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 **September 30, 2015**

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: **1-08246**

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 October 20, 2015
Common Stock, Par Value $0.01	384,478,569

SOUTHWESTERN ENERGY COMPANY

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FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2015

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," "project," "intend," "estimate," "expect," "believe," "predict," "budget," "projection," "goal," "plan," "forecast," "target" or similar expressions.

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 and oil (including regional basis differentials);
- our ability to fund our planned capital investments;
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- the economic viability of, and our success in drilling, our large positions in the Fayetteville Shale, Northeast Appalachia and Southwest Appalachia overall as well as relative to other productive shale gas plays;
- our ability to realize the expected benefits from recent acquisitions;

- the impact of title and environmental defects and other matters on the value of the properties acquired in our recent acquisitions and any other future acquisitions;
- difficulties in integrating our operations as a result of any significant acquisitions;
- 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 costs and availability of oilfield personnel, services and drilling supplies, raw materials and equipment, including pressure pumping equipment and crews;
- our ability to determine the most effective and economic fracture stimulation;
- our future property acquisition or divestiture activities;
- 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;
- the different risks and uncertainties associated with proposed activities in Canada;
- conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;
- 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 September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions, except share/per share amounts)			
Operating Revenues:				
Gas sales	$ **458**	$ 645	**$ 1,540**	$ 2,155
Oil sales	**19**	6	**60**	12
NGL sales	**14**	–	**47**	1
Marketing	**216**	227	**663**	765
Gas gathering	**42**	50	**136**	143
	749	928	**2,446**	3,076
Operating Costs and Expenses:				
Marketing purchases	**213**	220	**654**	752
Operating expenses	**176**	108	**507**	309
General and administrative expenses	**60**	54	**188**	162
Depreciation, depletion and amortization	**275**	238	**876**	693
Impairment of natural gas and oil properties	**2,839**	–	**4,374**	–
(Gain) loss on sale of assets, net	**1**	–	**(276)**	–
Taxes, other than income taxes	**27**	22	**84**	72
	3,591	642	**6,407**	1,988
Operating Income (Loss)	**(2,842)**	286	**(3,961)**	1,088
Interest Expense:				
Interest on debt	**51**	25	**153**	75
Other interest charges	**2**	2	**54**	4
Interest capitalized	**(53)**	(14)	**(155)**	(40)
	–	13	**52**	39
Other Income, Net	**–**	–	**2**	1
Gain (Loss) on Derivatives	**15**	78	**30**	(29)
Income (Loss) Before Income Taxes	**(2,827)**	351	**(3,981)**	1,021
Provision (Benefit) for Income Taxes:				
Current	**–**	32	**7**	34
Deferred	**(1,088)**	108	**(1,539)**	375
	(1,088)	140	**(1,532)**	409
Net Income (Loss)	$ **(1,739)**	$ 211	**$ (2,449)**	$ 612
Mandatory convertible preferred stock dividend	**27**	–	**79**	–
Net Income (Loss) Attributable to Common Stock	**$ (1,766)**	$ 211	**$ (2,528)**	$ 612
Earnings (Loss) Per Common Share:				
Basic	$ **(4.62)**	$ 0.60	**$ (6.65)**	$ 1.74
Diluted	$ **(4.62)**	$ 0.60	**$ (6.65)**	$ 1.74
Weighted Average Common Shares Outstanding:				
Basic	**382,098,080**	351,457,043	**379,909,748**	351,357,913
Diluted	**382,098,080**	352,327,250	**379,909,748**	352,334,546

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 September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions)			
Net income (loss)	**$ (1,739)**	$ 211	**$ (2,449)**	$ 612
Change in derivatives:				
Settlements [1]	**(31)**	(11)	**(89)**	29
Ineffectiveness [2]	**1**	(2)	**1**	(1)
Change in fair value of derivative instruments [3]	**8**	48	**21**	(1)
Total change in derivatives	**(22)**	35	**(67)**	27
Change in value of pension and other postretirement liabilities:				
Amortization of prior service cost and net loss included in net periodic pension cost [4]	**1**	–	**1**	–
Change in currency translation adjustment	**(5)**	(4)	**(9)**	(4)
Comprehensive income (loss)	**$ (1,765)**	$ 242	**$ (2,524)**	$ 635

(1) Net of ($19), ($7), ($56) and $19 million in taxes for the three months ended September 30, 2015 and 2014, and nine months ended September 30, 2015 and 2014, respectively.

(2) Net of ($1) million in taxes for the three months ended September 30, 2014.

(3) Net of $5, $32, $13 and ($1) million in taxes for the three months ended September 30, 2015 and 2014, and nine months ended September 30, 2015 and 2014, respectively.

(4) Net of $1 million in taxes for the nine months ended September 30, 2015.

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

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

	September 30, 2015	December 31, 2014
ASSETS	(in millions)	
Current assets:		
Cash and cash equivalents	$ **15**	$ 53
Accounts receivable	**355**	530
Inventories	**33**	37
Derivative assets	**112**	337
Other current assets	**55**	158
Total current assets	**570**	1,115
Natural gas and oil properties, using the full cost method, including $4,902 million as of September 30, 2015 and $4,646 million as of December 31, 2014 excluded from amortization	**22,127**	20,506
Gathering systems	**1,274**	1,439
Other	**616**	612
Less: Accumulated depreciation, depletion and amortization	**(14,038)**	(8,845)
Total property and equipment, net	**9,979**	13,712
Other long-term assets	**176**	98
TOTAL ASSETS	$ **10,725**	$ 14,925
LIABILITIES AND EQUITY		
Current liabilities:		
Short-term debt	$ **1**	$ 4,501
Accounts payable	**615**	653
Taxes payable	**49**	92
Interest payable	**32**	34
Current deferred income taxes	**24**	109
Dividends payable	**27**	–
Derivative liabilities	**6**	9
Other current liabilities	**28**	30
Total current liabilities	**782**	5,428
Long-term debt	**4,663**	2,466
Deferred income taxes	**448**	1,951
Pension and other postretirement liabilities	**48**	44
Other long-term liabilities	**347**	374
Total long-term liabilities	**5,506**	4,835
Commitments and contingencies (Note 10)		
Equity:		
Common stock, $0.01 par value; authorized 1,250,000,000 shares; issued 384,552,961 shares as of September 30, 2015 and 354,488,992 as of December 31, 2014	**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	**–**	–
Additional paid-in capital	**3,396**	1,019
Retained earnings	**1,051**	3,577
Accumulated other comprehensive income (loss)	**(13)**	62
Common stock in treasury, 45,990 shares as of September 30, 2015 and 11,055 shares as of December 31, 2014	**(1)**	–
Total equity	**4,437**	4,662
TOTAL LIABILITIES AND EQUITY	$ **10,725**	$ 14,925

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

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

	For the nine months ended September 30, 2015	2014
	(in millions)	
Cash Flows From Operating Activities		
Net income (loss)	**$ (2,449)**	$ 612
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	**877**	693
Impairment of natural gas and oil properties	**4,374**	–
Amortization of debt issuance cost	**50**	3
Deferred income taxes	**(1,539)**	375
Loss on derivatives excluding derivatives, settled	**105**	7
Stock-based compensation	**18**	13
Gain on sale of assets, net	**(276)**	–
Other	**2**	(3)
Change in assets and liabilities:		
Accounts receivable	**175**	7
Inventories	**2**	2
Accounts payable	**(55)**	52
Taxes payable (receivable)	**(43)**	1
Interest payable	**(1)**	(10)
Other assets and liabilities	**(13)**	22
Net cash provided by operating activities	**1,227**	1,774
Cash Flows From Investing Activities		
Capital investments	**(1,392)**	(1,511)
Acquisitions	**(582)**	(202)
Proceeds from sale of property and equipment	**704**	20
Other	**7**	6
Net cash used in investing activities	**(1,263)**	(1,687)
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	**(2,168)**	(3,573)
Borrowings under revolving credit facility	**2,148**	3,429
Payments on commercial paper	**(5,179)**	–
Borrowings under commercial paper	**5,699**	–
Change in bank drafts outstanding	**26**	45
Proceeds from issuance of long-term debt	**2,200**	–
Debt issuance costs	**(17)**	–
Proceeds from exercise of common stock options	**–**	10
Proceeds from issuance of common stock	**669**	–
Proceeds from issuance of mandatory convertible preferred stock	**1,673**	–
Mandatory convertible preferred stock dividend	**(52)**	–
Net cash used in financing activities	**(2)**	(90)
Decrease in cash and cash equivalents	**(38)**	(3)
Cash and cash equivalents at beginning of year	**53**	23
Cash and cash equivalents at end of period	**$ 15**	$ 20

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 Issued	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Total
			(in millions, except share amounts)					
Balance at December 31, 2014	354,488,992	$ 4	–	$ 1,019	$ 3,577	$ 62	$ –	$ 4,662
Comprehensive loss:								
Net loss	–	–	–	–	(2,449)	–	–	(2,449)
Other comprehensive loss	–	–	–	–	–	(75)	–	(75)
Total comprehensive loss	–	–	–	–	–	–	–	(2,524)
Stock-based compensation	–	–	–	35	–	–	–	35
Preferred stock dividends	–	–	–	–	(79)	–	–	(79)
Issuance of restricted stock	105,584	–	–	–	–	–	–	–
Cancellation of restricted stock	(69,657)	–	–	–	–	–	–	–
Issuance of common stock	30,000,000	–	–	669	–	–	–	669
Issuance of preferred stock	–	–	1,725,000	1,673	–	–	–	1,673
Treasury stock – non-qualified plan	–	–	–	–	–	–	(1)	(1)
Tax withholding – stock compensation	(1,958)	–	–	–	–	–	–	–
Non-controlling interest	–	–	–	–	2	–	–	2
Balance at September 30, 2015	**384,522,961**	**$ 4**	**1,725,000**	**$ 3,396**	**$ 1,051**	**$ (13)**	**$ (1)**	**$ 4,437**

The accompanying notes are an integral part of these
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's current operations are principally focused within the United States on the development of unconventional reservoirs located in Arkansas, Pennsylvania and West Virginia. The Company's operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, and its operations in northeast Pennsylvania are focused on an unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as "Northeast Appalachia"). The Company also has a significant stake in properties located in West Virginia and adjacent areas in southwest Pennsylvania. These operations, primarily in West Virginia, are focused on the Marcellus, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as "Southwest Appalachia"). To a lesser extent, the Company has exploration and production activities ongoing in Colorado, Louisiana and elsewhere in the United States. The Company also actively seeks to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which it refers to as "New Ventures," and to obtain additional reserves through acquisitions. The Company also operates drilling rigs in Arkansas, Pennsylvania and West Virginia, and provides oilfield products and services, principally serving its exploration and production operations. Southwestern's natural gas gathering and marketing ("Midstream Services") activities primarily support the Company's E&P activities in Arkansas, Pennsylvania, Louisiana and West Virginia.

