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

Form 10-Q

(Mark One)
[X] Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended **June 30, 2016**

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 or organization)	(I.R.S. Employer Identification No.)
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, or a smaller reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

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 July 19, 2016
Common Stock, Par Value $0.01	493,455,527

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2016

PART I – FINANCIAL INFORMATION

PART II – OTHER INFORMATION

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," "objective," "guidance," "outlook," "effort," "expect," "believe," "predict," "budget," "projection," "goal," "forecast," "target" or similar words.

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:

- 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 profitability 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;
- 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.

PART I – FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS.

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

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	(in millions, except share/per share amounts)			
Operating Revenues:				
Gas sales	**$ 251**	$ 457	**$ 566**	$ 1,082
Oil sales	**20**	24	**31**	41
NGL sales	**20**	15	**37**	33
Marketing	**196**	222	**394**	447
Gas gathering	**35**	46	**73**	94
	522	764	**1,101**	1,697
Operating Costs and Expenses:				
Marketing purchases	**197**	219	**393**	441
Operating expenses	**151**	176	**316**	331
General and administrative expenses	**56**	60	**110**	128
Restructuring charges	**11**	–	**75**	–
Depreciation, depletion and amortization	**107**	308	**250**	601
Impairment of natural gas and oil properties	**470**	1,535	**1,504**	1,535
Gain on sale of assets, net	**–**	(277)	**–**	(277)
Taxes, other than income taxes	**22**	27	**45**	57
	1,014	2,048	**2,693**	2,816
Operating Loss	**(492)**	(1,284)	**(1,592)**	(1,119)
Interest Expense:				
Interest on debt	**56**	52	**109**	102
Other interest charges	**2**	3	**4**	52
Interest capitalized	**(41)**	(54)	**(82)**	(102)
	17	1	**31**	52
Other Income (Loss), Net	**–**	3	**(3)**	2
Gain (Loss) on Derivatives	**(85)**	1	**(99)**	15
Loss Before Income Taxes	**(594)**	(1,281)	**(1,725)**	(1,154)
Provision (Benefit) for Income Taxes:				
Current	**–**	7	**–**	7
Deferred	**(1)**	(500)	**–**	(451)
	(1)	(493)	**–**	(444)
Net Loss	**$ (593)**	$ (788)	**$ (1,725)**	$ (710)
Mandatory convertible preferred stock dividend	**27**	27	**54**	52
Net Loss Attributable to Common Stock	**$ (620)**	$ (815)	**$ (1,779)**	$ (762)
Loss Per Common Share:				
Basic	**$ (1.61)**	$ (2.13)	**$ (4.63)**	$ (2.01)
Diluted	**$ (1.61)**	$ (2.13)	**$ (4.63)**	$ (2.01)
Weighted Average Common Shares Outstanding:				
Basic	**385,594,815**	382,114,011	**384,232,831**	378,797,446
Diluted	**385,594,815**	382,114,011	**384,232,831**	378,797,446

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

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

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	(in millions)			
Net loss	**$ (593)**	$ (788)	**$ (1,725)**	$ (710)
Change in derivatives:				
Settlements [1]	**–**	(33)	**–**	(58)
Change in fair value of derivative instruments [2]	**–**	(4)	**–**	13
Total change in derivatives	**–**	(37)	**–**	(45)
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost and net loss included in net periodic pension cost [3]	**(1)**	–	**–**	–
Net gain incurred in period [4]	**4**	–	**4**	–
Change in currency translation adjustment	**–**	2	**3**	(4)
Comprehensive loss	**$ (590)**	$ (823)	**$ (1,718)**	$ (759)

(1) Net of ($20) million and ($37) million in taxes for the three and six months ended June 30, 2015.

(2) Net of $1 million and $8 million in taxes for the three and six months ended June 30, 2015.

(3) Net of $1 million in taxes for the six months ended June 30, 2016.

(4) Net of $1 million in taxes for the three and six months ended June 30, 2016.

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

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

	June 30, 2016	December 31, 2015
ASSETS	(in millions)	
Current assets:		
Cash and cash equivalents	$ **998**	$ 15
Accounts receivable, net	**235**	327
Derivative assets	**16**	3
Other current assets	**29**	48
Total current assets	**1,278**	393
Natural gas and oil properties, using the full cost method, including $3,382 million as of June 30, 2016 and $3,727 million as of December 31, 2015 excluded from amortization	**22,657**	22,478
Gathering systems	**1,280**	1,280
Other	**592**	606
Less: Accumulated depreciation, depletion and amortization	**(18,582)**	(16,821)
Total property and equipment, net	**5,947**	7,543
Other long-term assets	**152**	150
TOTAL ASSETS	$ **7,377**	$ 8,086
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	$ **1**	$ 1
Accounts payable	**296**	513
Taxes payable	**61**	64
Interest payable	**75**	75
Dividends payable	**27**	27
Derivative liabilities	**76**	3
Other current liabilities	**55**	24
Total current liabilities	**591**	707
Long-term debt	**5,767**	4,704
Pension and other postretirement liabilities	**51**	50
Other long-term liabilities	**395**	343
Total long-term liabilities	**6,213**	5,097
Commitments and contingencies (Note 11)		
Equity:		
Common stock, $0.01 par value; 1,250,000,000 shares authorized; issued 392,496,825 (1) shares as of June 30, 2016 (does not include 2,100,119 shares declared as a stock dividend on June 14, 2016 to be issued on July 15, 2016) and 390,138,549 as of December 31, 2015	**4**	4
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 as of June 30, 2016 and December 31, 2015, conversion in January 2018	**–**	–
Additional paid-in capital	**3,418**	3,409
Accumulated deficit	**(2,807)**	(1,082)
Accumulated other comprehensive loss	**(41)**	(48)
Common stock in treasury, 31,269 shares as of June 30, 2016 and 47,149 shares as of December 31, 2015, respectively	**(1)**	(1)
Total equity	**573**	2,282
TOTAL LIABILITIES AND EQUITY	$ **7,377**	$ 8,086

(1) Does not include 98,900,000 shares of common stock issued in July 2016.

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

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

	For the six months ended June 30,	
	2016	2015
	(in millions)	
Cash Flows From Operating Activities		
Net loss	$ **(1,725)**	$ (710)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	**250**	603
Impairment of natural gas and oil properties	**1,504**	1,535
Amortization of debt issuance costs	**4**	49
Deferred income taxes	**–**	(451)
Loss on derivatives, net of settlement	**129**	71
Stock-based compensation	**17**	12
Gain on sale of assets, net	**–**	(277)
Restructuring charges	**29**	–
Other	**7**	–
Change in assets and liabilities:		
Accounts receivable	**92**	162
Inventories	**(7)**	–
Accounts payable	**(139)**	(22)
Taxes payable	**(3)**	(30)
Interest payable	**–**	14
Other assets and liabilities	**7**	(16)
Net cash provided by operating activities	**165**	940
Cash Flows From Investing Activities		
Capital investments	**(241)**	(974)
Acquisitions	**–**	(569)
Proceeds from sale of property and equipment	**54**	703
Other	**1**	10
Net cash used in investing activities	**(186)**	(830)
Cash Flows From Financing Activities		
Payments on current portion of long-term debt	**(1)**	(1)
Payments on long-term debt	**–**	(500)
Payments on short-term debt	**–**	(4,500)
Payments on revolving credit facility	**(3,268)**	(1,534)
Borrowings under revolving credit facility	**3,152**	1,804
Payments on commercial paper	**(242)**	(1,182)
Borrowings under commercial paper	**242**	1,288
Change in bank drafts outstanding	**(21)**	(1)
Proceeds from issuance of long-term debt	**1,191**	2,200
Debt issuance costs	**(16)**	(17)
Proceeds from issuance of common stock	**–**	669
Proceeds from issuance of mandatory convertible preferred stock	–	1,673
Preferred stock dividend	**(27)**	(25)
Other	**(6)**	–
Net cash provided by (used in) financing activities	**1,004**	(126)
Increase (decrease) in cash and cash equivalents	**983**	(16)
Cash and cash equivalents at beginning of year	**15**	53
Cash and cash equivalents at end of period	$ **998**	$ 37

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

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

	Common Stock		Preferred Stock					
	Shares Issued	Amount	Shares	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
	(in millions, except share amounts)							
Balance at December 31, 2015	390,138,549	$ 4	1,725,000	$ 3,409	$ (1,082)	$ (48)	$ (1)	$ 2,282
Comprehensive loss:								
Net loss	–	–	–	–	(1,725)	–	–	(1,725)
Other comprehensive income	–	–	–	–	–	7	–	7
Total comprehensive loss	–	–	–	–	–	–	–	(1,718)
Stock-based compensation	–	–	–	42	–	–	–	42
Preferred stock dividend	3,024,737	–	–	(27)	–	–		(27)
Issuance of restricted stock	84,165	–	–	–	–	–	–	–
Cancellation of restricted stock	(89,095)	–	–	–	–	–	–	–
Tax withholding – stock compensation	(661,531)	–	–	(6)	–	–	–	(6)
Balance at June 30, 2016	**392,496,825**	**$ 4**	**1,725,000**	**$ 3,418**	**$ (2,807)**	**$ (41)**	**$ (1)**	**$ 573**

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

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 and oil 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"). Southwestern conducts most of its businesses through subsidiaries and operates principally in two segments: E&P and Midstream.

Exploration and Production. Southwestern's primary business is the exploration for and production of natural gas and oil, with current operations principally focused on the development of unconventional natural gas reservoirs located in Pennsylvania, West Virginia and Arkansas. The Company's operations in northeast Pennsylvania, herein referred to as "Northeast Appalachia," are primarily focused on the unconventional natural gas reservoir known as the Marcellus Shale. Operations in West Virginia and southwest Pennsylvania, herein referred to as "Southwest Appalachia," are focused on the Marcellus Shale, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs. Collectively, Southwestern refers to its properties located in Pennsylvania and West Virginia as the "Appalachian Basin." The Company's operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. Southwestern has exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which it is currently exploring for new development opportunities. The Company also has drilling rigs located in Pennsylvania, West Virginia and Arkansas and provides oilfield products and services, principally serving its E&P operations.

Midstream. Through the Company's affiliated midstream subsidiaries, Southwestern engages in natural gas gathering activities in Arkansas and Louisiana. These activities primarily support the Company's E&P operations and generate revenue from fees associated with the gathering of natural gas. Southwestern's marketing activities capture opportunities that arise through the marketing and transportation of the natural gas, oil and NGLs produced in its E&P operations.

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, 2015 ("2015 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 2015 Annual Report.

Certain reclassifications have been made to the prior year financial statements to conform to the 2016 presentation. The effects of the reclassifications were not material to the Company's unaudited condensed consolidated financial statements.

(2) CASH AND CASH EQUIVALENTS

The following table presents a summary of cash and cash equivalents as of June 30, 2016 and December 31, 2015:

	June 30, 2016	December 31, 2015
	(in millions)	
Cash	$ **12**	$ 15
Marketable securities [1]	**986**	–
Total cash and cash equivalents	$ **998**	$ 15

(1) Consists of money market funds.

(3) REDUCTION IN WORKFORCE

In January 2016, the Company announced a 40% workforce reduction of approximately 1,100 employees 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 six months ended June 30, 2016:

	For the three months ended June 30, 2016	For the six months ended June 30, 2016
	(in millions)	
Severance (including payroll taxes) [1]	$ 2	$ 44
Stock-based compensation [2]	6	24
Pension and other postretirement benefits [3]	3	3
Other benefits	–	3
Outplacement services, other	–	1
Total restructuring charges [4]	$ 11	$ 75

(1) Includes $1 million related to executive management restructuring for the three and six months ended June 30, 2016.

(2) Includes $3 million related to executive management restructuring for the three and six months ended June 30, 2016.

(3) Includes non-cash charges related to the curtailment and settlement of the pension and other postretirement benefit plans. See Note 12 for additional details regarding the Company's retirement and employee benefit plans.

(4) Total restructuring charges were $11 million and less than $1 million for the Company's E&P and Midstream segments, respectively, for the three months ended June 30, 2016. For the six months ended June 30, 2016, restructuring charges were $72 million and $3 million for the Company's E&P and Midstream segments, respectively.

The following table presents a summary of liabilities associated with the Company's restructuring activities at June 30, 2016, which are reflected in accounts payable on the unaudited condensed consolidated balance sheet (in millions):

Liability at March 31, 2016	$ 24
Additions	2
Distributions	(24)
Liability at June 30, 2016	**$ 2**

Severance payments and other separation costs related to restructuring will be completed by the end of the fourth quarter, resulting in the recognition of approximately $0.5 million of additional expense in the second half of 2016.

