase in the volumes marketed.
- For the nine months ended September 30, 2017, revenues from our marketing activities increased \$602 million, compared to the same period in 2016, as a 44% increase in the price received for volumes marketed more than offset a 32 Bcfe decrease in volumes marketed.
- Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in marketing purchase expenses.
- Of the total natural gas volumes marketed, production from our affiliated E&P operated wells accounted for 97% and 91% of the natural gas marketed volumes for the three months ended September 30, 2017 and 2016, respectively, and 96% and 94% of the natural gas marketed volumes for the nine months ended September 30, 2017 and 2016, respectively.

Table of Contents

- Our Midstream Services segment marketed approximately 61% and 63% of our combined oil and NGL production for the three months ended September 30, 2017 and 2016, respectively, and 63% and 65% of our combined oil and NGL production for the nine months ended September 30, 2017 and 2016, respectively.
- Revenues from our gathering activities decreased \$13 million and \$50 million for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to the decreased volumes in the Fayetteville Shale.

Operating Costs and Expenses

- The decrease in operating costs and expenses for the three and nine months ended September 30, 2017 primarily resulted from reduced compression and personnel costs due to lower activity levels as a result of decreased volumes gathered in the Fayetteville Shale.

Restructuring Charges

In January 2016, we announced a 40% workforce reduction, which was substantially concluded by the end of March 2016. In April 2016, we also partially restructured executive management. Affected employees were offered a severance package that included a one-time cash payment depending on length of service and, if applicable, accelerated vesting of outstanding stock-based equity awards. As a result of the workforce reduction and executive management restructuring, we recognized restructuring charges of \$2 million and \$77 million for the three and nine months ended September 30, 2016, respectively.

Interest Expense

(in millions except percentages)	For the three months ended			For the nine months ended		
	September 30, 2017	September 30, 2016	Increase/ (Decrease)	September 30, 2017	September 30, 2016	Increase/ (Decrease)
Gross interest expense	\$ 60	\$ 67	(10%)	\$ 182	\$ 180	1%
Less: capitalization	(29)	(41)	(29%)	(85)	(123)	(31%)
Net interest expense	\$ 31	\$ 26	19%	\$ 97	\$ 57	70%

- The decrease in gross interest expense for the three months ended September 30, 2017, as compared to the same period in 2016, was primarily due to a decrease in our outstanding debt. The increase in gross interest expense for the nine months ended September 30, 2017, as compared to the same period in 2016, was primarily due to an increase in our cost of debt.
- The decrease in capitalized interest for the three and nine months ended September 30, 2017, compared to the same periods in 2016, was primarily due to the evaluation of a portion of our Southwest Appalachia assets.

Gain (Loss) on Derivatives

(in millions)	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
Gain (loss) on unsettled derivatives	\$ 31	\$ 81	\$ 350	\$ (48)
Gain (loss) on settled derivatives	17	(10)	(52)	20
Gain (loss) on derivatives (1)	\$ 48	\$ 71	\$ 298	\$ (28)

(1) Excludes \$3 million amortization of premiums paid related to certain call options for the three and nine months ended September 30, 2017, which is included in gain (loss) on derivatives on the condensed consolidated statement of operations.

We refer you to [Note 6](#) to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our gain (loss) on derivatives.

Loss on Early Extinguishment of Debt

- In September 2017, we used the proceeds of approximately \$1.1 billion from our September 2017 senior notes offering to repurchase approximately \$758 million of our 2020 Senior Notes and to repay the remaining \$327 million principal amount outstanding of our 2015 Term Loan. We recognized a loss of \$59 million for the redemption of these senior notes, which included \$53 million of premiums paid.

Table of Contents

- In the first half of 2017, we redeemed the remaining \$276 million principal amount outstanding of our 2018 Senior Notes, recognizing a loss of \$11 million.
- During the third quarter of 2016, we used proceeds from our \$1,247 million July 2016 equity offering to purchase and retire \$700 million of our outstanding senior notes due in the first quarter of 2018 and retire \$375 million of our \$750 million term loan entered into in November 2015. We recognized a loss of \$51 million for the redemption of these senior notes, which included \$50 million of premiums paid.