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, 2014 ("2014 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 2014 Annual Report.

(2) ACQUISITIONS AND DIVESTITURES

In May 2015, the Company sold conventional oil and gas assets located in East Texas and the Arkoma Basin for approximately $214 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 Company debt. Approximately $206 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. The transaction is subject to customary post-closing adjustments.

In April 2015, the Company sold its gathering assets located in Bradford and Lycoming counties in northeastern 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) loss on sale of assets, net on the unaudited condensed consolidated statement of operations. The assets include 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. This transaction was funded with the revolving credit facility and was accounted for as a business combination. The Company allocated approximately $151 million of the purchase price of the WPX Property Acquisition to natural gas and oil properties and approximately $119 million to intangible assets in other current assets and other long-term assets, based on the respective fair values of the assets acquired which have been updated to reflect final settlement adjustments.

In January 2015, the Company completed an acquisition in which the Company's subsidiary acquired 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 $365 million, subject to customary post-closing adjustments (the "Statoil Property Acquisition"). All of these assets are also assets in which the Company has 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 approximately $365 million of 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 natural gas and oil assets from Chesapeake Energy Corporation covering approximately 413,000 net acres in West Virginia and southwest Pennsylvania targeting natural gas, natural gas liquids ("NGLs") and crude oil contained in the Upper Devonian, Marcellus and Utica Shales for approximately $5.0 billion, subject to customary post-closing adjustments (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.

The Chesapeake Property Acquisition qualified as a business combination, and as a result, the Company estimated the fair value of the assets acquired and liabilities assumed as of the December 22, 2014 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as defined in Note 8 – Fair Value Measurements. The following table summarizes the consideration paid for the Chesapeake Property Acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date. The purchase price allocation is preliminary and has been adjusted to reflect changes in unproved property and working capital. These amounts are subject to further adjustments and will be finalized as soon as possible, but no later than December 2015.

Consideration (in millions):		
Cash	$	4,959
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired:		
Proved natural gas and oil properties		1,418
Unproved natural gas and oil properties		3,574
Other property and equipment		33
Inventory		3
Total assets acquired		5,028
Liabilities assumed:		
Asset retirement obligations		(42)
Other liabilities		(27)
Total liabilities assumed		(69)
	$	4,959

Summarized below are the consolidated results of operations for the three and nine months ended September 30, 2014 on an unaudited pro forma basis, as if the acquisition and financing had occurred on January 1, 2013. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the Chesapeake Property Acquisition properties. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related permanent financing occurred on the basis assumed above, nor is such information indicative of the Company's expected future results of operations. The unaudited pro forma financial information excludes the WPX Property and Statoil Property Acquisitions as the impacts are immaterial.

	For the three months ended September 30, 2014	For the nine months ended September 30, 2014
	(unaudited) (in millions, except per share amounts)	
Revenues	$ 1,019	$ 3,416
Net Income	$ 234	$ 720
Earnings per common share:		
Basic	$ 0.46	$ 1.43
Diluted	$ 0.45	$ 1.42

In the second and third quarters of 2014, the Company completed several acquisitions to purchase approximately 380,000 net acres in northwest Colorado principally in the Niobrara formation for approximately $215 million. The Company utilized its revolving credit facility to finance these acquisitions and accounted for them as asset acquisitions.

(3) INVENTORY

Inventory is comprised of tubulars and other equipment and natural gas in underground storage. Tubulars and other equipment are carried at the lower of cost or market and are accounted for by a moving weighted average cost method that is applied within specific classes of inventory items. Natural gas in underground storage is carried at the lower of cost or market and accounted for by a weighted average cost method.

The components of inventory recorded in current assets as of September 30, 2015 and December 31, 2014 consisted of the following:

	September 30, 2015	December 31, 2014
	(in millions)	
Tubulars and other equipment	$ **31**	$ 33
Natural gas in underground storage	$ **2**	$ 4

(4) NATURAL GAS AND OIL PROPERTIES

The Company utilizes the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil reserves. 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, less accumulated amortization and related deferred income taxes, are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10% 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 and oil prices may subsequently increase the ceiling. Companies using the full cost method must use the average quoted price from the first day of each month from the previous 12 months, including the impact of derivatives qualifying as cash flow hedges, to calculate the ceiling value of their reserves.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $3.06 per MMBtu, West Texas Intermediate oil of $55.73 per barrel and NGLs of $8.62 per barrel, adjusted for market differentials, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by $1,746 million (net of tax) at September 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 $40 million as of September 30, 2015. In the second quarter of 2015, the Company's net book value of its United States natural gas and oil properties exceeded the ceiling by approximately $944 million (net of tax) at June 30, 2015 and resulted in a non-cash ceiling test impairment. 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 first-day-of-the-month prices of natural gas for the first ten months of 2015 and NYMEX strip prices for the remainder of 2015, as applicable, the prices required to be used to determine the ceiling amount in the Company's full cost ceiling test are likely to require a material write-down in the fourth quarter of 2015. The Company assesses the available positive and negative evidence to estimate if sufficient future taxable income will be generated to utilize its deferred tax assets. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. While the Company is unable to reasonably estimate the amounts at this time, based on the expected material write-downs of the value of its oil and natural gas properties, it is possible the Company's deferred tax assets will not be realized in subsequent quarters.

Using the average quoted price from the first day of each month from the previous 12 months for Henry Hub natural gas of $4.24 per MMBtu, West Texas Intermediate oil of $95.56 per barrel and NGLs of $36.70 per barrel, adjusted for market differentials, the net book value of the Company's United States natural gas and oil properties did not exceed the ceiling amount and did not result in a ceiling test impairment at September 30, 2014. Cash flow hedges of natural gas production in place increased the ceiling amount by approximately $14 million as of September 30, 2014.

All of the Company's costs directly associated with the acquisition and evaluation of properties in Canada relating to its exploration program as of September 30, 2015 were unproved and did not exceed the ceiling amount. If the Company's exploration program in Canada is terminated or otherwise unsuccessful on all or a portion of the Company's Canadian assets, including the effects of the recently imposed moratorium in New Brunswick and changes in laws or regulations or otherwise, a ceiling test impairment may result in the future.

(5) EARNINGS PER SHARE

Basic earnings per common share is computed by dividing net income (loss) attributable to common stock by the weighted average number of common shares outstanding during each year. 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 and the assumed conversion of mandatory convertible preferred stock. An antidilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

In 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 holders 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 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.

The following table presents the computation of earnings per share for the three and nine months ended September 30, 2015 and 2014:

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions, except share/per share amounts)			
Net income (loss)	**$ (1,739)**	$ 211	**$ (2,449)**	$ 612
Mandatory convertible preferred stock dividend	**27**	–	**79**	–
Net income (loss) attributable to common stock	**(1,766)**	211	**(2,528)**	612
Number of common shares:				
Weighted average outstanding	**382,098,080**	351,457,043	**379,909,748**	351,357,913
Issued upon assumed exercise of outstanding stock options [(1)]	**–**	235,944	**–**	354,940
Effect of issuance of non-vested restricted common stock [(2)]	**–**	514,668	**–**	484,786
Effect of issuance of non-vested performance units [(3)]	**–**	119,595	**–**	136,907
Effect of issuance of mandatory convertible preferred stock [(4)]	**–**	–	**–**	–
Weighted average and potential dilutive outstanding	**382,098,080**	352,327,250	**379,909,748**	352,334,546
Earnings (loss) per common share:				
Basic	**$ (4.62)**	$ 0.60	**$ (6.65)**	$ 1.74
Diluted	**$ (4.62)**	$ 0.60	**$ (6.65)**	$ 1.74

(1) Due to the net loss for the three and nine months ended September 30, 2015, options of 3,796,778 shares and 3,778,140 shares, respectively, were antidilutive and excluded from the calculation of diluted earnings per share. For the three and nine months ended September 30, 2014, options of 1,254,842 shares and 1,111,128 shares, respectively, were antidilutive and excluded from the calculation of diluted earnings per share.

(2) Due to the net loss for the three and nine months ended September 30, 2015, 1,469,380 shares and 1,472,379 shares, respectively, of restricted stock were antidilutive and excluded from the calculation of diluted earnings per share. For the three and nine months ended September 30, 2014, 27,916 shares and 24,215 shares, respectively, of restricted stock were antidilutive and excluded from the calculation of diluted earnings per share.

(3) Due to the net loss for the three and nine months ended September 30, 2015, 89,802 shares and 135,836 shares, respectively, of performance units were antidilutive and excluded from the calculation of diluted earnings per share.

(4) Due to the net loss for the three and nine months ended September 30, 2015, 74,999,895 and 69,505,397 of weighted average common shares issuable upon the assumed conversion of the mandatory convertible preferred stock, respectively, were antidilutive and excluded from the calculation of diluted earnings per share.

(6) DERIVATIVES AND RISK MANAGEMENT

The Company is exposed to volatility in market prices and basis differentials for natural gas and oil which impacts the predictability of its cash flows related to the sale of natural gas, NGLs and oil. These risks are managed by the Company's use of certain derivative financial instruments. As of September 30, 2015 and December 31, 2014, the Company's derivative financial instruments consisted of fixed price swaps, floating price swaps, basis swaps, fixed price call options, and interest rate swaps. A description of the Company's derivative financial instruments is provided below:

Fixed price swaps	The Company receives a fixed price for the contract and pays a floating market price to the counterparty.
Floating price swaps	The Company receives a floating market price from the counterparty and pays a fixed 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.
Fixed price call options	The Company sells fixed price call options in exchange for a premium. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the counterparty such excess on sold fixed price call options. If the market price settles below the fixed price of the call option, 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.