(4) ACQUISITIONS AND DIVESTITURES

In June 2016, the Company entered into a definitive agreement with Antero Resources Corporation to sell approximately 55,000 net acres in West Virginia for $450 million, subject to customary adjustments. The net book value of these assets is in the full cost pool and was held in the E&P segment as of June 30, 2016. The transaction is expected to close in the third quarter of 2016, subject to customary closing conditions and purchase price adjustments. At June 30, 2016, a $45 million deposit from Antero Resources Corporation was included in other current liabilities within the unaudited condensed consolidated balance sheet. The Company intends to use $375 million of proceeds from the sale for general corporate purposes, including to fund capital projects, and to use the remainder to reduce indebtedness.

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $211 million. The net book value of these assets was primarily in the full cost pool and was held in the E&P segment as of the closing date. The proceeds from the transaction were used to reduce the Company's debt. Approximately $205 million of the proceeds received were recorded as a reduction of the capitalized costs of the Company's natural gas and oil properties in the United States pursuant to the full cost method of accounting.

In April 2015, the Company sold its gathering assets located in Bradford and Lycoming counties in northeast Pennsylvania to Howard Midstream Energy Partners, LLC for an adjusted sales price of approximately $489 million. The net book value of these assets was $206 million and was held in the Midstream segment as of the closing date. A gain on sale of $283 million was recognized and is included in gain on sale of assets, net on the unaudited condensed consolidated statement of operations. The assets included approximately 100 miles of natural gas gathering pipelines, with nearly 600 million cubic feet per day of capacity. The proceeds from the transaction were used to substantially repay borrowings under the Company's $500 million term loan facility that would have matured in December 2016.

In January 2015, the Company completed an acquisition of certain natural gas and oil assets including approximately 46,700 net acres in northeast Pennsylvania from WPX Energy, Inc. for an adjusted purchase price of $270 million (the "WPX Property Acquisition"). This acreage was producing approximately 50 million net cubic feet of gas per day from 63 operated horizontal wells as of December 2014. As part of this transaction, the Company assumed firm transportation capacity of 260 million cubic feet of gas per day predominantly on the Millennium pipeline. The firm transport is being amortized over 19 years. As of June 30, 2016 and December 31, 2015 the Company has amortized $13 million and $8 million, respectively. This transaction was funded with the revolving credit facility and was accounted for as a business combination.

In January 2015, the Company completed an acquisition of certain natural gas and oil assets from Statoil ASA covering approximately 30,000 acres in West Virginia and southwest Pennsylvania comprising approximately 20% of Statoil's interests in that acreage for $357 million, (the "Statoil Property Acquisition"). All of these assets were also assets in which the Company had acquired interests under the Chesapeake Property Acquisition, as defined below. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The Company allocated the purchase price to natural gas and oil properties, based on the respective fair values of the assets acquired.

In December 2014, the Company completed an acquisition of certain oil and gas assets from Chesapeake Energy Corporation covering approximately 413,000 net acres in West Virginia and southwest Pennsylvania targeting natural gas, NGLs and crude oil contained in the Upper Devonian, Marcellus and Utica Shales for approximately $5.0 billion (the "Chesapeake Property Acquisition"). The transaction was temporarily financed using a $4.5 billion 364-day senior unsecured bridge term loan credit facility and a $500 million two-year unsecured term loan. The Company repaid all principal and interest outstanding on the $4.5 billion bridge facility in January 2015 after permanent financing was finalized and, as a result, expensed $47 million of short-term unamortized debt issuance costs related to the bridge facility in January 2015, recognized in other interest charges on the unaudited condensed consolidated statement of operations. The term loan facility was repaid in full in April 2015 with proceeds from the divestiture of the Company's northeastern Pennsylvania gathering assets and borrowings under the revolving credit facility.

(5) 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) plus the lower of cost or market value of unproved properties. 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 $2.24 per MMBtu, West Texas Intermediate oil of $39.63 per barrel and NGLs of $5.87 per barrel, adjusted for market differentials, the Company's net book value of its United States and Canada natural gas and oil properties exceeded the ceiling by $297 million (net of tax) at June 30, 2016 and resulted in a non-cash ceiling test impairment. The Company had no hedge positions that were designated for hedge accounting as of June 30, 2016. 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 $3.39 per MMBtu, West Texas Intermediate oil of $68.17 per barrel and NGLs of $12.53 per barrel, adjusted for market differentials, the net book value of the Company's United States natural gas and oil properties exceeded the ceiling by $944 million (net of tax) at June 30, 2015 and resulted in a non-cash ceiling test impairment. Cash flow hedges of natural gas production in place increased the ceiling amount by approximately $60 million as of June 30, 2015. In the third and fourth quarters of 2015, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $1,746 million (net of tax) at September 30, 2015 and $1,586 million (net of tax) at December 31, 2015, resulting in non-cash ceiling test impairments in each quarter. In the first quarter of 2016, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $641 million (net of tax) at March 31, 2016, resulting in a non-cash ceiling test impairment in the quarter.

(6) 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 and performance units, the assumed conversion of mandatory convertible preferred stock and the shares of common stock declared as a preferred stock dividend. 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, after underwriting discount and offering expenses, from the common stock offering were approximately $1,247 million. 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 will be used for general corporate purposes. The 98,900,000 shares of common stock were issued in July 2016 and are therefore not included in the outstanding common stock share counts or earnings per share calculations for the quarter ended June 30, 2016.

In January 2015, the Company completed concurrent underwritten public offerings of 30,000,000 shares of its common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). The common stock offering was priced at $23.00 per share. Net proceeds, after underwriting discount and expenses, from the common stock offering were approximately $669 million. Net proceeds, after underwriting discount and expenses, from the depositary share offering were approximately $1.7 billion. Each depositary share represents a 1/20th interest in a share of the Company's mandatory convertible preferred stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share). The proceeds from the offerings were used to partially repay borrowings under the Company's $4.5 billion 364-day bridge facility with the remaining balance of the bridge facility fully repaid with proceeds from the Company's January 2015 public offering of $2.2 billion in long-term senior notes.

The mandatory convertible preferred stock 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 (and, 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 June 14, 2016, the Company declared its quarterly dividend, payable to holders of the mandatory convertible preferred stock, and announced that it would pay the dividend in common stock, in lieu of cash, to the extent permitted by the certificate of designations for the Series B preferred stock. The Company issued 2,100,119 shares of common stock on July 15, 2016 in payment for the dividend.

The following table presents the computation of earnings per share for the three and six months ended June 30, 2016 and 2015:

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	(in millions, except share/per share amounts)			
Net loss	**$ (593)**	$ (788)	**$ (1,725)**	$ (710)
Mandatory convertible preferred stock dividend	**27**	27	**54**	52
Net loss attributable to shareholders	**$ (620)**	$ (815)	**$ (1,779)**	$ (762)
Number of common shares:				
Weighted average outstanding	**385,594,815**	382,114,011	**384,232,831**	378,797,446
Issued upon assumed exercise of outstanding stock options (1)	**–**	–	**–**	–
Effect of issuance of non-vested restricted common stock (2)	**–**	–	**–**	–
Effect of issuance of non-vested performance units (3)	**–**	–	**–**	–
Effect of issuance of mandatory convertible preferred stock (4)	**–**	–	**–**	–
Effect of declaration of preferred stock dividends (5)	**–**	–	**–**	–
Weighted average and potential dilutive outstanding	**385,594,815**	382,114,011	**384,232,831**	378,797,446
Loss per common share (6):				
Basic	**$ (1.61)**	$ (2.13)	**$ (4.63)**	$ (2.01)
Diluted	**$ (1.61)**	$ (2.13)	**$ (4.63)**	$ (2.01)

(1) Due to the net loss for the three and six months ended June 30, 2016 and 2015, the unvested stock options were not recognized in diluted earnings per share calculations as they would be antidilutive. Options for 4,028,819 shares and 4,781,109 shares were excluded from the calculation of diluted shares for the three and six months ended June 30, 2016, respectively, because they would have had an antidilutive effect. Options for 3,832,533 shares and 3,768,666 shares were excluded from the calculation of diluted shares for the three and six months ended June 30, 2015, respectively, because they would have had an antidilutive effect.

(2) Due to the net loss for the three and six months ended June 30, 2016 and 2015, the unvested share-based payments were not recognized in diluted earnings per share calculations as they would be antidilutive. The calculation excluded 3,353,371 shares and 2,844,365 shares of restricted stock for the three and six months ended June 30, 2016, respectively, because they would have had an antidilutive effect. The calculation excluded 1,507,788 shares and 1,787,257 shares of restricted stock for the three and six months ended June 30, 2015, respectively, because they would have had an antidilutive effect.

(3) Due to the net loss for the three and six months ended June 30, 2016, 780,920 shares and 577,624 shares, respectively, of performance units were excluded from the calculation of diluted earnings per share as they would have had an antidilutive effect. Due to the net loss for the three and six months ended June 30, 2015, the calculation excluded 129,202 shares and 116,185 shares, respectively, of performance units as they would have had an antidilutive effect.

(4) Due to the net loss for the three and six months ended June 30, 2016, 74,999,895 of weighted average common shares issuable upon the assumed conversion of the mandatory convertible preferred stock were excluded from the diluted earnings per share calculation, respectively, as they would be antidilutive. Due to the net loss for the three and six months ended June 30, 2015, 72,723,440 and 64,687,701 of weighted average common shares issuable upon the assumed conversion of the mandatory convertible preferred stock were excluded from the diluted earnings per share calculation, respectively, as they would be antidilutive.

(5) Due to the net loss for the three months ended June 30, 2016, 2,100,119 shares of common stock declared as preferred stock dividends were excluded from the diluted earnings per share calculations as they would have had an antidilutive effect.

(6) Does not include the effect of 98,900,000 shares of common stock issued in July 2016.

(7) 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 June 30, 2016, the Company's derivative financial instruments consisted of fixed price swaps, purchased put options, two-way costless collars, three-way costless collars, basis swaps, sold call options and interest rate swaps. The Company had basis swaps and sold call options as of December 31, 2015. 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 from the counterparty by payment of a cash premium. If the market price is lower than the put's strike price at the time of settlement, the Company receives from the counterparty such difference on purchased put options. 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). 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 price and the ceiling price, 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 two-way costless collar and a sold put option. 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 middle strike price and the ceiling price, no payments are due from either party, (3) if the index is between the lowest strike price and the middle strike price, the Company will receive the difference between the middle strike price and the index price, and (4) if the index price is below the floor 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.

The Company utilizes counterparties for its derivative instruments that it believes are credit-worthy 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, the events in the financial markets in recent years demonstrate 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 June 30, 2016.

		Weighted Average Price per MMBtu					
	Volume (Bcf)	Swaps	Sold Puts	Purchased Puts	Sold Calls	Basis Differential	Fair value at June 30, 2016 ($ in millions)
Financial protection on production							
2016							
Fixed price swaps	61	$ 2.57	$ –	$ –	$ –	$ –	$ (24)
Purchased put options	17	$ –	$ –	$ 2.34	$ –	$ –	$ –
Two-way costless collars	12	$ –	$ –	$ 2.76	$ 3.35	$ –	$ (1)
Basis swaps	7	$ –	$ –	$ –	$ –	$ 0.36	$ 5
Total	97						$ (20)
2017							
Fixed price swaps	144	$ 3.07	$ –	$ –	$ –	$ –	$ (16)
Two-way costless collars	47	$ –	$ –	$ 2.90	$ 3.33	$ –	$ (4)
Three-way costless collars	18	$ –	$ 2.25	$ 2.75	$ 3.56	$ –	$ (2)
Basis swaps	15	$ –	$ –	$ –	$ –	$ 0.02	$ (6)
Total	224						$ (28)
Sold call options							
2016	60	$ –	$ –	$ –	$ 5.00	$ –	$ –
2017	86	$ –	$ –	$ –	$ 3.25	$ –	$ (30)
2018	63	$ –	$ –	$ –	$ 3.50	$ –	$ (18)
2019	52	$ –	$ –	$ –	$ 3.50	$ –	$ (17)
2020	32	$ –	$ –	$ –	$ 3.75	$ –	$ (10)
Total	293						$ (75)

The balance sheet classification of the assets related to derivative financial instruments (none of which are designated for hedge accounting) are summarized below as of June 30, 2016 and December 31, 2015:

	Derivative Assets			
	Balance Sheet Classification	Fair Value		
		June 30, 2016	December 31, 2015	
		(in millions)		
Derivatives not designated as hedging instruments:				
Fixed price swaps	Derivative assets	$ **1**	$ –	
Two-way costless collars	Derivative assets	**6**	–	
Three-way costless collars	Derivative assets	**2**	–	
Basis swaps	Derivative assets	**7**	3	
Two-way costless collars	Other long-term assets	**6**	–	
Three-way costless collars	Other long-term assets	**2**	–	
Total derivative assets		$ **24**	$ 3	

	Derivative Liabilities		
	Balance Sheet Classification	Fair Value	
		June 30, 2016	December 31, 2015
		(in millions)	
Derivatives not designated as hedging instruments:			
Fixed price swaps	Derivative liabilities	$ **36**	$ –
Two-way costless collars	Derivative liabilities	**10**	–
Three-way costless collars	Derivative liabilities	**3**	–
Basis swaps	Derivative liabilities	**8**	–
Sold call options	Derivative liabilities	**16**	–
Interest rate swaps	Derivative liabilities	**3**	3
Fixed price swaps	Other long-term liabilities	**5**	–
Two-way costless collars	Other long-term liabilities	**7**	–
Three-way costless collars	Other long-term liabilities	**3**	–
Sold call options	Other long-term liabilities	**59**	–
Interest rate swaps	Other long-term liabilities	**5**	2
Total derivative liabilities		$ **155**	$ 5

At June 30, 2016, the net fair value of the Company's financial instruments related to natural gas was a $123 million liability. The net fair value of the Company's interest rate swaps was an $8 million liability at June 30, 2016.