Income Taxes

	For the three months ended September 30,		For the nine months ended September 30,	
	2017	2016	2017	2016
(in millions except percentages)				
Income tax expense (benefit)	\$ (14)	\$ (20)	\$ (14)	\$ (20)
Effective tax rate	(21%)	3%	(2%)	1%

- The income tax benefits recognized for the three and nine months ended September 30, 2017 and 2016 primarily resulted from an expected alternative minimum tax refund, along with the expiration of a portion of our uncertain tax provision.
- Our low effective tax rate is the result of our recognition of a valuation allowance that reduced the deferred tax asset primarily related to our current net operating loss carryforward. 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.

New Accounting Standards Implemented in this Report

Refer to Note 15 to the unaudited condensed consolidated financial statements of this Quarterly Report for a discussion of new accounting standards which have been implemented.

New Accounting Standards Not Yet Implemented in this Report

Refer to [Note 15](#) to the unaudited condensed consolidated financial statements of this Quarterly Report for a discussion of new accounting standards which have not yet been implemented.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on funds generated from our operations, our cash and cash equivalents balance, our \$809 million revolving credit facilities and capital markets as our primary sources of liquidity. Although we have financial flexibility with our cash balance and the ability to draw on our revolving credit facilities as necessary, we continue to be committed to our capital discipline strategy of investing within our cash flow from operations, supplemented in 2017 by the remaining funds from the July 2016 equity issuance and the September 2016 asset sale in West Virginia.

Our cash flow from operating activities is highly dependent upon the sales prices that we receive for our natural gas and liquids production. Natural gas, oil and NGL prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See [“Quantitative and Qualitative Disclosures about Market Risks”](#) in [Item 3](#) and [Note 6](#) to the unaudited condensed consolidated financial statements included in this Quarterly Report for further details.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. At September 30, 2017, we had NYMEX price derivatives in place on 138 Bcf of our remaining targeted 2017 natural gas production, and 473 Bcf and 108 Bcf on our targeted 2018 and 2019 natural gas production, respectively. We also had commodity derivatives in place on 46 MBbls of our remaining targeted 2017 ethane production and 183 MBbls of our targeted 2018 ethane production.

Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to settle the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Table of Contents

Our short-term cash flows are also dependent on the timely collection of receivables from our customers and joint interest partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectable amounts. However, any sustained inaccessibility of credit by our customers and joint interest partners could adversely impact our cash flows.

Due to these above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we expect to adjust our discretionary uses of cash depending upon available cash flow. Further, we may from time to time seek to retire, rearrange or amend some or all of our outstanding debt, preferred stock or debt agreements through cash purchases, and/or exchanges, open market purchases, privately negotiated transactions, tender offers or otherwise. Such transactions, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Credit Arrangements and Financing Activities

We have taken substantial steps in managing our debt maturities and liquidity in 2017. These steps, discussed in further detail below, had the effect of extending maturities on total debt outstanding by reducing the amount of debt, net of cash and cash equivalents, coming due in 2020 from \$1,257 million as of June 30, 2017 to \$294 million as of September 30, 2017.

- In September 2017, we completed a public offering of \$650 million aggregate principal amount of our 7.50% senior notes due 2026 and \$500 million aggregate principal amount of our 7.75% senior notes due 2027, with net proceeds from the offering totaling approximately \$1.1 billion after underwriting discounts and offering expenses.
- The proceeds from the September 2017 offering were used to repurchase \$758 million of our 4.05% Senior Notes due 2020 and to repay the remaining \$327 million principal amount outstanding of our 2015 Term Loan.
- Also in September 2017, we entered into Amendment No. 1 to our credit agreement covering the \$1,191 million secured term loan and the \$743 million unsecured revolving facility entered into in June 2016. This amendment provides greater flexibility to our minimum liquidity covenant and allows us to retain the first \$500 million of net cash proceeds from asset sales that would have otherwise been required to be used for further debt reduction.
- During the first half of 2017, we redeemed the remaining \$276 million principal amount outstanding of our 2018 Senior Notes.

Our 2016 revolving credit facility provides borrowing capacity of \$743 million and matures in December 2020. The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least

\$765 million of our senior notes due in January 2020. As of September 30, 2017, we have repurchased approximately \$758 million of our 4.05% Senior Notes due 2020. Our 2013 revolving credit facility provides borrowing capacity of \$66 million and matures in December 2018. As of September 30, 2017, there were no borrowings under either revolving credit facility; however, there was \$323 million in letters of credit outstanding against the 2016 revolving credit facility.