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 classified and accounted for as either a cash flow or a fair value hedge. Accounting for qualifying hedges requires a derivative's gains and losses to be recorded either in earnings or as a component of other comprehensive income. In the period of settlement, the Company recognizes the gains and losses from these qualifying hedges in operating revenues. Gains and losses on derivatives that are not designated for hedge accounting treatment or that do not meet hedge accounting requirements are recorded in earnings as a component of gain (loss) on derivatives. Within the gain (loss) on derivatives component of the statement of operations are gains (losses) on derivatives excluding derivatives, settled and gains (losses) on derivatives, settled. The Company calculates gains (losses) on derivatives, settled, as the summation of gains and losses on positions which have settled within the period.

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 balance sheet classification of the assets related to derivative financial instruments are summarized below as of September 30, 2015 and December 31, 2014:

	Derivative Assets			
	September 30, 2015		December 31, 2014	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in millions)			
Derivatives designated as hedging instruments:				
Fixed price swaps	Derivative assets	$ **55**	Derivative assets	$ 165
Total derivatives designated as hedging instruments		$ **55**		$ 165
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative assets	$ **3**	Derivative assets	$ 9
Fixed price swaps	Derivative assets	**54**	Derivative assets	163
Basis swaps	Other long-term assets	**–**	Other long-term assets	1
Interest rate swaps	Other long-term assets	**–**	Other long-term assets	1
Total derivatives not designated as hedging instruments		$ **57**		$ 174
Total derivative assets		$ **112**		$ 339

	Derivative Liabilities			
	September 30, 2015		December 31, 2014	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
	(in millions)			
Derivatives not designated as hedging instruments:				
Basis swaps	Derivative liabilities	$ **3**	Derivative liabilities	$ 4
Fixed price call options	Derivative liabilities	**–**	Derivative liabilities	2
Interest rate swaps	Derivative liabilities	**3**	Derivative liabilities	3
Basis swaps	Other long-term liabilities	**–**	Other long-term liabilities	2
Fixed price call options	Other long-term liabilities	**1**	Other long-term liabilities	10
Interest rate swaps	Other long-term liabilities	**4**	Other long-term liabilities	2
Total derivatives not designated as hedging instruments		$ **11**		$ 23
Total derivative liabilities		$ **11**		$ 23

As of September 30, 2015, the Company had fixed price swap derivatives designated for hedge accounting and not designated for hedge accounting on the following volumes of natural gas production (in Bcf):

Year	Fixed price swaps designated for hedge accounting	Fixed price swaps not designated for hedge accounting	Total	Weighted Average Swap Price ($/MMBtu) [(1)]
2015	30	30	60	$4.40

(1) The weighted average swap price is $4.40 for each category and in total.

Cash Flow Hedges

The Company has certain fixed price swaps that are designated for hedge accounting. The reporting of gains and losses on cash flow derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gains and losses on the derivative hedging instruments are recorded in other comprehensive income until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from the derivative hedging instrument are recognized in earnings immediately and had an inconsequential impact to the unaudited condensed consolidated statement of operations for the three and nine months ended September 30, 2015 and 2014.

As of September 30, 2015, accumulated other comprehensive income includes a gain related to its hedging activities of $31 million net of a deferred income tax liability of $23 million. The amount included in accumulated other comprehensive income will be relieved over time and recognized in the statement of operations as the physical transactions being hedged occur. Assuming the market prices of natural gas futures as of September 30, 2015 remain unchanged, the Company would expect to transfer an aggregate after-tax net gain of approximately $31 million from accumulated other comprehensive income to earnings during the next 12 months. Gains or losses from derivative instruments designated as cash flow hedges are reflected as adjustments to natural gas sales in the consolidated statements of operations. Volatility in net income, comprehensive income and accumulated other comprehensive income may occur in the future as a result of the Company's derivative activities.

The following tables summarize the before tax effect of all fixed price swaps designated for hedge accounting on the unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2015 and 2014:

	Gain (Loss) Recognized in Other Comprehensive Loss (Effective Portion)			
	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument	**2015**	2014	**2015**	2014
	(in millions)			
Fixed price swaps	**$ 14**	$ 80	**$ 35**	$ (2)

	Classification of Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)	Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Earnings (Effective Portion)			
		For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		**2015**	2014	**2015**	2014
		(in millions)			
Fixed price swaps	Gas sales	**$ 50**	$ 18	**$ 145**	$ (48)

Other Derivative Contracts

For other derivative contracts, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item are recognized in earnings immediately through gain (loss) on derivatives. Although the Company's basis swaps meet the objective of managing commodity price exposure, these trades are typically not entered into concurrent with the Company's derivative instruments that qualify as cash flow hedges and therefore do not generally qualify for hedge accounting. Basis swap derivative instruments that are not designated for hedge accounting are recorded on the balance sheet at their fair values under derivative assets, other long-term assets, other current liabilities, and other long-term liabilities, as applicable and all gains and losses related to these contracts are recognized immediately in the unaudited condensed consolidated statement of operations as a component of gain (loss) on derivatives. As of September 30, 2015, the Company had basis swaps on natural gas production that were not designated for hedge accounting of 4 Bcf and 4 Bcf in 2015 and 2016, respectively.

As of September 30, 2015, the Company had fixed price call options on 50 Bcf and 120 Bcf of natural gas production in 2015 and 2016, respectively, not designated for hedge accounting and fixed price swaps of 30 Bcf of natural gas production in 2015 not designated for hedge accounting.

As of September 30, 2015 the Company had a floating price swap on less than 1 Bcf of natural gas production in 2015 not designated for hedge accounting which had an inconsequential impact on the unaudited consolidated financial statements.

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, basis swaps, fixed price call options and interest rate swaps not designated for hedge accounting on the unaudited condensed consolidated statements of operations for the three and nine months ended September 30, 2015 and 2014:

		Gain (Loss) on Derivatives Excluding Derivatives, Settled Recognized in Earnings			
	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Net of Settlement	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		**2015**	2014	**2015**	2014
		(in millions)			
Basis swaps	Gain (Loss) on Derivatives	$ **1**	$ (3)	$ **(4)**	$ (16)
Fixed price call options	Gain (Loss) on Derivatives	$ **3**	$ 11	$ **11**	$ (11)
Fixed price swaps	Gain (Loss) on Derivatives	$ **(37)**	$ 45	$ **(110)**	$ 24
Interest rate swaps	Gain (Loss) on Derivatives	$ **(1)**	$ 1	$ **(2)**	$ (4)

		Gain (Loss) on Derivatives, Settled (1) Recognized in Earnings			
	Consolidated Statement of Operations Classification of Gain (Loss) on Derivatives, Settled (1)	For the three months ended September 30,		For the nine months ended September 30,	
Derivative Instrument		**2015**	2014	**2015**	2014
		(in millions)			
Basis swaps	Gain (Loss) on Derivatives	$ **–**	$ 9	$ **(6)**	$ –
Fixed price swaps	Gain (Loss) on Derivatives	$ **49**	$ 15	$ **143**	$ (21)
Interest rate swaps	Gain (Loss) on Derivatives	$ **–**	$ –	$ **(2)**	$ (1)

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

(7) RECLASSIFICATIONS FROM ACCUMULATED OTHER COMPREHENSIVE INCOME

The following tables detail the components of accumulated other comprehensive income and the related tax effects for the nine months ended September 30, 2015:

	For the nine months ended September 30, 2015 (in millions) [1]			
	Cash Flow Hedges	Pension and Other Postretirement	Foreign Currency	Total
Beginning balance at December 31, 2014	$ 98	$ (24)	$ (12)	$ 62
Other comprehensive income (loss) before reclassifications	21	–	(9)	12
Amounts reclassified from/to other comprehensive income (loss) [2]	(88)	1	–	(87)
Net current period other comprehensive income (loss)	(67)	1	(9)	(75)
Ending balance at September 30, 2015	**$ 31**	**$ (23)**	**$ (21)**	**$ (13)**

(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/to Accumulated Other Comprehensive Income For the nine months ended September 30, 2015 (in millions)
Cash flow hedges		
Settlements	Gas sales	$ (145)
Ineffectiveness	Gain (Loss) on Derivatives	1
	Provision (Benefit) for Income Taxes	(56)
	Net Income (Loss)	$ (88)
Pension and other postretirement		
Amortization of prior service cost and net loss [1]	General and administrative expenses	$ 2
	Provision (Benefit) for Income Taxes	1
	Net Income (Loss)	$ 1
Total reclassifications for the period	Net Income (Loss)	$ (87)

(1) See Note 11 for additional details regarding the Company’s retirement and employee benefit plans.

(8) FAIR VALUE MEASUREMENTS

The carrying amounts and estimated fair values of the Company's financial instruments as of September 30, 2015 and December 31, 2014 were as follows:

	September 30, 2015				December 31, 2014			
	Carrying Amount		Fair Value		Carrying Amount		Fair Value	
	(in millions)							
Cash and cash equivalents	$	**15**	$	**15**	$	53	$	53
Credit facility	$	**280**	$	**280**	$	300	$	300
Commercial paper	$	**520**	$	**520**	$	–	$	–
Term loan facility (1)	$	**–**	$	**–**	$	500	$	500
Bridge facility (2)	$	**–**	$	**–**	$	4,500	$	4,500
Senior notes	$	**3,864**	$	**3,716**	$	1,667	$	1,751
Derivative instruments, net	$	**101**	$	**101**	$	316	$	316

(1) 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.

(2) The bridge facility was repaid in full in January 2015 with proceeds from the issuance of $2.2 billion of long-term senior notes and the $2.3 billion issuance of common and preferred stock.

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 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 facility, commercial paper program and previously, bridge 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 September 30, 2015 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 fixed price call options (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. However, such changes would not have a significant impact.