Derivative Contracts not Designated for Hedge Accounting

As of June 30, 2016, the Company did not have any 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. Changes in the fair value of the interest rate swaps are included in gain (loss) on derivatives in the unaudited condensed consolidated statements of operations.

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, sold call options, and interest rate swaps not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three and six months ended June 30, 2016 and 2015:

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Unsettled	Gain (Loss) on Derivatives, Unsettled Recognized in Earnings — For the three months ended June 30, 2016	2015	For the six months ended June 30, 2016	2015
		(in millions)			
Fixed price swaps	Gain (Loss) on Derivatives	**$ (60)**	$ (55)	**$ (40)**	$ (73)
Purchased put options	Gain (Loss) on Derivatives	**(15)**	–	**–**	–
Two-way costless collars	Gain (Loss) on Derivatives	**(5)**	–	**(5)**	–
Three-way costless collars	Gain (Loss) on Derivatives	**(2)**	–	**(2)**	–
Basis swaps	Gain (Loss) on Derivatives	**(1)**	3	**(4)**	(5)
Sold call options	Gain (Loss) on Derivatives	**(25)**	–	**(75)**	8
Interest rate swaps	Gain (Loss) on Derivatives	**–**	2	**(3)**	(1)
Total loss on unsettled derivatives		**$ (108)**	$ (50)	**$ (129)**	$ (71)

Derivative Instrument	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled	Gain (Loss) on Derivatives, Settled [(1)] Recognized in Earnings — For the three months ended June 30, 2016	2015	For the six months ended June 30, 2016	2015
		(in millions)			
Fixed price swaps	Gain (Loss) on Derivatives	**$ 12**	$ 52	**$ 16**	$ 94
Purchased put options	Gain (Loss) on Derivatives	**11**	–	**11**	–
Basis swaps	Gain (Loss) on Derivatives	**–**	–	**4**	(6)
Interest rate swaps	Gain (Loss) on Derivatives	**–**	(1)	**(1)**	(2)
Total gain on settled derivatives [(2)]		**$ 23**	$ 51	**$ 30**	$ 86
Total gain (loss) on derivatives		**$ (85)**	$ 1	**$ (99)**	$ 15

(1) The Company calculates gain (loss) on derivatives, settled, as the summation of gains and losses on positions that have settled within the period.

(2) Excluding interest rate swaps, these amounts are included, along with gas sales revenues, in the calculation of the Company's realized natural gas price.

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. Accounting guidance for qualifying hedges allows an unsettled derivative's unrealized gains and losses to be recorded either in 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 June 30, 2016, the Company did not have any positions designated for hedge accounting treatment. In 2015, the Company had certain fixed price swaps that were designated for hedge accounting. For the three and six months ended June 30, 2015, the Company reported a loss in other comprehensive income of $3 million (pre-tax) and a gain in other comprehensive income of $21 million (pre-tax), respectively, related to the effective portion of our unsettled fixed price swaps. The ineffective portion of those fixed price swaps was recognized in earnings and had an inconsequential impact to the unaudited condensed consolidated statement of operations for the three and six months ended June 30, 2015. For the three and six months ended June 30, 2015, a gain of $53 million (pre-tax) and a gain of $95 million (pre-tax), respectively, on settled fixed price swaps was transferred from other comprehensive income into gas sales revenues in the consolidated statements of operations.

(8) 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 six months ended June 30, 2016:

	June 30, 2016		
	Pension and Other Postretirement	Foreign Currency	Total
	(in millions) [1]		
Beginning balance at December 31, 2015	$ (25)	$ (23)	$ (48)
Other comprehensive income before reclassifications	4	3	7
Amounts reclassified from/to other comprehensive income (loss) [2]	–	–	–
Net current-period other comprehensive income (loss)	4	3	7
Ending balance at June 30, 2016	**$ (21)**	**$ (20)**	**$ (41)**

(1) All amounts are net of tax.

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

Details about Accumulated Other Comprehensive Income	Affected Line Item in the Consolidated Statement of Operations	Amount Reclassified from Accumulated Other Comprehensive Income
		For the six months ended June 30, 2016
		(in millions)
Pension and other postretirement		
Amortization of prior service cost and net loss [1]	General and administrative expenses	$ 1
	Provision (benefit) for income taxes	1
Total reclassifications for the period	Net loss	$ –

(1) See Note 12 for additional details regarding the Company's retirement and employee benefit plans.

(9) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of June 30, 2016 and December 31, 2015 were as follows:

	June 30, 2016		December 31, 2015	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(in millions)			
Cash and cash equivalents	**$ 998**	**$ 998**	$ 15	$ 15
Credit facility	**–**	**–**	116	116
Term loan facility due 2018	**744**	**744**	747	747
Term loan facility due 2020	**1,180**	**1,180**	–	–
Senior notes	**3,844**	**3,580**	3,842	2,651
Derivative instruments, net	**(131)**	**(131)**	(2)	(2)

The carrying values of cash and cash equivalents, accounts receivable, accounts payable, other current assets and 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 unsecured revolving credit and term loan facilities 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.

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 June 30, 2016 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 sold 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):

	June 30, 2016			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Assets (Liabilities) at Fair Value**
Fixed price swap assets	$ –	$ 1	$ –	$ 1
Two-way costless collars assets	–	–	12	12
Three-way costless collars assets	–	–	4	4
Basis swap assets	–	–	7	7
Fixed price swap liabilities	–	(41)	–	(41)
Two-way costless collars liabilities	–	–	(17)	(17)
Three-way costless collars liabilities	–	–	(6)	(6)
Basis swap liabilities	–	–	(8)	(8)
Sold call option liabilities	–	–	(75)	(75)
Interest rate swap liabilities	–	(8)	–	(8)
Total	$ –	$ (48)	$ (83)	$ (131)

	December 31, 2015			
	Fair Value Measurements Using:			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) at Fair Value
Basis swap assets	$ –	$ –	$ 3	$ 3
Interest rate swap liabilities	–	(5)	–	(5)
Total	$ –	$ (5)	$ 3	$ (2)

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 six months ended June 30, 2016 and 2015. 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 June 30, 2016 and 2015.

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	(in millions)			
Balance at beginning of period	**$ (35)**	$ (8)	**$ 3**	$ (8)
Total gains (losses):				
Included in earnings	**(37)**	3	**(71)**	(3)
Purchases, issuances, and settlements:				
Settlements	**(11)**	–	**(15)**	6
Transfers into/out of Level 3	**–**	–	**–**	–
Balance at end of period	**$ (83)**	$ (5)	**$ (83)**	$ (5)
Change in gains (losses) included in earnings relating to derivatives still held as of June 30	**$ (48)**	$ 3	**$ (86)**	$ 3

(10) DEBT

The components of debt as of June 30, 2016 and December 31, 2015 consisted of the following:

	June 30, 2016			
	Debt Instrument	**Unamortized Issuance Cost**	**Unamortized Debt Discount**	**Total**
	(in millions)			
Short-term debt:				
7.15% Senior Notes due June 2018	**$ 1**	**$ –**	**$ –**	**$ 1**
Total short-term debt	**$ 1**	**$ –**	**$ –**	**$ 1**
Long-term debt:				
Variable rate (2.930% at June 30, 2016) term loan facility, due November 2018 (1)	**750**	**(6)**	**–**	**744**
Variable rate (2.940% at June 30, 2016) term loan facility, due December 2020	**1,191**	**(11)**	**–**	**1,180**
7.35% Senior Notes due October 2017	**15**	**–**	**–**	**15**
7.125% Senior Notes due October 2017	**25**	**–**	**–**	**25**
3.3% Senior Notes due January 2018 (2)	**350**	**(1)**	**–**	**349**
7.5% Senior Notes due February 2018 (2)	**600**	**(1)**	**–**	**599**
7.15% Senior Notes due June 2018	**25**	**–**	**–**	**25**
4.05% Senior Notes due January 2020 (2)	**850**	**(5)**	**–**	**845**
4.10% Senior Notes due March 2022	**1,000**	**(5)**	**(1)**	**994**
4.95% Senior Notes due January 2025	**1,000**	**(7)**	**(2)**	**991**
Total long-term debt	**$ 5,806**	**$ (36)**	**$ (3)**	**$ 5,767**
Total debt	**$ 5,807**	**$ (36)**	**$ (3)**	**$ 5,768**

	December 31, 2015			
	Debt Instrument	Unamortized Issuance Cost	Unamortized Debt Discount	Total
	(in millions)			
Short-term debt:				
7.15% Senior Notes due June 2018	$ 1	$ –	$ –	$ 1
Total short-term debt	$ 1	$ –	$ –	$ 1
Long-term debt:				
Variable rate (1.886% at December 31, 2015) credit facility, expires December 2018	116	–	–	116
Variable rate (1.775% at December 31, 2015) term loan facility, due November 2018 (1)	750	(3)	–	747
7.35% Senior Notes due October 2017	15	–	–	15
7.125% Senior Notes due October 2017	25	–	–	25
3.3% Senior Notes due January 2018 (2)	350	(2)	–	348
7.5% Senior Notes due February 2018 (2)	600	(2)	–	598
7.15% Senior Notes due June 2018	26	–	–	26
4.05% Senior Notes due January 2020 (2)	850	(5)	(1)	844
4.10% Senior Notes due March 2022	1,000	(5)	(1)	994
4.95% Senior Notes due January 2025	1,000	(7)	(2)	991
Total long-term debt	$ 4,732	$ (24)	$ (4)	$ 4,704
Total debt	$ 4,733	$ (24)	$ (4)	$ 4,705

(1) In July 2016, $375 million was repaid on the term loan facility, extending the maturity from November 2018 to December 2020.

(2) In July 2016, the Company purchased approximately $312 million of the 3.3% Senior Notes due January 2018 and $388 million of the 7.5% Senior Notes due February 2018.

2016 Credit Facility

In June 2016, the Company reduced its existing $2.0 billion unsecured revolving credit facility down 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 $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 June 30, 2016, there were no borrowings under either revolving credit facility, however, there was $169 million in letters of credit 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 rate on the term loan facility is determined based upon the Company’s public debt ratings and was 250.0 basis points over the London Interbank Offered Rate (“LIBOR”) as of June 30, 2016.

The new term loan and revolving credit facility contains financial covenants that impose certain restrictions on the Company. Under the 2016 credit facility, the Company must keep a minimum interest coverage of 0.75x in 2016, increasing by 0.25x increments to 1.50x in 2019 and 2020. The Company is also subject to a minimum liquidity requirement of $300 million, which could be increased up to $500 million upon certain conditions, as well as an anti-hoarding provision, requiring unrestricted cash in excess of $100 million to pay down any amounts borrowed under the new revolving credit facility. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX 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 restructuring costs. Collateral for the new secured term loan is principally E&P properties in the Fayetteville Shale area. This collateral also may support all or a part of revolving credit extensions depending on restrictions in the Company’s senior notes indentures and requires a minimum collateral coverage ratio of 1.50x.

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.

As of June 30, 2016, the Company was in compliance with all of the covenants of the term loan and revolving credit facilities. 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 and oil.

2013 Credit Facility

In December 2013, we entered into a credit agreement that exchanged our previous revolving credit facility. Under the revolving credit facility, we had a borrowing capacity of $2.0 billion. The revolving credit facility was unsecured and was not guaranteed by any of our 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 June 30, 2016, there were no borrowings under this facility.

2015 Term Facility

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. The interest rate on the term loan facility is determined based upon the Company's public debt ratings from Moody's and S&P and was 250.0 basis points over LIBOR as of June 30, 2016. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business. In June 2016, the 2015 term loan agreement was amended to extend the maturity date upon a repayment threshold. As a result of the July 2016 equity offering, the Company repaid $375 million of the $750 million term loan, which had the effect of extending the term loan maturity from November 2018 to December 2020.