As of September 30, 2017, we were in compliance with all of the covenants of the term loans and revolving credit facilities. Although we do not anticipate any violations of the financial covenants, our ability to comply with these covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and liquids. We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion of the covenant requirements of our term loans and revolving credit facilities.

At October 24, 2017, we had a long-term issuer credit rating of Ba3 by Moody's, a long-term debt rating of BB- by S&P and a long-term issuer default rating of BB by Fitch Ratings. Any downgrades in our public debt ratings by Moody's or S&P could increase our cost of funds and decrease our liquidity under our revolving credit facilities.

The credit status of the financial institutions participating in our revolving credit facilities could adversely impact our ability to borrow funds under the revolving credit facilities. Although we believe all of the lenders under the facilities have the ability to provide funds, we cannot predict whether each will be able to meet their obligation to us. We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion of our credit facilities.

Table of Contents

Cash Flows

(in millions)	For the nine months ended September 30,	
	2017	2016
Net cash provided by operating activities	\$ 789	\$ 337
Net cash provided by (used in) investing activities	(921)	43
Net cash provided by (used in) financing activities	(302)	1,079

Cash Flow from Operations

- Net cash provided by operating activities increased 134% or \$452 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to an increase in revenues resulting from improved realized commodity prices partially offset by lower production volumes and a reduction in realized derivative results.
- Net cash generated from operating activities provided 83% of our cash requirements for capital investments for the nine months ended September 30, 2017, compared to net cash from operating activities providing 89% of our cash requirements for capital investments for the same period in 2016, reflecting our commitment to our capital discipline strategy of investing within our cash flow from operations, supplemented by the 2016 equity issuance and asset sales.

Cash Flow from Investing Activities

(in millions)	For the nine months ended September 30,	
	2017	2016
Cash Flows from Investing Activities		

Additions to properties and equipment	\$ 943	\$ 391
Adjustments for capital investments		
Changes in capital accruals	(13)	(24)
Other non-cash adjustments to properties and equipment	16	9
Total capital investing	\$ 946	\$ 376

(in millions except percentages)	For the three months ended			For the nine months ended		
	September 30, 2017	September 30, 2016	Increase/ (Decrease)	September 30, 2017	September 30, 2016	Increase/ (Decrease)
E&P capital investing (1)	320	179		921	372	
Midstream capital investing	9	1		21	3	
Other capital investing	2	–		4	1	
Total capital investing	\$ 331	\$ 180	84%	\$ 946	\$ 376	152%

(1) Includes \$54 million and \$62 million of capitalized interest and internal costs for the three months ended September 30, 2017 and 2016, respectively, and \$159 million and \$183 million of capitalized interest and internal costs for the nine months ended September 30, 2017 and 2016, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties.

- Total E&P capital investing increased \$141 million for the three months ended September 30, 2017, compared to the same period in 2016, as a \$149 million increase in direct E&P capital investing was only partially offset by an \$8 million decrease in capitalized interest and internal costs.
- Total E&P capital investing increased \$549 million for the nine months ended September 30, 2017, compared to the same period in 2016, as a \$573 million increase in direct E&P capital investing was only partially offset by a \$24 million decrease in capitalized interest and internal costs. We suspended drilling activity in the first half of 2016 due to an unfavorable commodity price environment.
- The increase in E&P capital investments for the three and nine months ended September 30, 2017, as compared to the same periods in 2016, reflects our operational flexibility in light of current and expected economic conditions as we adjusted our activities based on our anticipated cash flows from operation.
 - The decrease in capitalized interest for the three and nine months ended September 30, 2017, compared to the same periods in 2016, was primarily due to the evaluation of a portion of our Southwest Appalachia assets acquired in December 2014.

Table of Contents

- Midstream capital investing increases of \$8 million and \$18 million for the three and nine months ended September 30, 2017, respectively, compared to the same periods in 2016, related primarily to the purchase of several of our leased compressors during 2017 which were subsequently sold to third parties for a year-to-date net gain of \$3 million.