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

	September 30, 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**
Fixed price swap assets	$ **–**	$ **109**	$ **–**	$ **109**
Interest rate swap assets	**–**	**–**	**–**	**–**
Basis swap assets	**–**	**–**	**3**	**3**
Interest rate swap liabilities	**–**	**(7)**	**–**	**(7)**
Basis swap liabilities	**–**	**–**	**(3)**	**(3)**
Fixed price call option liabilities	**–**	**–**	**(1)**	**(1)**
Total	$ **–**	$ **102**	$ **(1)**	$ **101**

	December 31, 2014			
	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	$ –	$ 328	$ –	$ 328
Interest rate swap assets	–	1	–	1
Basis swap assets	–	–	10	10
Interest rate swap liabilities	–	(5)	–	(5)
Basis swap liabilities	–	–	(6)	(6)
Fixed price call option liabilities	–	–	(12)	(12)
Total	$ –	$ 324	$ (8)	$ 316

The table below presents reconciliations for the change in net fair value of derivative assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) for the three and nine months ended September 30, 2015 and 2014. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in the Company's judgment, reflect reasonable assumptions a marketplace participant would have used as of September 30, 2015 and September 30, 2014.

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions)			
Balance at beginning of period	$ **(5)**	$ (55)	$ **(8)**	$ (19)
Total gains (losses):				
Included in earnings	**4**	18	**1**	(27)
Included in other comprehensive loss	**–**	–	**–**	–
Purchases, issuances, and settlements:				
Purchases	**–**	–	**–**	–
Issuances	**–**	–	**–**	–
Settlements	**–**	(9)	**6**	–
Transfers into/out of Level 3	**–**	–	**–**	–
Balance at end of period	$ **(1)**	$ (46)	$ **(1)**	$ (46)
Change in gains (losses) included in earnings relating to derivatives still held as of September 30	$ **4**	$ 9	$ **7**	$ (27)

(9) DEBT

The components of debt as of September 30, 2015 and December 31, 2014 consisted of the following:

	September 30, 2015	December 31, 2014
	(in millions)	
Short-term debt:		
7.15% Senior Notes due 2018	$ **1**	$ 1
Variable rate (1.515% at December 31, 2014) bridge facility, due December 2015 [(1)]	**–**	4,500
Total short-term debt	$ **1**	$ 4,501
Long-term debt:		
Commercial paper (1.266% at September 30, 2015)	$ **520**	$ –
Variable rate (1.664% and 1.515% at September 30, 2015 and December 31, 2014, respectively) unsecured revolving credit facility	**280**	300
Variable rate (1.545% at December 31, 2014) term loan facility, due December 2016 [(2)]	**–**	500
7.35% Senior Notes due 2017	**15**	15
7.125% Senior Notes due 2017	**25**	25
7.15% Senior Notes due 2018	**27**	27
3.3% Senior Notes due 2018	**350**	–
7.5% Senior Notes due 2018	**600**	600
4.05% Senior Notes due 2020	**850**	–
4.10% Senior Notes due 2022	**1,000**	1,000
4.95% Senior Notes due 2025	**1,000**	–
Unamortized discount	**(4)**	(1)
Total long-term debt	$ **4,663**	$ 2,466
Total debt	$ **4,664**	$ 6,967

(1) The bridge facility was repaid in full in January 2015 with proceeds from the issuance of $2.2 billion of long-term senior notes and $2.3 billion of common and mandatory convertible preferred stock.

(2) 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.

Commercial Paper

In April 2015, the Company entered into a commercial paper program. The Company may issue up to $2 billion in commercial paper under the program. However, outstanding borrowings from the commercial paper program combined with outstanding borrowings under the revolving credit facility may not exceed $2 billion. The commercial paper issuance may have terms of up to 397 days and will bear interest at rates agreed upon at the time of each issuance. The Company's short-term corporate credit ratings are currently A-3 by Standard & Poor's, P-3 by Moody's and F3 by Fitch Investor Services. As of September 30, 2015, the Company had $520 million of outstanding issuance under its commercial paper program at an average rate of 1.266%. As the Company has the intent, if necessary, and ability to refinance the balance due with borrowings under its revolving credit facility, the $520 million outstanding under the commercial paper program was classified as long-term debt on the September 30, 2015 unaudited condensed consolidated balance sheet.

Public Offering of 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 billion aggregate principal amount of its 4.95% senior notes due 2025 (the "2025 Notes"), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. 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 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 nine months ended September 30, 2015.

Credit and Term Facilities

The Company's revolving credit facility, entered into in December 2013, provides a borrowing capacity of up to $2.0 billion and matures in December 2018, with options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon the Company's agreement with its participating lenders. The interest rate on the revolving credit facility is calculated based upon the Company's credit rating and is currently 150 basis points over the current LIBOR as of September 30, 2015. The revolving credit facility is unsecured and is not guaranteed by any subsidiaries of the Company. The revolving credit facility contains covenants imposing certain restrictions on the Company, including a financial covenant under which Southwestern may not issue 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 September 30, 2015, the Company was in compliance with the covenants of its revolving credit facility and other debt agreements.

On December 19, 2014, the Company entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility, prior to its termination, required prepayment under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business. The term loan facility was repaid in full in April 2015 with proceeds from the divestiture of the Company's northeast Pennsylvania gathering assets and borrowings under the Company's revolving credit facility.

(10) COMMITMENTS AND CONTINGENCIES

Operating Commitments and Contingencies

In the first quarter of 2010, the Company was awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require the Company to make certain capital investments in New Brunswick of approximately $47 million Canadian dollars in the aggregate over the license periods. In order to obtain the licenses, the Company provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $45 million Canadian dollars. The promissory notes secure the Company's capital expenditure obligations under the licenses and are returnable to the Company to the extent the Company performs such obligations. If the Company fails to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. The Company commenced its Canada exploration program in 2010 and, as of September 30, 2015 has invested $45 million Canadian dollars, or $44 million US dollars, in New Brunswick towards the Company's commitment, fully covering the promissory notes held by the Province of New Brunswick. No liability has been recognized in connection with the promissory notes due to the Company's investments in New Brunswick as of September 30, 2015 and its future investment plans. In December 2014, New Brunswick's provincial government announced its intent to impose a moratorium on hydraulic fracturing in the province, and, on March 27, 2015, the provincial legislature approved enabling legislation. The Company has been granted an extension of its licenses. The provincial government has announced a list of conditions that must be met before the moratorium can be lifted, but because these conditions are subjective and the government has discretion whether to grant an extension, the Company cannot predict the duration of the moratorium or whether it will continue beyond the expiration of the licenses, as their terms have been, or in the future may be, extended. Unless and until the moratorium is lifted, the Company will not be able to continue with its program in New Brunswick. If the licenses expire before the moratorium is lifted or the Company can complete its program, the Company may be required to write off its investment.

As of September 30, 2015, the Company's contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on operational natural gas and liquids pipelines and gathering systems totaled approximately $8.8 billion, 36% 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 $605 million of that amount.

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 reported results of operations of the Company.

Litigation

The Company is subject to laws and regulations relating to the protection of the environment. The Company's policy is to accrue environmental and cleanup related costs of a non-capital nature 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, results of operations, and cash flows.

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., pending in the 273rd District Court in Shelby County, Texas. By the time of trial in December 2010, Ms. Berry-Helfand (the only remaining plaintiff) alleged that, in 2005, she provided our subsidiary with proprietary data regarding two prospects in the James Lime formation pursuant to a confidentiality agreement and that the Company's subsidiary refused to return the proprietary data to the plaintiff, subsequently acquired leases based upon such proprietary data and profited therefrom. Among other things, she alleged various statutory and common law claims, including, but not limited to, claims of misappropriation of trade secrets, violation of the Texas Theft Liability Act, breach of fiduciary duty and confidential relationships, various fraud based claims and breach of contract, including a claim of breach of a purported right of first refusal on all interests acquired by our subsidiary between February 2005 and February 2006. She also sought disgorgement of the Company's subsidiary's profits. A former associate of the plaintiff intervened in the matter claiming to have helped develop the prospect years earlier.

The jury found in favor of the plaintiff and the intervenor with respect to all of the statutory and common law claims and awarded $11 million in compensatory damages but no special, punitive or other damages. Separately, the jury determined that the Company's subsidiary's profits for purposes of disgorgement, if ordered as a remedy, were $382 million. (Disgorgement of profits is an equitable remedy determined by the judge, and it is within the judge's discretion to award none, some or all of unlawfully obtained profits.) In August 2011, a judgment was entered pursuant to which the plaintiff and the intervenor were entitled to recover approximately $11 million in actual damages and approximately $24 million in disgorgement as well as prejudgment interest and attorneys' fees, which currently are estimated to be up to $9 million, and all costs of court of the plaintiff and intervenor.

Both sides appealed and in July 2013, the Tyler Court of Appeals ordered that (1) the judgment awarding the plaintiff and the intervenor $24 million as disgorgement of illicit gains be reversed and judgment rendered that they take nothing, (2) the award of $11 million for actual damages, insofar as it is based on the jury's findings of breach of fiduciary duty, fraud, breach of contract, and theft of trade secret is reversed and judgment rendered that the plaintiff and the intervenor take nothing under those theories of recovery, (3) the award of $11 million to the plaintiff and the intervenor as damages for misappropriation of trade secret is affirmed, (4) the case be remanded to the trial court for a determination and award of attorney's fees for the Company's subsidiary as the prevailing party under the Texas Theft Liability Act, and (5) in all other respects, the judgment is affirmed. All parties petitioned for rehearing. The Tyler Court of Appeals denied rehearing in November 2013.

The Company's subsidiary filed a petition for review in the Supreme Court of Texas in February 2014. The plaintiff and the intervenor filed a cross-petition for review in April 2014, but conditioned their filing on the court's granting the Company's subsidiary's petition for review; i.e., if the court denies the Company's subsidiary's petition for review, then the plaintiff and the intervenor are not seeking further review of the court of appeals' judgment. The Supreme Court granted the parties' petitions for review and heard oral argument on the case in October 2015 but has not yet issued a decision. Based on the Company's understanding and judgment of the facts and merits of this case, including appellate matters, 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. If the Supreme Court affirms all aspects of the court of appeals' judgment, then the Company's subsidiary would owe the $11 million in damages, plus interest and attorneys' fees, offset by any award of attorneys' fees for its prevailing on the theft count. The Company's assessment may change in the future depending on the Supreme Court's decision, 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

The Company or 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 our 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 are appealing those orders. In October 2015, the court in the federal case conducted a hearing on the plaintiff's motion to certify a class of royalty owners not included in either of the two state cases. The Company and certain of its subsidiaries asserted that the federal court should not certify any class, but that, if it did, it should certify a broader class that would, among other things, encompass all cost-bearing royalty owners with leases for property in the Fayetteville Shale. The federal court has not yet ruled on this issue.