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 proceeds from this offering were used to repay the remaining principal and interest outstanding under the Company's $4.5 billion 364-day bridge term loan facility, which was first reduced with proceeds from the Company's concurrent underwritten public offerings of common and preferred stock, and were also used to repay a portion of amounts outstanding under the Company's revolving credit facility. As a result of this repayment, the Company expensed $47 million of short-term unamortized debt issuance costs related to the bridge facility in January 2015 recognized in other interest charges on the unaudited condensed consolidated statement of operations for the three months ended March 31, 2015. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. 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 25.0 basis points per downgrade level 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 175.0 basis points effective July 2016. The first higher interest rate coupon payment to bondholders will be paid in January 2017. On July 20, 2016, the Company used a portion of the proceeds from the July 2016 equity offering 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.

(11) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

As of June 30, 2016, 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 $8.6 billion, $3.3 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. The Company also had guarantee obligations of up to $861 million of that amount. As of June 30, 2016, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
	(in millions)					
Infrastructure Currently in Service	**$ 5,243**	$ 561	$ 1,136	$ 883	$ 852	$ 1,811
Pending Regulatory Approval and/or Construction (1)	**3,338**	13	231	452	672	1,970
Total Transportation Charges	**$ 8,581**	$ 574	$ 1,367	$ 1,335	$ 1,524	$ 3,781

(1) Based on the estimated in-service dates as of June 30, 2016.

In March 2010, the Company successfully bid for exclusive licenses from the Department of Natural Resources of New Brunswick to search and conduct an exploration program covering 2,518,518 net acres in the province in order to test new hydrocarbon basins. In 2015, the provincial government in New Brunswick announced a moratorium on hydraulic fracturing until it is satisfied with a list of conditions. In response to this moratorium, the Company requested and was granted an extension of its licenses to March 2021. In May 2016, the provincial government announced that the moratorium would continue in effect indefinitely. Unless and until the moratorium is lifted, Southwestern will not be able to continue with its program in New Brunswick, and given this development the Company has recognized an impairment of $39 million, net of tax, associated with its investment in New Brunswick in the second quarter of 2016.

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, and pollution, contamination or nuisance. Management believes that such 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. 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. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on the Company's financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated.

Berry-Helfand (Tovah Energy)

In February 2009, one of the Company's subsidiaries was added as a defendant in a case then styled Tovah Energy, LLC and Toby Berry-Helfand v. David Michael Grimes, et, al., then pending in the 273rd District Court in Shelby County, Texas. The plaintiff alleged that the subsidiary used information provided by the plaintiff under a confidentiality agreement, which she claimed, among other things, breached the agreement and constituted a misappropriation of a trade secret. Following a trial in December 2010, the court awarded approximately $11 million in actual damages and approximately $24 million in disgorgement of profits. Both sides appealed, and in July 2013 the Texas Court of Appeals for the Twelfth District reversed on all claims except misappropriation of trade secrets, reduced the judgment to the actual damages award and ordered the case remanded for an award of attorneys' fees to the Company's subsidiary on one of the claims on which judgment was reversed. Both parties petitioned the Supreme Court of Texas for review. On June 10, 2016, the Supreme Court ruled that insufficient evidence supported the damage award and remanded the case for a new trial. The date for the new trial has not yet been set.

The Company's subsidiary continues to deny that it breached any obligation or misappropriated any trade secret, the only two remaining claims. Based on the Company's understanding and judgment of the facts and merits of this case, and after considering the advice of counsel, the Company has determined that, although reasonably possible, a materially adverse final outcome to this action is not probable. As such, the Company has not accrued any amounts with respect to this action. The Company's assessment may change in the future depending on further court proceedings, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

Arkansas Royalty Litigation

Certain of the Company's subsidiaries are defendants in three cases, two filed in Arkansas state court in 2010 and 2013 and one in federal court in 2014, on behalf of putative classes of royalty owners on some of the Company's leases located in Arkansas. The chief complaint in all three cases is that one of the Company's subsidiaries underpaid the royalty owners by, among other things, deducting from royalty payments costs for gathering, transportation, and compression of natural gas in excess of what is permitted by the relevant leases. In September and October 2014, the judges in the two Arkansas state actions entered orders certifying classes of royalty owners who are citizens of Arkansas. The Company's subsidiaries have appealed those orders. Oral argument has not yet been set in either case.

On November 17, 2015, the court in the federal case denied the plaintiff's motion to certify a class of royalty owners not included in either of the two state cases. On April 11, 2016, the court certified a broader class that includes Arkansas residents and citizens. The plaintiff in the federal case presented two alternative damages theories. Under one theory, plaintiffs have asserted that obligations to affiliates are not "incurred" and therefore the exploration and production subsidiary was not entitled to deduct any post-production costs; the federal court has granted partial summary judgment for the Company's subsidiaries on this theory. Under another theory, plaintiffs assert that the gathering and treating rates the Company deducted from royalty payments exceeded the affiliates' actual costs or otherwise were not reasonable. The plaintiffs have not disclosed a specific damage calculation for any putative class, but based on the class representative's disclosure regarding the calculation of claimed damages, class-wide damages could exceed $100 million. Although trial previously was set for March 15, 2016, following transfer to a different judge and the certification of the class described above, that trial date has been vacated and no new date set.

In addition, in September 2015 three cases were filed in Arkansas state court on behalf of a total of 248 individually named plaintiffs. Each case asserts complaints that are in substance virtually identical to the above-described case. The Company and its subsidiaries have removed two of the cases to federal court, and those cases have been assigned to the court in which the above-described federal case is pending. All three cases have been stayed.

Management believes that, in all of the above cases, the deductions from royalty payments as calculated are permitted and intends to defend the cases vigorously. The Company's assessment may change in the future due to the occurrence of certain events, such as adverse judgments, and such a re-assessment could lead to the determination that the potential liability is probable and could be material to the Company's results of operations, financial position or cash flows.

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 liability has been recognized in connection with these indemnifications.

(12) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has 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 six months ended June 30, 2016 and 2015:

	Pension Benefits			
	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	(in millions)			
Service cost	**$ 2**	$ 4	**$ 6**	$ 8
Interest cost	**1**	2	**3**	3
Expected return on plan assets	**(1)**	(2)	**(3)**	(4)
Amortization of prior service cost	**–**	–	**–**	–
Amortization of net loss	**1**	–	**1**	1
Curtailment loss	**1**	–	**1**	–
Settlement loss	**8**	–	**8**	–
Net periodic benefit cost	**$ 12**	$ 4	**$ 16**	$ 8

In January 2016, the Company initiated a reduction in workforce that was effectively completed by the end of the first quarter. As a result of the workforce reduction, the Company recognized a $1 million non-cash curtailment loss related to its pension plan for both the curtailment-related decrease to the benefit obligation and the recognition of the proportionate share of unrecognized prior service cost and net loss from other comprehensive income (loss) in the second quarter of 2016. Additionally, the Company recognized a non-cash settlement loss of $8 million related to $28 million of lump sum payments from the pension plan in the second quarter of 2016. The Company expects pension settlements related to the reduction in workforce to be substantially complete by the end of the third quarter.

The Company's other postretirement benefit plan had a net periodic benefit cost (gain) of ($6), $1, ($5) and $2 million for the three months ended June 30, 2016 and 2015 and six months ended June 30, 2016 and 2015, respectively. Included in the net periodic benefit cost for the second quarter is a curtailment gain of $6 million, which more than offset the other components of net periodic benefit cost for the three and six months ended June 30, 2016.

As of June 30, 2016, the Company has contributed $6 million to the pension and other postretirement benefit plans. The Company expects to contribute an additional $5 million during the remainder of 2016. The Company recognized a liability of $40 million and $12 million related to its pension and other postretirement benefits, respectively, as of June 30, 2016 compared to a liability of $31 million and $20 million as of December 31, 2015. The Company updated the discount rate 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 an assumption of 4.60% from January 1, 2016 to March 31, 2016 for both the pension and other postretirement benefit plans.

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 plan. Shares of the Company's common stock purchased under the terms of the Non-Qualified Plan are presented as treasury stock and totaled 31,269 shares at June 30, 2016, compared to 47,149 shares at December 31, 2015.

(13) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and six months ended June 30, 2016 and 2015:

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	(in millions)			
Stock-based compensation cost – expensed (1) (2)	**$ 14**	$ 6	**$ 37**	$ 12
Stock-based compensation cost – capitalized	**$ 2**	$ 6	**$ 5**	$ 11

(1) Includes $2 million and $16 million related to the reduction in workforce for the three and six months ended June 30, 2016, respectively.

(2) Includes $3 million related to executive management restructuring for the three and six months ended June 30, 2016.

In January 2016, the Company announced a 40% workforce reduction that was substantially concluded 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 outstanding equity awards that modified forfeiture provisions on separation from the Company. As a result, 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.

As of June 30, 2016, 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 six months ended June 30, 2016 and provides information for options outstanding and options exercisable as of June 30, 2016:

	Number of Options (in thousands)	Weighted Average Exercise Price (per share)
Outstanding at December 31, 2015	5,623	$ 24.57
Granted	156	8.60
Exercised	–	–
Forfeited or expired	(29)	37.71
Outstanding at June 30, 2016	**5,750**	**24.07**
Exercisable at June 30, 2016	**2,611**	**$ 35.95**

Restricted Stock

The following table summarizes restricted stock activity for the six months ended June 30, 2016 and provides information for unvested shares as of June 30, 2016:

	Number of Shares (in thousands)	Weighted Average Fair Value (per share)
Unvested shares at December 31, 2015	7,222	$ 13.24
Granted	77	8.35
Vested [(1)]	(2,462)	9.22
Forfeited	(89)	11.64
Unvested shares at June 30, 2016	**4,748**	**$ 12.89**

(1) Includes 1,987,379 shares related to the reduction in workforce and 151,575 shares related to the executive management restructuring for the six months ended June 30, 2016.

Equity-Classified Performance Units

The following table summarizes performance unit activity to be paid out in Company stock for the six months ended June 30, 2016 and provides information for unvested units as of June 30, 2016. The performance units awarded in 2013 and 2014 include 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 of the performance units is based on a Monte Carlo model and is amortized to compensation expense on a straight-line basis over the vesting period of the award. The fair value of the PVI performance condition of the performance units is based on economic analysis for each investment opportunity based upon the expected present value added for each dollar to be invested and amortized to compensation expense on a straight-line basis over the vesting period of the award. The performance units awarded in 2016 and 2015 are 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, 2015	407	$ 36.65
Granted	1,502	8.60
Vested [(2)]	(412)	7.61
Forfeited [(3)]	(267)	11.13
Unvested units at June 30, 2016	**1,230**	**$ 13.69**

(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 contingent upon the actual performance against the applicable Performance Measures.

(2) Includes 13,669 units and 37,590 units related to the reduction in workforce and executive management restructuring, respectively, for the six months ended June 30, 2016.

(3) Includes 71,157 units and 195,834 units related to the reduction in workforce and executive management restructuring, respectively, for the six months ended June 30, 2016.

Liability-Classified Performance Units

Prior to 2013, certain employees were provided performance units vesting equally over three years, payable 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 under these performance unit agreements.

(14) 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 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 2015 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, and other income (loss). The "Other" column includes items not related to the Company's reportable segments including real estate and corporate items.