Actual capital expenditure levels may vary significantly from period to period due to many factors, including drilling results, natural gas, oil and NGL prices, industry conditions, the prices and availability of goods and services, and the extent to which properties are acquired or non-strategic assets are sold.

Cash Flow from Financing Activities

(in millions except percentages)	September 30, 2017	December 31, 2016	Increase/ (Decrease)
Short-term debt	\$ 40	\$ 41	\$ (1)
Long-term debt	4,396	4,612	(216)
Total debt	\$ 4,436	\$ 4,653	\$ (217)
Equity	\$ 1,652	\$ 917	\$ 735
Total debt to capitalization ratio	73%	84%	(11%)
Total debt	\$ 4,436	\$ 4,653	\$ (217)
Less: Cash and cash equivalents	989	1,423	(434)
Debt, net of cash and cash equivalents (1)	\$ 3,447	\$ 3,230	\$ 217

- (1) Debt, net of cash and cash equivalents is a non-GAAP financial measure of a company's ability to repay its debts if they were all due today.

- Net cash used in financing activities for the nine months ended September 30, 2017 was \$302 million, compared to net cash provided by financing activities of \$1,079 million for the same period in 2016.
- In September 2017, we completed a public offering of \$650 million aggregate principal amount of our 7.50% senior notes due 2026 and \$500 million aggregate principal amount of our 7.75% senior notes due 2027, with net proceeds from the offering totaling approximately \$1.1 billion, after approximately \$17 million in offering expenses.
- The proceeds from the September 2017 offering were used to repay \$758 million of our 4.05% Senior Notes due 2020 and the remaining \$327 million principal amount outstanding of our 2015 Term Loan. We recognized a loss on early extinguishment of debt of \$59 million.

- In the first half of 2017, we redeemed \$276 million principal amount outstanding of our 2018 Senior Notes. We recognized a loss on early extinguishment of debt of \$11 million.
- The net cash provided by financing activities in 2016 resulted primarily from our fully-drawn 2016 Term Loan.

We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion of our outstanding debt and credit facilities.

Working Capital

- We had positive working capital of \$692 million at September 30, 2017 and positive working capital of \$808 million at December 31, 2016.
- The positive working capital as of September 30, 2017 and December 31, 2016 was primarily due to \$1.0 billion and \$1.4 billion of cash and cash equivalents, respectively.

Off-Balance Sheet Arrangements

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of September 30, 2017, our material off-balance sheet arrangements and transactions include operating lease arrangements and \$323 million in letters of credit outstanding under our 2016 revolving credit facility. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources. For more information regarding off-balance sheet arrangements, we refer you to “Contractual Obligations and Contingent Liabilities and Commitments” in our 2016 Annual Report on Form 10-K.

Table of Contents

Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Other than the firm transportation and gathering agreements discussed below, there have been no material changes to our contractual obligations from those disclosed in our 2016 Annual Report.

Contingent Liabilities and Commitments

As of September 30, 2017, our contractual obligations for demand and similar charges under firm transport and gathering agreements to guarantee access capacity on natural gas and liquids pipelines and gathering systems totaled approximately \$8.9 billion, \$3.7 billion of which related to access capacity on future pipeline and gathering infrastructure projects that still require the granting of regulatory approvals and/or additional construction efforts. This amount also included guarantee obligations of up to \$832 million. As of September 30, 2017, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					More than 8 Years
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	
	(in millions)					
Infrastructure Currently in Service	\$ 5,136	\$ 196	\$ 1,105	\$ 524	\$ 1,492	\$ 1,819
Pending Regulatory Approval and/or Construction (1)	3,722	432	458	702	114	2,016
Total Transportation Charges	\$ 8,858	\$ 628	\$ 1,563	\$ 1,226	\$ 1,606	\$ 3,835

(1) Based on the estimated in-service dates as of September 30, 2017.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. For the nine months ended September 30, 2017, we have contributed \$11 million to the pension and postretirement benefit plans. We expect to contribute an additional \$3 million to our pension and postretirement benefit plans during the remainder of 2017. As of September 30, 2017 and December 31, 2016, we recognized liabilities of \$46 million and \$49 million, respectively, as a result of the underfunded status of our pension and other postretirement benefit plans. See Note 11 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion about our pension and other postretirement benefits.