Discovery regarding the plaintiffs' theories of liability and amount of claimed damages is ongoing. None of the plaintiffs in any of the cases has specified the specific range of damages being sought, but each has presented two alternative damages theories. Under one theory, plaintiffs have asserted that obligations to affiliates are not "incurred" and therefore the exploration subsidiary was not entitled to deduct any post-production costs. Plaintiffs appear to contend that damages under this theory would be based on the aggregate amount deducted from royalty payments for gathering, treating, and compressing gas, which, based on discovery, could exceed $200 million. Under another theory, plaintiffs assert that the gathering and treating rates it deducted from royalty payments exceeded the affiliates' actual costs or otherwise were not reasonable. The plaintiffs have not disclosed what they contend the appropriate rate is.

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.

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.

Other

The Company is subject to various other 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.

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.

(11) 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 nine months ended September 30, 2015 and 2014:

	Pension Benefits			
	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions)			
Service cost	**$ 4**	$ 3	**$ 12**	$ 10
Interest cost	**1**	1	**4**	4
Expected return on plan assets	**(2)**	(1)	**(6)**	(5)
Amortization of prior service cost	**–**	–	**–**	–
Amortization of net loss	**1**	–	**2**	–
Net periodic benefit cost	**$ 4**	$ 3	**$ 12**	$ 9

The Company's postretirement benefit plan had a net periodic benefit cost of $1, $1, $3 and $2 million as of the three months ended September 30, 2015 and 2014, and nine months ended September 30, 2015 and 2014, respectively. As of September 30, 2015, the Company has contributed $9 million to the pension plan and expects to contribute an additional $3 million to the pension plan in 2015.

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 45,990 shares at September 30, 2015 compared to 11,055 shares at December 31, 2014.

(12) STOCK-BASED COMPENSATION

The Company recognized the following amounts in employee stock-based compensation costs for the three and nine months ended September 30, 2015 and 2014:

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions)			
Stock-based compensation cost – expensed	**$ 6**	$ 4	**$ 18**	$ 13
Stock-based compensation cost – capitalized	**$ 6**	$ 4	**$ 17**	$ 13

As of September 30, 2015, there was $80 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 2 years.

The following table summarizes stock option activity for the nine months ended September 30, 2015 and provides information for options outstanding and options exercisable as of September 30, 2015:

	Number of Options		Weighted Average Exercise Price
	(in thousands)		(per share)
Outstanding at December 31, 2014	3,622	$	35.41
Granted	224		26.35
Exercised	–		–
Forfeited or expired	(67)		38.97
Outstanding at September 30, 2015	**3,779**	**$**	**34.82**
Exercisable at September 30, 2015	**2,249**	**$**	**36.17**

The following table summarizes restricted stock activity for the nine months ended September 30, 2015 and provides information for unvested shares as of September 30, 2015:

	Number of Shares		Weighted Average Grant Date Fair Value
	(in thousands)		(per share)
Unvested shares at December 31, 2014	2,376	$	34.00
Granted	103		26.05
Vested	(98)		34.96
Forfeited	(70)		33.54
Unvested shares at September 30, 2015	**2,311**	**$**	**33.61**

The following table summarizes performance unit activity to be paid out in Company stock for the nine months ended September 30, 2015 and provides information for unvested units as of September 30, 2015. The performance units 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 the 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 grant date fair value is calculated using the Performance Measures and the closing price of the Company's common stock at the grant date.

	Number of Units [(1)]		Weighted Average Grant Date Fair Value
	(in thousands)		(per unit)
Unvested units at December 31, 2014	223	$	40.44
Granted	443		35.22
Vested	–		–
Forfeited	–		–
Unvested units at September 30, 2015	**666**	**$**	**36.97**

(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 Performance Measures.

Liability-Classified Performance Units

Certain employees were provided performance units vesting equally over three years. The payout of these units is 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, is paid in cash. As of September 30, 2015 and December 31, 2014, the Company's liability under the performance unit agreements was $24 million and $51 million, respectively.

(13) SEGMENT INFORMATION

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

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1 of the Notes to Consolidated Financial Statements included in Item 8 of the 2014 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 Services	Other	Total
		(in millions)		
Three months ended September 30, 2015:				
Revenues from external customers	**$ 491**	**$ 258**	**$ –**	**$ 749**
Intersegment revenues	**(3)**	**489**	**–**	**486**
Operating income (loss)	**(2,910)**	**68**	**–**	**(2,842)**
Gain on derivatives	**15**	**–**	**–**	**15**
Depreciation, depletion and amortization	**255**	**20**	**–**	**275**
Impairment of natural gas and oil properties	**2,839**	**–**	**–**	**2,839**
Provision (benefit) for income taxes [(1)]	**(1,112)**	**24**	**–**	**(1,088)**
Assets	**9,159**	**1,329**	**237** [(2)]	**10,725**
Capital investments [(3)]	**461**	**7**	**–**	**468**
Three months ended September 30, 2014:				
Revenues from external customers	$ 652	$ 276	$ –	$ 928
Intersegment revenues	3	707	–	710
Operating income	189	97	–	286
Gain (loss) on derivatives	79	–	(1)	78
Depreciation, depletion and amortization	223	15	–	238
Interest expense [(1)]	10	2	1	13
Provision (benefit) for income taxes [(1)]	107	34	(1)	140
Assets	7,461	1,494	222 [(2)]	9,177
Capital investments [(3)]	531	34	9	574

	Exploration and Production	Midstream Services	Other	Total
	(in millions)			
Nine months ended September 30, 2015:				
Revenues from external customers	$ **1,647**	$ **798**	$ **1**	$ **2,446**
Intersegment revenues	**(14)**	**1,653**	**–**	**1,639**
Operating income (loss)	**(4,471)**	**511**	**(1)**	**(3,961)**
Other income, net	**2**	**–**	**–**	**2**
Gain (loss) on derivatives	**32**	**–**	**(2)**	**30**
Depreciation, depletion and amortization	**824**	**52**	**–**	**876**
Impairment of natural gas and oil properties	**4,374**	**–**	**–**	**4,374**
Interest expense (1)	**45**	**7**	**–**	**52**
Provision (benefit) for income taxes (1)	**(1,724)**	**193**	**(1)**	**(1,532)**
Assets	**9,159**	**1,329**	**237** (2)	**10,725**
Capital investments (3)	**1,880**	**164**	**10**	**2,054**
Nine months ended September 30, 2014:				
Revenues from external customers	$ 2,169	$ 907	$ –	$ 3,076
Intersegment revenues	13	2,437	–	2,450
Operating income (loss)	817	272	(1)	1,088
Other income, net	1	–	–	1
Loss on derivatives	(27)	(1)	(1)	(29)
Depreciation, depletion and amortization	650	43	–	693
Interest expense (1)	29	9	1	39
Provision (benefit) for income taxes (1)	309	101	(1)	409
Assets	7,461	1,494	222 (2)	9,177
Capital investments (3)	1,706	109	22	1,837

(1) Interest expense and the provision for income taxes by segment are allocated as they are incurred at the corporate level.

(2) Other assets represent corporate assets not allocated to segments and assets for non-reportable segments.

(3) Capital investments includes a $6 million increase and a $53 million increase for the three months ended September 30, 2015 and 2014, respectively, and a $5 million decrease and a $114 million increase for the nine months ended September 30, 2015 and 2014, respectively, relating to the change in accrued expenditures between periods. E&P capital for the nine month period ended September 30, 2015 includes approximately $516 million related to the WPX Property and Statoil Property Acquisitions. Midstream capital for the nine months ended September 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 Services segment are $414 million and $612 million for the three months ended September 30, 2015 and 2014, respectively, and $1.4 billion and $2.2 billion for the nine months ended September 30, 2015 and 2014, respectively, for marketing of the Company's E&P sales. Corporate assets include cash and cash equivalents, furniture and fixtures, prepaid debt and other costs. Corporate general and administrative costs, depreciation expense and taxes other than income are allocated to the segments. The Company's E&P segment assets included $69 million and $78 million at September 30, 2015 and 2014, respectively, related to the Company's activities in Canada.

(14) NEW ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

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 April 2015, the FASB proposed to delay the effective date one year. The proposal was approved in July 2015. For public entities, Update 2014-09 is 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 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or 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 is effective for annual reporting periods beginning after December 15, 2015 including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2014-16 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

In April 2015, the FASB issued Accounting Standards Update No. 2015-03, Interest-Imputation of Interest (Subtopic 835-30) ("Update 2015-03"), which seeks to simplify presentation of debt issuance costs. Update 2015-03 requires 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 are not affected by the amendments in this Update. Entities should apply the amendments in Update 2015-03 on a retrospective basis, wherein the balance sheet of each individual period presented should be 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 addresses 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 are effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company is currently evaluating the provisions of Update 2015-03 and Update 2015-15 to assess the impact, if any, they may have on its consolidated results of operations, financial position or cash flows.

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 is currently evaluating the provisions of Update 2015-07 and assessing the impact, if any, it 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 prices 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 July 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-12, which consists of three related parts: (1) Plan Accounting: Defined Contribution Pension Plans (Topic 962); Health and Welfare Benefit Plans (Topic 965): Fully Benefit-Responsive Investment Contracts ("Part I"); (2) Plan Accounting: Defined Benefit Pension Plans (Topic 960); Defined Contribution Pension Plans (Topic 962); Health and Welfare Benefit Plans (Topic 965): Plan Investment Disclosures ("Part II"); and (3) Plan Accounting: Defined Benefit Pension Plans (Topic 960); Defined Contribution Pension Plans (Topic 962); Health and Welfare Benefit Plans (Topic 965): Measurement Date Practical Expedient ("Part III"). Part I requires (1) fully benefit-responsive investment contracts to be measured at contract value; and (2) an adjustment to reconcile contract value to fair value, when these measures differ, on the face of the plan financial statements. Part II eliminates the current requirement for both participant-directed investments and non-participant-directed investments to disclose individual investments representing 5% or more of net assets available for benefits, as well as the net appreciation or depreciation for investments by general type on a disaggregated basis. Part III permits plans to measure investments and investment-related accounts as of a month-end date that is closest to the plan's fiscal year-end, when the fiscal period does not coincide with a month-end. The amendments in Update 2015-12 are effective for fiscal years beginning after December 15, 2015, with early adoption permitted. The Company is currently evaluating the provisions of Update 2015-12 and assessing the impact, if any, it may have on its consolidated results of operations, financial position, or 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 are effective for fiscal years beginning after December 15, 2015, including interim periods within those fiscal years. The Company is currently evaluating the provisions of Update 2015-16 and assessing the impact, if any, it may have on its consolidated results of operations, financial position or cash flows.