	Exploration and Production	Midstream	Other	Total
	(in millions)			
Three months ended June 30, 2016:				
Revenues from external customers	**$ 291**	**$ 231**	**$ –**	**$ 522**
Intersegment revenues	**(7)**	**328**	**–**	**321**
Depreciation, depletion and amortization expense	**90**	**17**	**–**	**107**
Impairment of natural gas and oil properties	**470**	**–**	**–**	**470**
Operating income (loss)	**(549)** [1]	**57**	**–**	**(492)**
Interest expense [3]	**16**	**1**	**–**	**17**
Other income (loss), net	**3**	**(2)**	**(1)**	**–**
Loss on derivatives	**(85)**	**–**	**–**	**(85)**
Benefit for income taxes [3]	**(1)**	**–**	**–**	**(1)**
Assets	**5,000**	**1,227**	**1,150** [4]	**7,377**
Capital investments [5]	**73**	**–**	**1**	**74**
Three months ended June 30, 2015:				
Revenues from external customers	$ 496	$ 267	$ 1	$ 764
Intersegment revenues	(6)	499	(1)	492
Depreciation, depletion and amortization expense	291	17	–	308
Impairment of natural gas and oil properties	1,535	–	–	1,535
Operating income (loss)	(1,639)	355	–	(1,284)
Interest expense [3]	–	–	1	1
Other income, net	3	–	–	3
Gain (loss) on derivatives	2	–	(1)	1
Provision (benefit) for income taxes [3]	(630)	138	(1)	(493)
Assets	11,882	1,352	246	13,480
Capital investments [5]	389	19	7	415

	Exploration and Production	Midstream	Other	Total
		(in millions)		
Six months ended June 30, 2016:				
Revenues from external customers	**$ 634**	**$ 467**	**$ –**	**$ 1,101**
Intersegment revenues	**(14)**	**713**	**–**	**699**
Depreciation, depletion and amortization expense	**217**	**33**	**–**	**250**
Impairment of natural gas and oil properties	**1,504**	**–**	**–**	**1,504**
Operating income (loss)	**(1,709)** [(1)]	**117** [(2)]	**–**	**(1,592)**
Interest expense [(3)]	**30**	**1**	**–**	**31**
Other income (loss), net	**1**	**(3)**	**(1)**	**(3)**
Loss on derivatives	**(98)**	**(1)**	**–**	**(99)**
Assets	**5,000**	**1,227**	**1,150** [(4)]	**7,377**
Capital investments [(5)]	**193**	**2**	**1**	**196**
Six months ended June 30, 2015:				
Revenues from external customers	$ 1,156	$ 540	$ 1	$ 1,697
Intersegment revenues	(11)	1,164	–	1,153
Depreciation, depletion and amortization expense	569	32	–	601
Impairment of natural gas and oil properties	1,535	–	–	1,535
Operating income (loss)	(1,561)	443	(1)	(1,119)
Interest expense [(3)]	45	7	–	52
Other income, net	2	–	–	2
Gain (loss) on derivatives	17	–	(2)	15
Provision (benefit) for income taxes [(3)]	(612)	169	(1)	(444)
Assets	11,882	1,352	246	13,480
Capital investments [(5)]	1,419	157	10	1,586

(1) Operating income (loss) for the E&P segment includes $11 million and $72 million related to restructuring charges for the three and six months ended June 30, 2016, respectively.

(2) Operating income (loss) for the Midstream segment includes $3 million related to restructuring charges for the six months ended June 30, 2016.

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

(4) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments. At June 30, 2016, other assets includes approximately $986 million in marketable securities.

(5) Capital investments includes a $27 million increase and an $11 million decrease for the three months ended June 30, 2016 and 2015, respectively, and decreases of $51 million and $11 million for the six months ended June 30, 2016 and 2015, respectively, relating to the change in accrued expenditures between periods. E&P capital for the three month period ended June 30, 2015 includes approximately $516 million related to the WPX Property and Statoil Property Acquisitions. Midstream capital for the six months ended June 30, 2015 includes approximately $119 million associated with the intangible asset related to the firm transportation acquired through the WPX Property Acquisition.

Included in intersegment revenues of the Midstream segment are $267 million and $419 million for the three months ended June 30, 2016 and 2015, respectively, and $586 million and $995 million for the six months ended June 30, 2016 and 2015, 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.

(15) INCOME TAXES

The Company's effective tax rate was approximately zero for the three and six months ended June 30, 2016, primarily as a result of the recognition 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 asset 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.

Due to the material write-downs of the carrying value of natural gas and oil properties and operating results, the Company is in a net deferred tax asset position. The Company believes it is more likely than not that these deferred tax assets will not be realized and recorded a $216 million and $647 million tax expense for the increase in our valuation allowance for the three and six months ended June 30, 2016, 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. A significant piece of objective negative evidence evaluated is the projected cumulative loss incurred over the three-year period ending December 31, 2016. Such objective negative evidence limits the ability to consider other subjective positive evidence, such as projections for future growth. The amount of the deferred tax asset considered realizable, however, could be adjusted if estimates of future taxable income are reduced or 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.

(16) NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Standards Implemented

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-03"), in an effort to simplify presentation of debt issuance costs. Update 2015-03 required that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs was not affected by the amendments in this Update. Entities were required to apply the amendments in Update 2015-03 on a retrospective basis, with the balance sheet of each individual period presented adjusted to reflect the period-specific effects of applying the new guidance. In August 2015, the FASB issued Accounting Standards Update No. 2015-15, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-15"), which addressed the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, given the absence of authoritative guidance within Update 2015-03 for debt issuance costs related to line-of-credit arrangements. For public entities, Update 2015-03 and Update 2015-15 were effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company adopted this update in the first quarter of 2016 resulting in an immaterial impact on its unaudited condensed consolidated results of operations, financial position and cash flows. At December 31, 2015, the Company had $24 million in unamortized debt expense that was classified as a long-term asset which is now presented as a contra liability as a result of adoption.

In May 2015, the FASB issued Accounting Standards Update No. 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (Or Its Equivalent) ("Update 2015-07"), which amends ASC 820, Fair Value Measurement. The standard removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share practical expedient and removes certain related disclosure requirements. The amendments in Update 2015-07 are effective for reporting periods beginning after December 15, 2015, with early adoption permitted. The Company adopted this update in the first quarter of 2016 resulting in no impact on its unaudited condensed consolidated results of operations, financial position and cash flows.

In September 2015, the FASB issued Accounting Standards Update No. 2015-16, Business Combinations (Topic 805) ("Update 2015-16"), which seeks to reduce the complexity of amounts recognized in a business combination. The amendments in Update 2015-16 require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in Update 2015-16 require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in Update 2015-16 require an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. The amendments in Update 2015-16 were effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The Company adopted this update in the first quarter of 2016 resulting in no impact on its unaudited condensed consolidated results of operations, financial position and cash flows.

In November 2014, the FASB issued Accounting Standards Update No. 2014-16, Derivatives and Hedging – Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity (Subtopic 815-15) ("Update 2014-16"), addresses diversity in practice related to the determination of whether derivative features embedded in hybrid instruments issued in the form of a share should be bifurcated and accounted for separately. For public entities, Update 2014-16 was effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company adopted this update in the first quarter of 2016 resulting in no impact on its unaudited condensed consolidated results of operations, financial position and cash flows.

New Accounting Standards Not Yet Implemented

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. Topic 606 Revenue from Contracts with Customers will supersede the revenue recognition requirement as in Topic 605 Revenue Recognition. Update 2014-09 requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to those goods or services. Entities may apply the amendments in Update 2014-09 either (a) retrospectively to each reporting period presented, and the entity may elect a practical expedient per the update, or (b) retrospectively with the cumulative effect of initially applying Update 2014-09 recognized at the date of initial application – if an entity elects this transition method it also should provide the additional disclosures in reporting periods. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Revenue from Contracts with Customers (Topic 606) ("Update 2015-14"). Deferral of the Effective Date, which finalized proposed ASU No. 2015-240 of the same name and responds to stakeholders' request to defer the effective date of the guidance in ASU No. 2014-09. In March 2016, the FASB issued Accounting Standards Update No. 2016-08, Revenue from Contracts with Customers (Topic 606) – Principal versus Agent Considerations (Reporting Revenue Gross versus Net) ("Update 2016-08"), which finalized proposed ASU No. 2015-290 of the same name and clarifies the implementation guidance on principal versus agent considerations. In April 2016, the FASB issued Accounting Standards Update No. 2016-10, Revenue from Contracts with Customers (Topic 606) ("Update 2016-10"), which clarifies multiple aspects of Topic 606. In May 2016, the FASB issued Accounting Standards Update No. 2016-12, Revenue from Contracts with Customers (Topic 606) – Narrow-Scope Improvements and Practical Expedients ("Update 2016-12"), which provides clarifying guidance in a few narrow areas and adds some practical expedients to the guidance. For public entities, Update 2014-09, Update 2015-14, Update 2016-08, Update 2016-10 and Update 2016-12 are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2014-09, Update 2015-14, Update 2016-08, Update 2016-10 and Update 2016-12 and assessing the impact, if any, they may have on its consolidated results of operations, financial position or cash flows.

In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Inventory (Topic 330) ("Update 2015-11"), which seeks to simplify the measurement of inventory. Update 2015-11 requires that an entity should measure inventory at the lower of cost and net realizable value, where net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. For public entities, the amendments in Update 2015-11 are effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2015-11 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

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. 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. The Company is currently evaluating the provisions of Update 2016-02 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Compensation - Stock Compensation (Topic 718) ("Update 2016-09"), which seeks 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 becomes effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of Update 2016-09 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

(17) SUBSEQUENT EVENTS

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, after underwriting discount and offering expenses, from the common stock offering were approximately $1,247 million. 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.

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 2015 Annual Report and analyzes the changes in the results of operations between the three and six months ended June 30, 2016 and 2015. 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 2015 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 the "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 2015 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" or "Southwestern") is an independent energy company engaged in natural gas and oil 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." We conduct most of our businesses through subsidiaries and we operate principally in two segments: E&P and Midstream.

Exploration and Production. Our primary business is the exploration for and production of natural gas and oil, 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. Collectively, we refer to our properties located in Pennsylvania and West Virginia as the "Appalachian Basin." Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale. We have exploration and production activities ongoing in Colorado and Louisiana, along with other areas in which we are currently exploring for new development opportunities. We also have drilling rigs located in Pennsylvania, West Virginia and Arkansas and provide oilfield products and services, principally serving our E&P operations.

Midstream. 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 the natural gas, oil and NGLs produced in our E&P operations.

We are focused on providing long-term growth in the net asset value per share of our business. Historically, the vast majority of our operating income and cash flow has been derived from the production associated with our E&P business. However, in 2015 and the first half of 2016, depressed commodity prices significantly decreased our E&P results of operations. The price we expect to receive for our production is a critical factor in the capital investments we make to develop our properties. In the fourth quarter of 2015, we decreased activity in the Appalachian Basin and the Fayetteville Shale as a result of the lower commodity price environment. Based on current forward pricing, along with the successful implementation of our debt reduction strategy, we expect to begin increasing our activity in the third quarter of 2016, continuing throughout the remainder of the year. Natural gas prices fluctuate due to a variety of factors we cannot control or predict. These factors, which include increased supplies of natural gas due to greater exploration and development activities, weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sales prices for our production. We are impacted by crude oil and NGL prices, which have been volatile and have recently declined significantly. In addition to the factors identified above, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices, including basis differentials. Current 2016 forward pricing will likely result in additional impairments to our natural gas and oil properties in the third quarter of 2016 ranging from approximately $450 million to $600 million, net of taxes, including changes in costs excluded from amortization related to the recently announced divestitures and excluding other such changes, with material impairments possible beyond the third quarter.

Three Months Ended June 30, 2016 Compared with Three Months Ended June 30, 2015

We reported a net loss attributable to common stock of $620 million for the three months ended June 30, 2016, or ($1.61) per diluted share, compared to net loss attributable to common stock of $815 million, or ($2.13) per diluted share, for the three months ended June 30, 2015.

Our natural gas and liquids production decreased to 225 Bcfe for the three months ended June 30, 2016, down 8% from 245 Bcfe for the three months ended June 30, 2015. The 20 Bcfe decrease was due to a 26 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by 3 Bcfe increases in net production from each of our Northeast and Southwest Appalachia properties, respectively. The average price realized for our gas production, including the effects of derivatives, decreased 41% to $1.32 per Mcf for the three months ended June 30, 2016, compared to $2.23 per Mcf for the same period in 2015. The average price realized for our oil production decreased 21% to $32.46 per barrel for the three months ended June 30, 2016, compared to $40.88 per barrel for the same period in 2015. The average price realized for our NGL production increased 11% to $6.41 per barrel for the three months ended June 30, 2016, compared to $5.77 per barrel for the same period in 2015. We did not financially protect our 2016 or 2015 oil or NGL production.

Our E&P segment reported an operating loss of $549 million for the three months ended June 30, 2016, down from an operating loss of $1,639 million for the three months ended June 30, 2015. This decrease was primarily due to the decrease in the impairment of natural gas and oil properties to $470 million for the three months ended June 30, 2016, as compared to the $1,535 million impairment recorded for the same period in 2015. Excluding impairments, our E&P segment reported an operating loss of $79 million for the three months ended June 30, 2016, compared to an operating loss of $104 million for the same period in 2015, primarily due to a $231 million decrease in operating costs and expenses and an increase in our realized NGL price, partially offset by a 41%, or $0.91 per Mcf, decrease in our realized natural gas price (including derivatives), a 20 Bcfe decrease in production and a decrease in our realized oil price from the same period in 2015. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for a $1 million operating loss for the three months ended June 30, 2015.