We are subject to various litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties, employment matters, traffic incidents and pollution,

contamination or nuisance. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. Management believes that current litigation, claims and proceedings, individually or in aggregate and after taking into account insurance, are not likely to have a material adverse impact on our financial position, results of operations or cash flows, although it is possible that adverse outcomes could have a material adverse effect on our results of operations or cash flows for the period in which the effect of that outcome becomes reasonably estimable. Many of these matters are in early stages, so the allegations and the damage theories have not been fully developed, and are all subject to inherent uncertainties; therefore, management's view may change in the future. For further information, we refer you to "Litigation" and "Environmental Risk" in Note 10 to the unaudited condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report.

We are also subject to laws and regulations relating to the protection of the environment. Environmental and cleanup related costs of a non-capital nature are accrued when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or results of operations.

Table of Contents

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as service costs and credit risk concentrations. We use fixed price swap agreements, fixed price options, basis swaps and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risk is also overseen by our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our physical commodity purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues for the nine months ended September 30, 2017. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

As of September 30, 2017, we had approximately \$3.3 billion of outstanding senior notes with a weighted average interest rate of 6.21% and \$1.2 billion of term loan debt with a variable interest rate of 3.70%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date							Total
	2017	2018	2019	2020	2021	Thereafter		
Fixed Rate Payments (1)	\$ 40	\$ –	\$ –	\$ 92	\$ –	\$ 3,150	\$ 3,282	
Weighted Average Interest Rate	7.21 %	– %	– %	5.80 %	– %	6.21 %	6.21 %	
Variable Rate Payments (1)	–	–	–	1,191(2)	–	–	1,191	
Weighted Average Interest Rate	– %	– %	– %	3.70 %	– %	– %	3.70 %	

(1) Excludes unamortized debt issuance costs and debt discounts.

(2) The maturity date will accelerate to October 2019 if, by that date, we have not amended, redeemed or refinanced at least \$765 million of our 2020 Senior Notes. As of September 30, 2017, we have redeemed \$758 million principal amount of our 2020 Senior Notes.

Commodities Risk

We use over-the-counter fixed price swap agreements and options to protect sales of our production against the inherent risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps) and transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps). For additional information on our derivatives and risk management, see Note 6 in the unaudited condensed consolidated financial statements included in this Quarterly Report.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas. However, the market price risk is offset by the gain or loss recognized upon the related sale or purchase of the natural gas that is financially protected. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major banks and integrated energy companies that management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We have not incurred any counterparty losses related to non-performance and do not anticipate any losses given the information we have currently. However, we cannot be certain that we will not experience such losses in the future.

Table of Contents

Item 4. Controls and Procedures.

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2017 at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

Refer to "Litigation" and "Environmental Risk" in Note 10 to the unaudited condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report for a discussion of the Company's legal proceedings.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to our risk factors as disclosed in Item 1A of Part I in the Company's 2016 Annual Report.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

Our sand mining operations in support of our E&P business are subject to regulation by the Federal Mine Safety and Health Administration under the Federal Mine Safety and Health Act of 1977. Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.106) is included in Exhibit 95.1 to this Quarterly Report.

ITEM 5. OTHER INFORMATION.

Not applicable.

Table of Contents

ITEM 6. EXHIBITS.

- (10.1)* Separation and Release Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling
 - (10.2)* Amendment to Awards Agreement dated August 23, 2017 between Southwestern Energy Company and Mark K. Boling
 - (31.1)* Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
 - (31.2)* Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
 - (32.1)* Certification of CEO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
 - (32.2)* Certification of CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
 - (95.1)* Mine Safety Disclosure
 - (101.INS) Interactive Data File Instance Document
 - (101.SCH) Interactive Data File Schema Document
 - (101.CAL) Interactive Data File Calculation Linkbase Document
 - (101.LAB) Interactive Data File Label Linkbase Document
 - (101.PRE) Interactive Data File Presentation Linkbase Document
 - (101.DEF) Interactive Data File Definition Linkbase Document
- *Filed herewith

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.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: October /s/ JENNIFER STEWART
26,
2017

Jennifer Stewart
Senior Vice President and
Chief Financial Officer – Interim