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 2014 Annual Report and analyzes the changes in the results of operations between the three and nine months ended September 30, 2015 and 2014. 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 2014 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 2014 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, or E&P. We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services. We operate principally in two segments: E&P and Midstream Services.

Our primary business is the exploration for and production of natural gas and oil, with our current operations principally focused within the United States on development of unconventional reservoirs located in Arkansas, Pennsylvania and West Virginia. Our operations in Arkansas are primarily focused on an unconventional natural gas reservoir known as the Fayetteville Shale, and our operations in northeast Pennsylvania are focused on an unconventional natural gas reservoir known as the Marcellus Shale (herein referred to as "Northeast Appalachia"). We also have a significant stake in properties located in West Virginia and adjacent areas in southwest Pennsylvania. These operations, primarily in West Virginia, are focused on the Marcellus, the Utica and the Upper Devonian unconventional natural gas and oil reservoirs (herein referred to as "Southwest Appalachia"). To a lesser extent, we have exploration and production activities ongoing in Colorado, Louisiana and elsewhere in the United States. We also actively seek to find and develop new natural gas and oil plays with significant exploration and exploitation potential, which we refer to as "New Ventures," and to obtain additional reserves through acquisitions. We also operate drilling rigs in Arkansas, Pennsylvania and West Virginia, and provide oilfield products and services, principally serving our exploration and production operations. Our natural gas gathering and marketing ("Midstream Services") activities primarily support our E&P activities in Arkansas, Pennsylvania, Louisiana, and West Virginia.

We are focused on providing long-term growth in the net asset value per share of our business. We derive the majority of our operating income and cash flow from the production associated with our E&P business and expect this to continue in the future. We expect our production volumes will continue to increase due to the ongoing development of our Northeast and Southwest Appalachia properties. The price we expect to receive for our production is a critical factor in the capital investments we make in order to develop our properties. In recent years, there has been significant volatility in natural gas prices as evidenced by New York Mercantile Exchange, or NYMEX, natural gas prices ranging from a high of $13.58 per MMBtu in 2008 to a low of $1.91 per MMBtu in 2012 with wider fluctuations recently seen at regional pricing points reflecting basis differentials. Since the second half of 2014, the industry has faced an increasingly challenging commodity price environment. While we believe there may be improving supply and demand dynamics in the future, we will continue to exercise flexibility and discretion with our capital investment program. 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. Going forward, we will be impacted by crude oil and natural gas liquids ("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. Considering price impacts only and using the first-day-of-the-month prices of natural gas, oil and NGLs for the first ten months of 2015 and forecast prices for the remainder of 2015, we expect that a material amount of our proved undeveloped reserves at December 31, 2014 will be revised downward at year-end 2015. Our proved undeveloped reserves were approximately 45% of our total proved reserves at December 31, 2014. Using the same pricing scenario to determine the ceiling amount in our full cost ceiling test is likely to result in a material write-down in the fourth quarter of 2015 similar in magnitude to the write-down in the second quarter of 2015 ($944 million, net of tax), or larger, before consideration of moves from unevaluated properties.

Three Months Ended September 30, 2015 Compared with Three Months Ended September 30, 2014

We reported a net loss attributable to common stock of $1.8 billion for the three months ended September 30, 2015, or ($4.62) per diluted share, compared to net income attributable to common stock of $211 million, or $0.60 per diluted share, for the three months ended September 30, 2014.

Our natural gas and liquids production increased to 249 Bcfe for the three months ended September 30, 2015, up 27% from 196 Bcfe for the three months ended September 30, 2014. This 53 Bcfe increase was due to a 37 Bcfe increase in net production from our Southwest Appalachia properties, a 27 Bcf increase in net production from our Northeast Appalachia properties, and was partially offset by an 11 Bcfe decrease in net production from our Fayetteville Shale and other properties. The average price realized for our gas production, including the effects of hedges, decreased 36% to $2.21 per Mcf for the three months ended September 30, 2015 compared to $3.43 per Mcf for the same period in 2014. The average price realized for our oil production decreased 66% to $33.50 per barrel for the three months ended September 30, 2015 compared to $97.71 for the same period in 2014. The average price realized for our NGL production decreased 87% to $4.72 per barrel for the three months ended September 30, 2015 compared to $35.57 for the same period in 2014. We did not hedge our 2015 or 2014 oil or NGL production.

Our E&P segment reported an operating loss of $2.9 billion for the three months ended September 30, 2015, down from operating income of $189 million for the three months ended September 30, 2014. This decrease was primarily due to a $2.8 billion non-cash ceiling test impairment, a 45%, or $1.44 per Mcf, decrease in our realized natural gas price excluding hedges, decreases in our realized oil and NGL prices, and a $93 million increase in operating costs and expenses, excluding the ceiling test impairment, that resulted from increased activity levels, partially offset by an increase in the revenue impact of our 27%, or 53 Bcfe increase in production and an increase in hedge settlement proceeds. 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 loss and $5 million in operating income for the three months ended September 30, 2015 and 2014, respectively.

Operating income for our Midstream Services segment was $68 million for the three months ended September 30, 2015, down from $97 million for the three months ended September 30, 2014, due to a $26 million decrease in gas gathering revenues, a $3 million decrease in the margin generated from our natural gas and liquids marketing activities, and a $1 million loss on sale of assets, slightly offset by a $1 million decrease in operating costs and expenses. In April 2015, we sold our northeastern Pennsylvania gathering assets that accounted for $8 million in operating income for the three months ended September 30, 2014.

Capital investments were $468 million for the three months ended September 30, 2015 of which $461 million was invested in our E&P segment, compared to $574 million for the same period of 2014, of which $531 million was invested in our E&P segment.

Nine Months Ended September 30, 2015 Compared with Nine Months Ended September 30, 2014

We reported a net loss attributable to common stock of $2.5 billion for the nine months ended September 30, 2015, or ($6.65) per diluted share, compared to net income attributable to common stock of $612 million, or $1.74 per diluted share, for the nine months ended September 30, 2014.

Our natural gas and liquids production increased to 727 Bcfe for the nine months ended September 30, 2015, up 28% from 567 Bcfe for the nine months ended September 30, 2014. This 160 Bcfe increase was due to a 103 Bcfe increase in net production from our Southwest Appalachia properties, a 78 Bcf increase in net production from our Northeast Appalachia properties, and was partially offset by a 21 Bcfe decrease in net production from our Fayetteville Shale and other properties. The average price realized for our gas production, including the effects of hedges, decreased 35% to $2.47 per Mcf for the nine months ended September 30, 2015 compared to $3.79 per Mcf for the same period in 2014. The average price realized for our oil production decreased 65% to $35.23 per barrel for the nine months ended September 30, 2015 compared to $100.39 for the same period in 2014. The average price realized for our NGL production decreased 84% to $6.43 per barrel for the nine months ended September 30, 2015 compared to $40.73 for the same period in 2014. We did not hedge our 2015 or 2014 oil or NGL production.

Our E&P segment reported an operating loss of $4.5 billion for the nine months ended September 30, 2015, down from operating income of $817 million for the nine months ended September 30, 2014. This decrease was primarily due to a $4.4 billion non-cash ceiling test impairment, a 48%, or $1.86 per Mcf, decrease in our realized natural gas price excluding hedges, decreases in our realized oil and NGL prices, and a $365 million increase in operating costs and expenses, excluding the ceiling test impairment, that resulted from increased activity levels, partially offset by an increase in the revenue impact of our 28%, or 160 Bcfe, increase in production and an increase in hedge settlement proceeds. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for $24 million in operating income for the nine months ended September 30, 2014.

Operating income for our Midstream Services segment was $511 million for the nine months ended September 30, 2015, up from $272 million for the nine months ended September 30, 2014, due to a $277 million net gain on sale of assets and a $3 million increase in the margin generated from our natural gas and liquids marketing activities, partially offset by a decrease of $38 million in gas gathering revenues and an increase in operating costs and expenses of $3 million. In April 2015, we sold our northeastern Pennsylvania gathering assets that accounted for $13 million and $27 million in operating income for the nine months ended September 30, 2015 and 2014, respectively. A gain on sale of $283 million was recognized and is included in (Gain) loss on sale of assets, net in the unaudited condensed consolidating statement of operations.

Capital investments were $2.1 billion for the nine months ended September 30, 2015 (including $635 million, in total, related to the acquisitions from WPX Energy, Inc. and Statoil ASA) of which $1.9 billion was invested in our E&P segment, compared to $1.8 billion for the same period of 2014, of which $1.7 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 September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
Revenues (in millions)	**$ 488**	$ 655	**$ 1,633**	$ 2,182
Impairment of natural gas and oil properties (in millions)	**$ 2,839**	$ –	**$ 4,374**	$ –
Operating costs and expenses (in millions)	**$ 559**	$ 466	**$ 1,730**	$ 1,365
Operating income (loss) (in millions)	**$ (2,910)**	$ 189	**$ (4,471)**	$ 817
Gain (loss) on derivatives (in millions) (1)	**$ 50**	$ 24	**$ 138**	$ (21)
Gas production (Bcf)	**228**	196	**673**	566
Oil production (MBbls)	**562**	51	**1,696**	114
NGL production (MBbls)	**3,034**	11	**7,374**	27
Total production (Bcfe)	**249**	196	**727**	567
Average realized gas price per Mcf, including hedges (2)	**$ 2.21**	$ 3.43	**$ 2.47**	$ 3.79
Average realized gas price per Mcf, excluding hedges	**$ 1.77**	$ 3.21	**$ 2.05**	$ 3.91
Average oil price per Bbl	**$ 33.50**	$ 97.71	**$ 35.23**	$ 100.39
Average NGL price per Bbl	**$ 4.72**	$ 35.57	**$ 6.43**	$ 40.73
Average unit costs per Mcfe:				
Lease operating expenses	**$ 0.92**	$ 0.91	**$ 0.92**	$ 0.91
General and administrative expenses	**$ 0.20**	$ 0.23	**$ 0.22**	$ 0.24
Taxes, other than income taxes	**$ 0.10**	$ 0.10	**$ 0.11**	$ 0.11
Full cost pool amortization	**$ 0.98**	$ 1.09	**$ 1.08**	$ 1.10

(1) Represents the gain (loss) on derivatives, settled, associated with derivatives not designated for hedge accounting.