Operating income for our Midstream segment was $57 million for the three months ended June 30, 2016, down from $355 million for the three months ended June 30, 2015, primarily due to a $278 million gain on sale of assets, net in 2015. Excluding the net gain on sale, our Midstream segment operating income decreased $20 million due to a $28 million decrease in gas gathering revenues and a $7 million decrease in our marketing margin, partially offset by a $15 million decrease in operating costs and expenses. In the second quarter of 2015, we sold our northeastern Pennsylvania and East Texas gathering assets that accounted for less than $1 million in operating income for the three months ended June 30, 2015. A net gain on these sales of $278 million was recognized and is included in gain on sale of assets, net in the unaudited condensed consolidating statement of operations.

Capital investments were $74 million for the three months ended June 30, 2016 (including $41 million in capitalized interest and $20 million in capitalized expenses), of which $73 million was invested in our E&P segment, compared to $415 million for the same period of 2015, of which $389 million was invested in our E&P segment.

Six Months Ended June 30, 2016 Compared with Six Months Ended June 30, 2015

We reported a net loss attributable to common stock of $1.8 billion for the six months ended June 30, 2016, or ($4.63) per diluted share, compared to net loss attributable to common stock of $762 million, or ($2.01) per diluted share, for the six months ended June 30, 2015.

Our natural gas and liquids production decreased to 462 Bcfe for the six months ended June 30, 2016, down 3% from 478 Bcfe for the six months ended June 30, 2015. The 16 Bcfe decrease was due to a 43 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by 14 Bcf and 13 Bcfe increases in net production from our Northeast and Southwest Appalachia properties, respectively. The average price realized for our gas production, including the effects of derivatives, decreased 46% to $1.40 per Mcf for the six months ended June 30, 2016, compared to $2.60 per Mcf for the same period in 2015. The average price realized for our oil production decreased 30% to $25.43 per barrel for the six months ended June 30, 2016, compared to $36.08 per barrel for the same period in 2015. The average price realized for our NGL production decreased 26% to $5.67 per barrel for the six months ended June 30, 2016, compared to $7.63 per barrel for the same period in 2015. We did not financially protect our 2016 or 2015 oil or NGL production.

Our E&P segment reported an operating loss of $1.7 billion for the six months ended June 30, 2016, up from an operating loss of $1.6 billion for the six months ended June 30, 2015. Excluding $1.5 billion of impairments of natural gas and oil properties in both 2016 and 2015, respectively, our E&P segment operating loss increased to $205 million for the six months ended June 30, 2016, primarily due to a 46%, or $1.20 per Mcf, decrease in our realized natural gas price (including derivatives), a 16 Bcfe decrease in production and decreases in our realized oil and NGL prices. These decreases were partially offset by a $346 million decrease in operating costs and expenses. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $1 million in operating income for the six months ended June 30, 2015.

Operating income for our Midstream segment was $117 million for the six months ended June 30, 2016, down from $443 million for the six months ended June 30, 2015, primarily due to a $278 million gain on sale of assets, net in 2015. Excluding the net gain on sale, our Midstream segment operating income decreased $48 million due to a $62 million decrease in gas gathering revenues and a $7 million decrease in marketing margin, partially offset by a $21 million decrease in operating costs and expenses. In the second quarter of 2015, we sold our northeastern Pennsylvania and East Texas gathering assets that accounted for $13 million in operating income for the six months ended June 30, 2015. A net gain on these sales of $278 million was recognized and is included in gain on sale of assets, net in the unaudited condensed consolidating statement of operations.

Capital investments were $196 million for the six months ended June 30, 2016 (including $82 million in capitalized interest and $41 million in capitalized expenses), of which $193 million was invested in our E&P segment, compared to $1.6 billion for the same period of 2015 (including $635 million, in total, related to the acquisitions from WPX Energy, Inc. and Statoil ASA), of which $1.4 billion was invested in our E&P segment.

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

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
Revenues (in millions)	**$ 284**	$ 490	**$ 620**	$ 1,145
Impairment of natural gas and oil properties (in millions)	**$ 470**	$ 1,535	**$ 1,504**	$ 1,535
Operating costs and expenses (in millions)	**$ 363**	$ 594	**$ 825**	$ 1,171
Operating loss (in millions)	**$ (549)**	$ (1,639)	**$ (1,709)**	$ (1,561)
Gain on derivatives, settled (in millions) (1)	**$ 23**	$ 52	**$ 31**	$ 88
Gas production (Bcf)	**203**	226	**416**	445
Oil production (MBbls)	**586**	589	**1,193**	1,134
NGL production (MBbls)	**3,136**	2,574	**6,512**	4,340
Total production (Bcfe)	**225**	245	**462**	478
Average realized gas price per Mcf, including derivatives (2)	**$ 1.32**	$ 2.23	**$ 1.40**	$ 2.60
Average realized gas price per Mcf, excluding derivatives	**$ 1.21**	$ 1.76	**$ 1.33**	$ 2.19
Average realized oil price per Bbl	**$ 32.46**	$ 40.88	**$ 25.43**	$ 36.08
Average realized NGL price per Bbl	**$ 6.41**	$ 5.77	**$ 5.67**	$ 7.63
Average unit costs per Mcfe:				
Lease operating expenses	**$ 0.87**	$ 0.93	**$ 0.88**	$ 0.93
General & administrative expenses (3)	**$ 0.21**	$ 0.21	**$ 0.20**	$ 0.22
Taxes, other than income taxes (4)	**$ 0.09**	$ 0.10	**$ 0.09**	$ 0.11
Full cost pool amortization	**$ 0.35**	$ 1.13	**$ 0.42**	$ 1.14

(1) Represents the gain on settled commodity derivatives.

(2) Includes the gain on settled commodity derivatives.

(3) Excludes $11 million and $69 million of restructuring charges for the three and six months ended June 30, 2016, respectively.

(4) Excludes $3 million of restructuring charges for the six months ended June 30, 2016.

Revenues

Revenues for our E&P segment were down $206 million, or 42%, for the three months ended June 30, 2016, compared to the same period in 2015. A decrease in the price realized from the sale of our natural gas production decreased revenue by $112 million. Additionally there was a decrease of $53 million in hedge settlement proceeds, a $41 million decrease due to lower natural gas production volumes, and a $5 million decrease as a result of decreased oil pricing, partially offset by a $5 million increase as a result of increased NGL production and pricing. E&P revenues were $620 million for the six months ended June 30, 2016, down $525 million, or 46%, compared to the same period in 2015. A decrease in the price realized from the sale of our natural gas production decreased revenue by $358 million. Additionally, there was a decrease of $95 million in hedge settlement proceeds, a $65 million decrease due to lower natural gas production volumes, and a $26 million decrease as a result of decreased liquid pricing, partially offset by a $19 million increase due to increased liquid production volumes. Natural gas, oil, and NGL prices are difficult to predict and are subject to wide price fluctuations. Excluding basis swaps, as of June 30, 2016 we had protected 90 Bcf of our remaining 2016 natural gas production to limit our exposure to price fluctuations. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report and to the discussion of "Commodity Prices" provided below for additional information. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $5 and $15 million of our natural gas and oil revenues for the three and six months ended June 30, 2015, respectively.

Production

For the three months ended June 30, 2016, our natural gas and liquids production decreased 8% to 225 Bcfe, down from 245 Bcfe from the same period in 2015, and was produced entirely by our properties in the United States. The 20 Bcfe decrease was primarily due to a 26 Bcfe decrease in net production from our Fayetteville Shale and other properties, partially offset by 3 Bcfe increases in net production from each of our Northeast and Southwest Appalachia properties, respectively. Net production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 90 Bcf, 38 Bcfe and 96 Bcf respectively, for the three months ended June 30, 2016, compared to 87 Bcf, 35 Bcfe, and 121 Bcf, respectively, for the same period in 2015. For the six months ended June 30, 2016, our natural gas and liquids production decreased 3% to 462 Bcfe, down from 478 Bcfe from the same period in 2015, and was produced entirely by our properties in the United States. The 16 Bcfe decrease was due to a 43 Bcf decrease in net production from our Fayetteville Shale and other properties, partially offset by 14 Bcf and 13 Bcfe increases in net production from our Northeast and Southwest Appalachia properties, respectively. Net production from our Northeast Appalachia, Southwest Appalachia and Fayetteville Shale properties was 184 Bcf, 78 Bcfe and 199 Bcf respectively, for the six months ended June 30, 2016 compared to 170 Bcf, 65 Bcfe, and 236 Bcf, respectively, for the same period in 2015.

Commodity Prices

The average price realized for our natural gas production, including the effects of derivatives, decreased to $1.32 per Mcf for the three months ended June 30, 2016, as compared to $2.23 per Mcf for the same period in 2015. The decrease was the result of a $0.55 per Mcf decrease in the average natural gas price, excluding derivatives, and lower proceeds from our derivative program during the three months ended June 30, 2016 as compared to the same period in 2015. The average price realized for our natural gas production, excluding the effects of derivatives, decreased 31% to $1.21 per Mcf for the three months ended June 30, 2016, as compared to the same period in 2015. Our derivatives increased the average realized natural gas price by $0.11 per Mcf for the three months ended June 30, 2016 compared to an increase of $0.47 per Mcf for the same period in 2015. The average price realized for our natural gas production, including the effects of derivatives, decreased to $1.40 per Mcf for the six months ended June 30, 2016, as compared to $2.60 per Mcf for the same period in 2015. The decrease was the result of a $0.86 per Mcf decrease in the average natural gas price, excluding derivatives, and lower proceeds from our derivative program during the six months ended June 30, 2016 as compared to the same period in 2015. The average price realized for our natural gas production, excluding the effects of derivatives, decreased 39% to $1.33 per Mcf for the six months ended June 30, 2016, as compared to the same period in 2015. Our derivatives increased the average realized natural gas price by $0.07 per Mcf for the six months ended June 30, 2016 compared to an increase of $0.41 per Mcf for the same period in 2015.

Our E&P segment receives a sales price for our natural gas at a discount to average monthly NYMEX settlement prices due to 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 discount 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.

We 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 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional discussion about our derivatives and risk management activities.

Excluding the impact of derivatives, the average price received for our natural gas production for the six months ended June 30, 2016 of $1.33 per Mcf was approximately $0.69 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 38% of our natural gas production for the six months ended June 30, 2016 from the impact of widening basis differentials through our sales arrangements and hedging activities. For the six months ended June 30, 2016, we protected the basis on approximately 152 Bcf of our natural gas production through physical sales arrangements. We have protected basis on approximately 111 Bcf and 90 Bcf of our remaining 2016 and 2017 expected natural gas production through physical sales arrangements at a basis differential to NYMEX natural gas prices of approximately ($0.16) per Mcf and ($0.12) per Mcf for the remainder of 2016 and 2017, respectively. We have also financially protected a portion our remaining 2016 and 2017 expected natural gas production. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our derivative instruments.

We realized an average sales price of $32.46 per barrel for our oil production for the three months ended June 30, 2016, down 21% from $40.88 per barrel for the same period in 2015. Oil accounted for 2% and 1% of our total production for the three months ended June 30, 2016 and 2015, respectively. We realized an average sales price of $25.43 per barrel for our oil production for the six months ended June 30, 2016, down 30% from $36.08 per barrel for the same period in 2015. Oil accounted for 2% and 1% of our total production for the six months ended June 30, 2016 and 2015, respectively. We did not financially protect our 2016 or 2015 oil production.

We realized an average sales price of $6.41 per barrel for our NGL production for the three months ended June 30, 2016, up 11% from $5.77 per barrel for the same period in 2015. NGLs accounted for 8% and 6% of our total production for the three months ended June 30, 2016 and 2015, respectively. We realized an average sales price of $5.67 per barrel for our NGL production for the six months ended June 30, 2016, down 26% from $7.63 per barrel for the same period in 2015. NGLs accounted for 8% and 6% of our total production for the six months ended June 30, 2016 and 2015, respectively. We did not financially protect our 2016 or 2015 NGL production.

Operating Income

Our E&P segment reported an operating loss of $549 million for the three months ended June 30, 2016, down from an operating loss of $1,639 million for the three months ended June 30, 2015. The E&P segment recorded a $470 million impairment of natural gas and oil properties for the three months ended June 30, 2016, compared to a $1,535 million impairment for the same period in 2015. Excluding impairments, our E&P segment reported an operating loss of $79 million for the three months ended June 30, 2016, compared to an operating loss of $104 million for the same period in 2015, primarily due to a $231 million decrease in operating costs and expenses resulting primarily from a $201 million decrease in DD&A, a $30 million decrease in operating expenses and a $4 million decrease in taxes other than income. These decreases were partially offset by a 41%, or $0.91 per Mcf, decrease in our realized natural gas price (including derivatives), a 20 Bcfe decrease in our production, a decrease in our realized oil price and a $5 million increase in general and administrative expenses. For the three months ended June 30, 2016, general and administrative expenses included $11 million related to restructuring charges.

Our E&P segment reported an operating loss of $1.7 billion for the six months ended June 30, 2016, up from an operating loss of $1.6 billion for the six months ended June 30, 2015. The E&P segment recorded $1.5 billion of impairments of natural gas and oil properties for the six months ended June 30, 2016 and 2015. Excluding impairments, our E&P segment reported an operating loss of $205 million for the six months ended June 30, 2016, primarily due to a 46%, or $1.20 per Mcf, decrease in our realized natural gas price (including derivatives), a 16 Bcfe decrease in production and decreases in our realized oil and NGL prices. These decreases were partially offset by a $346 million decrease in operating costs and expenses, resulting primarily from a $352 million decrease in DD&A, a $37 million decrease in operating expenses and an $8 million decrease in taxes other than income, partially offset by a $52 million increase in general and administrative expenses. For the six months ended June 30, 2016, general and administrative expenses and taxes other than income included $69 million and $3 million, respectively, related to restructuring charges. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that had minimal impact on our operating income (loss) for the three and six months ended June 30, 2015, respectively.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.87 for the three months ended June 30, 2016, compared to $0.93 for the same period in 2015. For the six months ended June 30, 2016, lease operating expenses decreased to $0.88, compared to $0.93 for the same period in 2015. Lease operating expenses per Mcfe decreased for the three and six months ended June 30, 2016, as compared to the same periods of 2015 primarily due to decreased workover activity and contract services as well as the successful renegotiation of our existing gathering and processing rates in Southwest Appalachia.

Excluding the restructuring charges associated primarily with our workforce reduction, general and administrative expenses for the E&P segment were $0.21 per Mcfe for the three months ended June 30, 2016 and 2015. General and administrative cost reductions were offset by decreased production volumes. In total, excluding restructuring charges, general and administrative expenses for the E&P segment were $46 million for the three months ended June 30, 2016, compared to $52 million for the three months ended June 30, 2015. Including restructuring charges, general and administrative costs for three months ended June 30, 2016 were $57 million for our E&P segment. Excluding the restructuring charges associated primarily with our workforce reduction, general and administrative expenses for the E&P segment were $0.20 per Mcfe for the six months ended June 30, 2016, compared to $0.22 per Mcfe for the same period in 2015, primarily due to the decrease in employee costs. In total, excluding restructuring charges, general and administrative expenses for the E&P segment were $91 million for the six months ended June 30, 2016, compared to $108 million for the six months ended June 30, 2015. Including restructuring charges, general and administrative costs for the six months ended June 30, 2016 were $160 million for our E&P segment.

Taxes other than income taxes per Mcfe were $0.09 for the three months ended June 30, 2016, compared to $0.10 for the same period in 2015. Taxes other than income taxes per Mcfe were $0.09 for the six months ended June 30, 2016 (excluding $3 million related to restructuring charges), compared to $0.11 for the same period in 2015. Taxes other than income taxes per Mcfe vary from period to period due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices.

Our full cost pool amortization rate averaged $0.35 per Mcfe for the three months ended June 30, 2016, compared to $1.13 per Mcfe for the same period in 2015. For the first six months of 2016, our full cost pool amortization rate averaged $0.42 per Mcfe, compared to $1.14 per Mcfe for the same period in 2015. 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 level 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.

Unevaluated costs excluded from amortization were $3.4 billion at June 30, 2016, compared to $3.7 billion at December 31, 2015. The decrease in unevaluated costs primarily resulted from our evaluation of a portion of our New Ventures assets.

Midstream

	For the three months ended June 30,		For the six months ended June 30,	
	2016	2015	**2016**	2015
	($ in millions, except volumes)			
Marketing revenues	**$ 462**	$ 641	**$ 980**	$ 1,442
Gas gathering revenues	**$ 97**	$ 125	**$ 200**	$ 262
Marketing purchases	**$ 452**	$ 624	**$ 955**	$ 1,410
Operating costs and expenses (1)	**$ 50**	$ 65	**$ 108**	$ 129
Gain on sale of assets, net	**$ –**	$ 278	**$ –**	$ 278
Operating income	**$ 57**	$ 355	**$ 117**	$ 443
Volumes marketed (Bcfe)	**271**	289	**550**	549
Volumes gathered (Bcf)	**154**	201	**318**	434

(1) Includes less than $1 million and $3 million of restructuring charges for the three and six months ended June 30, 2016, respectively.

Revenues

Revenues from our marketing activities were down 28% to $462 million for the three months ended June 30, 2016, compared to the same period in 2015, and were down 32% to $980 million for the six months ended June 30, 2016, compared to the same period in 2015. For the three months ended June 30, 2016, the price received for volumes marketed decreased 23% and the volumes marketed decreased 6%, compared to the same period in 2015. For the six months ended June 30, 2016, the price received for volumes decreased 32%. 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 94% and 96% of the natural gas marketed volumes for the three months ended June 30, 2016 and 2015, respectively. For six months ended June 30, 2016 and 2015, production from our affiliated E&P operated wells accounted for 95% and 97%, respectively, of our total natural gas volumes marketed. Our Midstream segment marketed approximately 65% and 64% of our combined oil and NGL production for the three months ended June 30, 2016 and 2015, respectively, and 66% and 54% of our combined oil and NGL production for the six months ended June 30, 2016 and 2015, respectively.

Revenues from our gathering activities were down 22% to $97 million for the three months ended June 30, 2016, compared to the same period in 2015, and down 24% to $200 million for the six months ended June 30, 2016, compared to the same period in 2015. The decrease in gathering revenues for the three and six months ended June 30, 2016 was primarily due to decreased volumes in the Fayetteville Shale and the divestiture of our northeast Pennsylvania and East Texas gathering assets in 2015. The divested gathering assets accounted for $2 million and $21 million of our gathering revenues for the three and six months ended June 30, 2015, respectively.

Operating Income

Operating income from our Midstream segment decreased to $57 million for the three months ended June 30, 2016, compared to $355 million for the same period in 2015, primarily due to a $278 million gain on sale of assets, net in 2015, related to the divestitures of our northeastern Pennsylvania and East Texas gathering assets. Excluding the net gain on sale, our Midstream segment operating income decreased 26% for the three months ended June 30, 2016 due to a $28 million decrease in gas gathering revenues and a $7 million decrease in marketing margin, partially offset by a $15 million decrease in operating costs and expenses. Operating income decreased to $117 million for the six months ended June 30, 2016, compared to $443 million for the same period in 2015, primarily due to a $278 gain on sale of assets, net in 2015. Excluding the net gain on sale, our Midstream segment operating income decreased 29% for the six months ended June 30, 2016 due to a $62 million decrease in gas gathering revenues and a $7 million decrease in marketing margin, partially offset by a $21 million decrease in operating costs and expenses. The divested northeastern Pennsylvania and East Texas gathering assets accounted for less than $1 million and $13 million of our operating income for the three and six months ended June 30, 2015, respectively.

The margin generated from marketing activities was $10 million and $17 million for the three months ended June 30, 2016 and 2015. The margin generated from gas marketing activities was $25 million and $32 million for the six months ended June 30, 2016 and 2015, 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 hedging activities 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.

Restructuring Charges

In January 2016, we announced a 40% workforce reduction that 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 $11 million and $75 million for the three and six months ended June 30, 2016, respectively.

Interest Expense

Interest expense, net of capitalization, was $17 million for the three months ended June 30, 2016, compared to $1 million for the same period in 2015, and $31 million for the six months ended June 30, 2016, compared to $52 million for the same period in 2015. Gross interest expense increased to $58 million for the three months ended June 30, 2016, compared to $55 million for the same period in 2015, primarily due to an increase in our cost of debt. For the six months ended June 30, 2016, gross interest expense increased to $113 million, up from $107 million for the six months ended June 30, 2015, excluding a $47 million charge for unamortized fees associated with the repayment of our bridge facility in the first quarter of 2015. We capitalized interest of $41 million and $54 million for the three months ended June 30, 2016 and 2015, respectively, and capitalized interest of $82 million and $102 million for the six months ended June 30, 2016 and 2015, respectively. The decrease in capitalized interest for the three and six months ended June 30, 2016, compared to the same periods in 2015, was primarily due to the evaluation of a portion of our Southwest Appalachia assets, acquired in December 2014.

Gain (Loss) on Derivatives

In general, our derivatives are not designated for hedge accounting treatment. Changes in the fair value of derivatives that are not designated for hedge accounting are recorded in gain (loss) on derivatives. We recorded an $85 million net loss on our derivatives for the three months ended June 30, 2016, consisting of a $108 million loss on unsettled derivatives, partially offset by a $23 million gain on settled derivatives. For the three months ended June 30, 2015, we recorded a $1 million net gain on our derivatives, consisting of a $51 million gain on settled derivatives, partially offset by a $50 million loss on unsettled derivatives. We recorded a $99 million net loss on our derivatives for the six months ended June 30, 2016, consisting of a $129 million loss on unsettled derivatives, partially offset by a $30 million gain on settled derivatives. For the six months ended June 30, 2015, we recorded a $15 million net gain on our derivatives, consisting of an $86 million gain on settled derivatives, partially offset by a $71 million loss on unsettled derivatives. We refer you to Note 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report for additional details about our gain (loss) on derivatives. In general and without consideration of volatility or duration, as natural gas prices increase from June 30, 2016 levels, we will recognize losses in future periods and, likewise, as natural gas prices decline from June 30, 2016 levels, we will recognize gains in future periods on our derivative contracts not accounted for under hedge accounting prior to settlement.

Income Taxes

Our effective tax rate was approximately zero and 38% for the six months ended June 30, 2016 and 2015, respectively. We recorded an income tax benefit of $1 million and $493 million for the three months ended June 30, 2016 and 2015, respectively. We recorded an income tax benefit of $444 million for the six months ended June 30, 2015. The low effective income tax rate at June 30, 2016 was 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 16 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 16 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 internally generated funds, our cash and cash equivalents balance, funds accessed through our $1,191 million term loan facility, our $809 million revolving credit facilities and capital markets as our primary sources of liquidity.

In June 2016, we took significant steps in managing our maturities and liquidity by entering into amendments of our bank credit facilities, which had the effect of extending the maturities by two years until late 2020. We also entered into a definitive agreement with a third party to sell approximately 55,000 net acres in West Virginia for $450 million. We expect this sale to be completed in the third quarter of 2016. In July 2016, we completed a public offering of 98,900,000 shares of our common stock, with net proceeds totaling approximately $1,247 million after underwriting discounts and offering expenses. Of the funds received from the common stock offering, $375 million was used to pay down a portion of our $750 million term loan entered into in November 2015, extending its maturity through 2020, and up to $750 million was reserved to fund tender offers for certain of our outstanding senior notes. On July 20, 2016, we used a portion of the proceeds from the July 2016 equity offering to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018. In addition to the $1.1 billion of debt reduction, a portion of the funds from the equity issuance and the sale of the West Virginia acreage should enable us supplement our 2016 capital budget (discussed below under "Capital Investments").

In the first half of 2016, we decreased activity in the Appalachian Basin and Fayetteville Shale as a result of the low commodity price environment. Based on current forward pricing, along with the successful implementation of our debt reduction strategy, we expect to begin increasing our activity in the third quarter of 2016, continuing throughout the remainder of the year. Although we have the financial flexibility to draw on the funds available under our revolving credit facility as necessary, we are committed to our capital discipline strategy of investing within our cash flow from operations, supplemented by the remaining funds, after debt reduction, from the July 2016 equity issuance and our recently-announced asset sale in West Virginia (discussed below under "Capital Investments"). We refer you to Note 10 of the unaudited condensed consolidated financial statements included in this Quarterly Report and the section below under "Financing Requirements" for additional discussion of our credit facilities.

At June 30, 2016, prior to the July 2016 equity offering and subsequent tender offers, our capital structure consisted of 89% net debt and 11% equity (including $998 million in cash and cash equivalents and excluding $36 million and $3 million of unamortized issuance cost and unamortized debt discount, respectively). We believe that our operating cash flow and available cash and cash equivalents along with our funds under our revolving credit facilities will be adequate to meet our capital and operating requirements for the remainder of 2016. 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 the section below under "Financing Requirements" for additional discussion of our compliance with the covenants of our term loans and revolving credit facilities.

Net cash provided by operating activities decreased 82% to $165 million for the six months ended June 30, 2016, down from $940 million for the same period in 2015, primarily due to a decrease in net income adjusted for non-cash expenses and changes in working capital accounts. During the six months ended June 30, 2016, requirements for our capital investments were funded primarily from our cash generated by operating activities, net proceeds from borrowings under our revolving credit facility, commercial paper, and cash and cash equivalents. For the six months ended June 30, 2016, net cash generated from operating activities provided 84% of our cash requirements for capital investments, compared to 59% for the same period in 2015.