(2) Including the gain (loss) on derivatives excluding derivatives, settled effects of commodity hedging contracts not designated for hedge accounting, results in an average price of $2.07, $3.71, $2.32 and $3.78 per Mcf for the three months ended September 30, 2015 and 2014, and the nine months ended September 30, 2015 and 2014, respectively.

Revenues

Revenues for our E&P segment were $488 million for the three months ended September 30, 2015, down $167 million, or 25%, compared to the same period in 2014. A decrease in the price realized from the sale of our natural gas decreased revenue by $325 million, partially offset by an increase of $102 million due to higher natural gas production volumes and an increase of $29 million in hedge settlement proceeds. Additionally, there was a $157 million increase due to increased liquid production volumes, partially offset by a $130 million decrease as a result of decreased liquids pricing. E&P revenues were $1.6 billion for the nine months ended September 30, 2015, down $549 million, or 25%, compared to the same period in 2014. A decrease in the price realized from the sale of our natural gas decreased revenue by $1,251 million, partially offset by a $416 million increase due to higher natural gas production volumes and an increase of $192 million in hedge settlement proceeds. Additionally there was a $458 million increase due to increased liquid production volumes, partially offset by a $364 million decrease as a result of decreased liquids pricing. We expect our production volumes to continue to increase due to the development of our Northeast and Southwest Appalachia properties. Natural gas, oil, and NGL prices are difficult to predict and are subject to wide price fluctuations. As of September 30, 2015, we had hedged 60 Bcf of our remaining 2015 natural gas production to limit our exposure to price fluctuations. We refer you to Note 6 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 $16 million of our oil and gas revenues for the three months ended September 30, 2014, and $15 and $56 million of our oil and gas revenues for the nine months ended September 30, 2015 and 2014, respectively.

Production

For the three months ended September 30, 2015, our natural gas and liquids production increased 27% to 249 Bcfe, up from 196 Bcfe from the same period in 2014, and was produced entirely by our properties in the United States. The 53 Bcfe increase in our 2015 production was due to a 37 Bcfe increase in net production from our Southwest Appalachia properties, a 27 Bcf increase in net production from our Northeast Appalachia properties, and was partially offset by an 11 Bcfe decrease in net production in our Fayetteville Shale and other properties. Net production from our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia properties was 118 Bcf, 93 Bcf and 37 Bcfe respectively, for the three months ended September 30, 2015 compared to 126 Bcf, 66 Bcf, and zero, respectively, for the same period in 2014. For the nine months ended September 30, 2015, our natural gas and liquids production increased 28% to 727 Bcfe, up from 567 Bcfe from the same period in 2014, and was produced entirely by our properties in the United States. The 160 Bcfe increase in our 2015 production was due to a 103 Bcfe increase in net production from our Southwest Appalachia properties, a 78 Bcf increase in net production from our Northeast Appalachia properties, and was partially offset by a 21 Bcfe decrease in net production in our Fayetteville Shale and other properties. Net production from our Fayetteville Shale, Northeast Appalachia and Southwest Appalachia properties was 354 Bcf, 263 Bcf and 103 Bcfe respectively, for the nine months ended September 30, 2015 compared to 369 Bcf, 185 Bcf, and zero, respectively, for the same period in 2014.

Commodity Prices

The average price realized for our natural gas production, including the effects of hedges, decreased to $2.21 per Mcf for the three months ended September 30, 2015, as compared to $3.43 for the same period in 2014. The decrease was the result of a $1.44 per Mcf decrease in the average natural gas price, excluding hedges, partially offset by higher proceeds from our hedge program during the three months ended September 30, 2015 as compared to the same period in 2014. The average price realized for our natural gas production, excluding the effects of hedges, decreased 45% to $1.77 per Mcf for the three months ended September 30, 2015, as compared to the same period in 2014. Our hedges increased the average realized natural gas price by $0.44 per Mcf for the three months ended September 30, 2015 compared to an increase of $0.22 per Mcf for the same period in 2014. The average price realized for our natural gas production, including the effects of hedges, decreased to $2.47 per Mcf for the nine months ended September 30, 2015, as compared to $3.79 for the same period in 2014. The decrease was the result of a $1.86 per Mcf decrease in the average natural gas price, excluding hedges, partially offset by higher proceeds from our hedge program during the nine months ended September 30, 2015 as compared to the same period in 2014. The average price realized for our natural gas production, excluding the effects of hedges, decreased 48% to $2.05 per Mcf for the nine months ended September 30, 2015, as compared to the same period in 2014. Our hedges increased the average realized natural gas price by $0.42 per Mcf for the nine months ended September 30, 2015 compared to a decrease of $0.12 per Mcf for the same period in 2014.

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

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 charges 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.

Excluding the impact of hedges, the average price received for our natural gas production for the nine months ended September 30, 2015 of $2.05 per Mcf was approximately $0.75 lower than the average monthly NYMEX settlement price, primarily due to locational basis differentials and transportation costs. We protected approximately 44% of our natural gas production for the nine months ended September 30, 2015 from the impact of widening basis differentials through our hedging activities and sales arrangements. At September 30, 2015, we had basis protected on approximately 82 Bcf of our remaining 2015 expected natural gas production through physical sales arrangements and financial hedging activities at a differential to NYMEX natural gas prices of approximately ($0.17) per Mcf, excluding transportation and fuel charges. In addition to the basis hedges at September 30, 2015, we had NYMEX fixed price hedges in place on notional volumes of 60 Bcf of our remaining 2015 natural gas production at an average price of $4.40 per MMBtu. Natural gas accounted for approximately 92% and 100% of our total production for the nine months ended September 30, 2015 and 2014, respectively.

We realized an average sales price of $33.50 per barrel for our oil production for the three months ended September 30, 2015, down approximately 66% from $97.71 per barrel for the same period in 2014. We realized an average sales price of $35.23 per barrel for our oil production for nine months ended September 30, 2015, down approximately 65% from $100.39 per barrel for the same period in 2014. We did not hedge our 2015 or 2014 oil production. Oil accounted for 1% and less than 1% of our total production for the nine months ended September 30, 2015 and 2014, respectively.

We realized an average sales price of $4.72 per barrel for our NGL production for the three months ended September 30, 2015, down approximately 87% from $35.57 per barrel for the same period in 2014. We realized an average sales price of $6.43 per barrel for our NGL production for nine months ended September 30, 2015, down approximately 84% from the $40.73 per barrel for the same period in 2014. We did not hedge our 2015 or 2014 NGL production. NGLs accounted for 7% and less than 1% of our total production for the nine months ended September 30, 2015 and 2014, respectively.

Operating Income

Our E&P segment reported an operating loss of $2.9 billion for the three months ended September 30, 2015, down from operating income of $189 million for the three months ended September 30, 2014. This decrease was primarily due to a $2.8 billion non-cash ceiling test impairment, a 45%, or $1.44 per Mcf, decrease in our realized natural gas price excluding hedges, decreases in our realized oil and NGL prices, and a $93 million increase in operating costs and expenses, excluding the ceiling test impairment, that resulted from increased activity levels, partially offset by an increase in the revenue impact of our 27%, or 53 Bcfe, increase in production and an increase in hedge settlement proceeds. Our E&P segment reported operating loss of $4.5 billion for the nine months ended September 30, 2015, down from operating income of $817 million for the nine months ended September 30, 2014. This decrease was primarily due to a $4.4 billion non-cash ceiling test impairment, a 48%, or $1.86 per Mcf, decrease in our realized natural gas price, excluding hedges, decreases in our realized oil and NGL prices, and a $365 million increase in operating costs and expenses, excluding the ceiling test impairment, that resulted from increased activity levels, partially offset by an increase in the revenue impact of our 28%, or 160 Bcfe, increase in production and an increase in hedge settlement proceeds. In May 2015, we sold our conventional oil and gas assets located in East Texas and the Arkoma Basin that accounted for ($1), $5 and $24 million of our operating income (loss) for the three months ended September 30, 2015 and 2014, and nine months ended September 30, 2014, respectively.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.92 for the three months ended September 30, 2015 compared to $0.91 for the same period in 2014. Lease operating expense per unit of production increased for the three months ended September 30, 2015 as compared to the same period of 2014 primarily due to an increase in gathering and processing charges. Lease operating expenses per Mcfe for the E&P segment were $0.92 for the nine months ended September 30, 2015 compared to $0.91 for the same period in 2014. Lease operating expense per unit of production increased for the nine months ended September 30, 2015 as compared to the same period of 2014 primarily due to an increase in gathering and processing charges.

General and administrative expenses for the E&P segment were $0.20 per Mcfe for the three months ended September 30, 2015 compared to $0.23 per Mcfe for the same period in 2014 primarily due to an increase in production volumes. General and administrative expenses for the E&P segment were $0.22 per Mcfe for the nine months ended September 30, 2015 compared to $0.24 per Mcfe for the same period in 2014 primarily due to an increase in production volumes. In total, general and administrative expenses for the E&P segment were $50 million for the three months ended September 30, 2015, compared to $44 million for the three months ended September 30, 2014, primarily due to increased personnel costs associated with the expansion of our E&P operations due to the development of our Northeast and Southwest Appalachia assets. In total, general and administrative expenses for the E&P segment were $158 million for the nine months ended September 30, 2015, compared to $134 million for the nine months ended September 30, 2014, primarily due to increased personnel costs associated with the expansion of our E&P operations due to the development of our Northeast and Southwest Appalachia assets.