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 7 to the unaudited condensed consolidated financial statements included in this Quarterly Report for further details. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete 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.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and co-owners. 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 co-owners 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 will adjust our discretionary uses of cash dependent upon available cash flow. Further, we may from time to time seek to retire or rearrange some or all of our outstanding debt or preferred stock 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.

Capital Investments

Our capital investments were $196 million and $1.6 billion for the six months ended June 30, 2016 and 2015, respectively. Capital investments for the six months ended June 30, 2015 included $635 million, in total, related to acquisitions from WPX Energy, Inc. and Statoil ASA. Our E&P segment investments were $193 million and $1.4 billion for the six months ended June 30, 2016 and 2015, respectively. Our E&P segment capitalized internal costs of $49 million for the six months ended June 30, 2016 compared to $165 million for the comparable period in 2015. 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.

The remaining funds, after debt reduction, from the equity issuance and the anticipated sale of the long-dated undeveloped West Virginia acreage should enable us to supplement our 2016 capital budget, allowing us the opportunity to complete many of our drilled but uncompleted wells and resume drilling on our high PVI projects. Although our 2016 capital investment program is expected to be funded through cash flow from operations along with our cash and cash equivalents, we have the financial flexibility to utilize borrowings under our revolving credit facilities.

Financing Requirements

Our total debt outstanding was $5.8 billion at June 30, 2016, compared to $4.7 billion at December 31, 2015. Our total debt net of cash and cash equivalents was $4.8 billion at June 30, 2016, compared to $4.7 billion at December 31, 2015. We have taken steps to reduce our total debt outstanding, which is discussed further below.

In July 2016, we consummated an underwritten offering of 98,900,000 shares of our common stock pursuant to an effective registration statement filed with the Securities and Exchange Commission, with net proceeds of the offering totaling approximately $1,247 million after underwriting discounts 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 our outstanding senior notes due in the first quarter of 2018. The remaining net proceeds of the offering will be used for general corporate purposes, including the repayment of additional indebtedness outstanding under the 2015 term loan, the completion of wells already drilled or the funding of other capital projects.

At June 30, 2016, prior to the July 2016 equity offering and subsequent tender offers, our capital structure consisted of 89% net debt and 11% equity (including $998 million in cash and cash equivalents and excluding $36 million and $3 million of unamortized issuance cost and unamortized debt discount, respectively), compared to 67% net debt and 33% equity (including $15 million in cash and cash equivalents) at December 31, 2015.

At July 19, 2016, we had a long-term issuer credit rating of Ba3 by Moody’s and a long-term debt rating of BB- by S&P. 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.

In June 2016, we reduced our existing $2.0 billion unsecured revolving credit facility down 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 unsecured $743 million revolving credit facility, which matures in December 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 June 30, 2016, there were no borrowings under either revolving credit facility; however, there was $169 million in letters of credit 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 rate on the term loan facility is determined based upon our public debt ratings and was 250.0 basis points over LIBOR as of June 30, 2016.

Our 2016 credit agreement contains financial covenants that impose certain restrictions on us. Under our revolving credit and term loan facilities, we must keep a minimum interest coverage of 0.75x in 2016, increasing by 0.25x increments to 1.50x in 2019 and 2020. We are also subject to a minimum liquidity requirement of $300 million, which could be increased up to $500 million upon certain conditions, as well as an anti-hoarding provision, requiring unrestricted cash in excess of $100 million to pay down any amounts borrowed under the new revolving credit facility. The financial covenant with respect to minimum interest coverage consists of EBITDAX divided by consolidated interest expense. EBITDAX 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 restructuring costs. Collateral for the new secured term loan is principally E&P properties in the Fayetteville Shale area. This collateral also may support all or a part of revolving credit extensions depending on restrictions in our senior notes indentures and requires a minimum collateral coverage ratio of 1.50x.

The existing unsecured 2013 revolving credit facility includes a financial covenant under which we may not issue total debt in excess of 60% of our 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 our pension and other postretirement liabilities.

As of June 30, 2016, we were in compliance with all of the covenants of the term loan 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.

In November 2015, we entered into a $750 million unsecured three-year term loan credit agreement with various lenders that was used to repay borrowings under the existing revolving credit facility. The interest rate on the term loan facility is determined based upon our public debt ratings from Moody’s and S&P and was 250 basis points over LIBOR as of June 30, 2016. The term loan facility requires prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business. In June 2016, the 2015 term loan agreement was amended to extend the maturity date, pending a certain repayment threshold. As a result of our July 2016 equity offering, we repaid $375 million of the $750 million term loan, which had the effect of extending its maturity from November 2018 to December 2020.

In January 2015, we completed concurrent underwritten public offerings of 30,000,000 shares of common stock and 34,500,000 depositary shares (both share counts include shares issued as a result of the underwriters exercising their options to purchase additional shares). Net proceeds from the offerings totaled approximately $2.3 billion after underwriting discount and expenses. Each depositary share represents a 1/20th interest in a share of our mandatory convertible preferred stock, with a liquidation preference of $1,000 per share (equivalent to a $50 liquidation preference per depositary share). The proceeds from the offerings were used to partially repay borrowings under a $4.5 billion 364-day bridge facility that we entered into in December 2014 in connection with our acquisition of assets in Southwest Appalachia, with the remaining balance fully repaid with proceeds from our January 2015 public offering of $2.2 billion in senior notes.

The mandatory convertible preferred stock entitles the holders to a proportional fractional interest in the rights and preferences of the convertible preferred stock, including conversion, dividend, liquidation and voting rights. Dividends are to be paid at a rate of 6.25% per annum on the liquidation preference of $1,000 per share and can be paid in cash, common stock or a combination of both. 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 our common stock (and, correspondingly, each depositary share will convert into between 1.85014 and 2.17391 shares of our common stock), subject to customary anti-dilution adjustments, depending on the volume-weighted average price of our common stock over a 20 trading-day period immediately prior to that date.

Our 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. As such, 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.

In January 2015, we completed a public offering of $350 million aggregate principal amount of our 3.30% senior notes due 2018 (the “2018 Notes”), $850 million aggregate principal amount of our 4.05% senior notes due 2020 (the “2020 Notes”) and $1.0 billion aggregate principal amount of our 4.95% senior notes due 2025 (the “2025 Notes” and 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 proceeds from the sale of the Notes were used to repay all principal and interest remaining outstanding under our $4.5 billion 364-day bridge facility, which was first reduced with proceeds from our concurrent underwritten public offerings of common stock and depositary shares. Proceeds from the sale of the Notes were also used to repay a portion of amounts outstanding under our existing revolving credit facility. The Notes were sold to the public at a price of 99.949% of their face value for the 2018 Notes, 99.897% of their face value for the 2020 Notes and 99.782% of their face value for the 2025 Notes. The interest rates on the Notes are determined based on our public bond ratings from Moody’s and S&P. Downgrades on the Notes from either rating agency increase our interest costs by 25.0 basis points per downgrade level on the following semi-annual bond interest payment. Based on the February and June 2016 downgrades from Moody’s and S&P, our interest rates on these Notes will increase by 175.0 basis points effective July 2016. On July 20, 2016, we used a portion of the proceeds from the July 2016 equity offering to settle certain tender offers by purchasing an aggregate principal amount of approximately $700 million of our outstanding senior notes due in the first quarter of 2018.

Our derivative contracts allow us to ensure a certain level of cash flow to fund our operations. Excluding basis swaps, at July 19, 2016, we had commodity price derivatives in place on 93 Bcf of our remaining targeted 2016 natural gas production and 228 Bcf on our targeted 2017 natural gas production. The amount of long-term debt we incur will be largely dependent upon commodity prices and our capital investment plans.

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 June 30, 2016, our material off-balance sheet arrangements and transactions include operating lease arrangements. 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 2015 Annual Report.

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 agreements discussed below, there have been no material changes to our contractual obligations from those disclosed in our 2015 Annual Report.

Contingent Liabilities and Commitments

As of June 30, 2016, our 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 $8.6 billion, $3.3 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 $861 million. As of June 30, 2016, future payments under non-cancelable firm transportation and gathering agreements are as follows:

	Payments Due by Period					
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	5 to 8 Years	More than 8 Years
	(in millions)					
Infrastructure Currently in Service	**$ 5,243**	$ 561	$ 1,136	$ 883	$ 852	$ 1,811
Pending Regulatory Approval and/or Construction (1)	**3,338**	13	231	452	672	1,970
Total Transportation Charges	**$ 8,581**	$ 574	$ 1,367	$ 1,335	$ 1,524	$ 3,781

(1) Based on the estimated in-service dates as of June 30, 2016.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. For the six months ended June 30, 2016, we have contributed $6 million to the pension and postretirement benefit plans. We expect to contribute an additional $5 million to our pension and postretirement benefit plans during the remainder of 2016. As of June 30, 2016 and December 31, 2015, we recognized a liability of $52 million and $51 million, respectively, as a result of the underfunded status of our pension and other postretirement benefit plans. See Note 12 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 litigation, claims and proceedings that arise in the ordinary course of business, such as for alleged breaches of contract, miscalculation of royalties and pollution, contamination or nuisance. Management believes that such 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. 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. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position, results of operations or cash flows for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated. For further information, we refer you to "Legal Proceedings" in Item 1 of Part II 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.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our cash and cash equivalents and our revolving credit facility described in "Financing Requirements" above. We had positive working capital of $687 million at June 30, 2016 and negative working capital of $314 million at December 31, 2015. The positive working capital as of June 30, 2016 was primarily due to $998 million of cash and cash equivalents resulting from our new term loan. The negative working capital as of December 31, 2015 was primarily due to a decrease in derivative assets in 2015.

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 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 risks is subject to the approval of 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 purchasers and their dispersion across geographic areas. No single purchaser accounted for greater than 10% of revenues for the six months ended June 30, 2016. See "Commodities Risk" below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At June 30, 2016, we had approximately $3.9 billion of outstanding senior notes with a weighted average interest rate of 4.817%, $1,191 million of term loan facility debt with a variable interest rate of 2.94% and $750 million of term loan facility debt with a variable interest rate of 2.93%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

	Expected Maturity Date						
	2016	2017	2018	2019	2020	Thereafter	Total
Fixed Rate Payments [1]	$ 1	$ 41	$ 975	$ –	$ 850	$ 2,000	$ 3,866
Weighted Average Interest Rate	7.15 %	7.21 %	5.98 %	– %	4.05 %	4.53 %	4.82 %
Variable Rate Payments [1]	–	–	750	–	–	–	1,941
Weighted Average Interest Rate	– %	– %	2.93 %	– %	– %	– %	2.94 %

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

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 7 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.

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 June 30, 2016 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 June 30, 2016 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 11 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.

Other than the following additional risk factor, there were no additions or material changes to our risk factors as disclosed in Item 1A of Part I in the Company's 2015 Annual Report.

Certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and production may be eliminated as a result of future legislation.

The elimination of certain key U.S. federal income tax deductions currently available to oil and natural gas exploration and production companies has been proposed in recent years by members of the U.S. Congress and by the President in his fiscal year 2017 budget proposal. These changes have included, among other proposals:

- repeal of the percentage depletion allowance for natural gas and oil properties;
- elimination of current deductions for intangible drilling and development costs;
- elimination of the deduction for certain domestic production activities; and
- extension of the amortization period for certain geological and geophysical expenditures.

In addition, the President's fiscal year 2017 budget proposal includes the imposition of a new $10.25 per barrel fee on certain oil production, to be paid by certain oil companies (without precise details regarding the implementation of such fee). It is unclear whether these or similar changes will be enacted. The passage of these or any similar changes in U.S. federal income tax laws to eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development could have an adverse effect on our financial position, results of operations and cash flows.

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.

ITEM 6. EXHIBITS.

(10.1)	First Amendment to Southwestern Energy Company 2013 Incentive Plan. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 20, 2016)
(10.2)*	Retirement Agreement dated May 19, 2016 between Southwestern Energy Company and Jeffrey B. Sherrick
(10.3)*	Amendment to Awards Agreement dated May 19, 2016 between Southwestern Energy Company and Jeffrey B. Sherrick
(10.4)	Amended and Restated Term Loan Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit A to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
(10.5)	Credit Agreement, dated June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders from time to time party thereto. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
(10.6)	Amendment and Restatement Agreement, dated June 27, 2016 among Southwestern Energy Company, Bank of America, N.A., as Administrative Agent, and the lenders party thereto, giving effect to the Amended and Restated Term Loan Credit Agreement. (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
(10.7)	Amendment No. 1 to Credit Agreement, dated as of June 27, 2016 among Southwestern Energy Company, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto. (Incorporated by reference to Exhibit A to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on June 27, 2016)
(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: July 21, 2016

/s/ R. CRAIG OWEN
R. Craig Owen
Senior Vice President
and Chief Financial Officer