Taxes other than income taxes per Mcfe were $0.10 for the three months ended September 30, 2015 and 2014, and $0.11 for the nine months ended September 30, 2015 and 2014, respectively. 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 $0.98 per Mcfe for the three months ended September 30, 2015 compared to $1.09 for the same period in 2014. For the first nine months of 2015, our full cost pool amortization rate was $1.08 per Mcfe compared to $1.10 per Mcfe for the same period in 2014. 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 tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserve changes.

Unevaluated costs excluded from amortization were $4.9 billion at September 30, 2015 compared to $4.6 billion at December 31, 2014. The increase in unevaluated costs primarily resulted from the WPX Property and Statoil Property Acquisitions. Unevaluated costs excluded from amortization at September 30, 2015 included $69 million related to our properties in Canada, compared to $76 million at December 31, 2014.

Midstream Services

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	($ in millions, except volumes)			
Marketing revenues	**$ 630**	$ 840	**$ 2,072**	$ 2,927
Gas gathering revenues	**$ 117**	$ 143	**$ 379**	$ 417
Marketing purchases	**$ 615**	$ 822	**$ 2,025**	$ 2,883
Operating costs and expenses	**$ 63**	$ 64	**$ 192**	$ 189
Gain (loss) on sale of assets, net	**$ (1)**	$ –	**$ 277**	$ –
Operating income	**$ 68**	$ 97	**$ 511**	$ 272
Volumes marketed (Bcfe)	**288**	229	**837**	670
Volumes gathered (Bcf)	**186**	247	**620**	719

Revenues

Revenues from our marketing activities were down 25% to $630 million for the three months ended September 30, 2015 compared to the same period in 2014 and were down 29% to $2,072 million for the nine months ended September 30, 2015 compared to the same period in 2014. For the three months ended September 30, 2015, the price received for volumes marketed decreased 40% and the volumes marketed increased 26% compared to the same period in 2014. For the nine months ended September 30, 2015, the price received for volumes marketed decreased 43% and the volumes marketed increased 25% compared to the same period in 2014. 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 volumes marketed, production from our affiliated E&P operated wells accounted for 97% and 95%, respectively, of the marketed volumes for the three months ended September 30, 2015 and 2014. For the nine months ended September 30, 2015 and 2014, production from our affiliated E&P operated wells accounted for 97% and 98% of the marketed volumes, respectively. Our Midstream Services segment marketed approximately 64% of our combined oil and NGL production for the three months ended September 30, 2015 and 58% of our combined oil and NGL production for the nine months ended September 30, 2015.

Revenues from our gathering activities were down 18% to $117 million for the three months ended September 30, 2015 compared to the same period in 2014 and down 9% to $379 million for the nine months ended September 30, 2015 compared to the same period in 2014. The decrease in gathering revenues for the three and nine months ended September 30, 2015 was primarily due to the divestiture of our northeast Pennsylvania gathering assets in April 2015. The divested gathering assets accounted for $17 million of our gathering revenues for the three months ended September 30, 2014, and $21 and $49 million of our gathering revenues for the nine months ended September 30, 2015 and 2014, respectively.

Operating Income

Operating income from our Midstream Services segment decreased 30% to $68 million for the three months ended September 30, 2015 compared to $97 million for the same period in 2014 and increased 88% to $511 million for the nine months ended September 30, 2015 compared to $272 million for the same period in 2014. The $29 million decrease in operating income for the three months ended September 30, 2015 was due to a $26 million decrease in gas gathering revenues, a $3 million decrease in the margin generated from our natural gas and liquids marketing activities, and a $1 million loss on sale of assets, slightly offset by a $1 million decrease in operating costs and expenses. Included in the operating costs and expenses of the Midstream Services segment for the three months ended September 30, 2015 is $6 million for the amortization associated with the intangible asset related to the firm transportation acquired through the WPX property acquisition. The $239 million increase in operating income for the nine months ended September 30, 2015 was due to a $277 million net gain on sale of assets and an increase of $3 million in the margin generated from our natural gas and liquids marketing activities, partially offset by a decrease of $38 million in gas gathering revenues and an increase in operating costs and expenses of $3 million. Included in the operating costs and expenses of the Midstream Services segment for the nine months ended September 30, 2015 is $10 million for the amortization associated with the intangible asset related to the firm transportation acquired through the WPX property acquisition. In April 2015, we sold our northeastern Pennsylvania gathering assets that accounted for $8 million of our operating income for the three months ended September 30, 2014, and $13 and $27 million of our operating income for the nine months ended September 30, 2015 and 2014, respectively. A gain on this sale of $283 million was recognized and is included in (Gain) loss on sale of assets, net in the unaudited condensed consolidating statement of operations.

The margin generated from gas marketing activities was $15 million and $18 million for the three months ended September 30, 2015 and 2014, respectively. The margin generated from gas marketing activities was $47 million and $44 million for the nine months ended September 30, 2015 and 2014, respectively. Margins are driven primarily by volumes of natural gas 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. We refer you to Item 3, "Quantitative and Qualitative Disclosures About Market Risks" included in this Quarterly Report for additional information.

Interest Expense

For the three months ended September 30, 2015, we had no interest expense, net of capitalization, compared to $13 million for the same period in 2014. Interest expense, net of capitalization, increased to $52 million for the nine months ended September 30, 2015 compared to $39 million for the same period in 2014. The decrease in interest expense, net of capitalization, for the three months ended September 30, 2015 was primarily due to higher capitalized interest while the increase in interest expense, net of capitalization, for the nine months ended September 30, 2015 was primarily due to expensing $47 million in remaining unamortized fees associated with the repayment of our bridge facility in January 2015. We capitalized interest of $53 and $14 million for the three months ended September 30, 2015 and 2014, respectively, and capitalized interest of $155 and $40 million for the nine months ended September 30, 2015 and 2014, respectively. The increase in capitalized interest for the three and nine months ended September 30, 2015 compared to the same periods in 2014 was primarily due to an increase in our unevaluated property balance.

Gain (Loss) on Derivatives

At September 30, 2015, our basis swaps, certain fixed price swaps, fixed price call options and interest rate swaps were not designated for hedge accounting treatment. Changes in the fair value of derivatives that were not designated as cash flow hedges are recorded in gain (loss) on derivatives. For the nine months ended September 30, 2015, we recorded a gain on derivatives excluding derivatives, settled of $11 million related to fixed price call options not designated for hedge accounting treatment, a loss on derivatives excluding derivatives, settled of $110 million related to fixed price swaps not designated for hedge accounting, a loss on derivatives excluding derivatives, settled of $4 million related to basis swaps not designated for hedge accounting treatment and a loss on derivatives excluding derivatives, settled of $2 million related to interest rate swaps not designated for hedge accounting. Derivatives not designated for hedge accounting that were settled resulted in a gain of $135 million and a loss of $22 million for the nine months ended September 30, 2015 and 2014, respectively. In general and without consideration of volatility or duration, as 2015 natural gas prices increase from September 30, 2015 levels, we will recognize losses in future periods and, likewise, as 2015 natural gas prices decline from September 30, 2015 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 38% and 40% for the three months ended September 30, 2015 and 2014, respectively, and 38% and 40% for the nine months ended September 30, 2015 and 2014, respectively. For the three months ended September 30, 2015, we recorded an income tax benefit of $1.1 billion compared to an income tax expense of $140 million for the same period in 2014. For the nine months ended September 30, 2015, we recorded an income tax benefit of $1.5 billion compared to an income tax expense of $409 million for the same period in 2014.

Reconciliation of Non-GAAP Measures

We report our financial results in accordance with GAAP. However, management believes certain non-GAAP performance measures may provide users of this financial information additional meaningful comparisons between current results and the results of our peers and of prior periods.

We define adjusted EBITDA as net income plus interest, income tax expense, non-cash impairment of natural gas and oil properties, (gain) loss on asset sales, depreciation, depletion and amortization and (gain) loss on derivatives, excluding derivatives, settled. Management presents measures such as adjusted EBITDA because it is used by many investors and it is a financial measure commonly used in the energy industry. Adjusted EBITDA should not be considered in isolation or as a substitute for net income, net cash provided by operating activities or other income or cash flow data prepared in accordance with GAAP, or as a measure of the company's profitability or liquidity. Adjusted EBITDA as defined above may not be comparable to similarly titled measures of other companies. The table below reconciles Adjusted EBITDA, as defined, with net income.

	For the three months ended September 30,		For the nine months ended September 30,	
	2015	2014	**2015**	2014
	(in millions)			
Net income (loss) attributable to common stock	**$ (1,766)**	$ 211	**$ (2,528)**	$ 612
Mandatory convertible preferred stock dividend	**27**	–	**79**	–
Net income (loss)	**$ (1,739)**	$ 211	**$ (2,449)**	$ 612
Add back:				
Net interest expense	**–**	13	**52**	39
Provision (benefit) for income taxes	**(1,088)**	140	**(1,532)**	409
Depreciation, depletion and amortization	**275**	238	**876**	693
Impairment of natural gas and oil properties	**2,839**	–	**4,374**	–
(Gain) loss on sale of assets, net	**1**	–	**(276)**	–
(Gain) loss on derivatives excluding derivatives, settled	**34**	(54)	**105**	7
Adjusted EBITDA	**$ 322**	$ 548	**$ 1,150**	$ 1,760

New Accounting Standards Not Yet Implemented in this Report

Refer to Note 14 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 $2.0 billion revolving credit facility, funds accessed through commercial paper and capital markets as our primary sources of liquidity.

During 2015, depending on commodity prices, we plan to draw on a portion of the funds available under our revolving credit facility and our commercial paper program to fund the portion of our planned capital investments exceeding our operating cash flow (discussed below under "Capital Investments"). We refer you to Note 9 of the unaudited condensed consolidated financial statements included in this Quarterly Report and the section below under "Financing Requirements" for additional discussion of our revolving credit facility and commercial paper program.

Net cash provided by operating activities decreased 31% to $1.2 billion for the nine months ended September 30, 2015 down from $1.8 billion for the same period in 2014, due to a decrease in net income adjusted for non-cash expenses and changes in working capital accounts. During the nine months ended September 30, 2015, 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 nine months ended September 30, 2015, cash generated from our operating activities funded 60% of our cash requirements for capital investments, including acquisitions, compared to 97% for the same period in 2014.

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 and oil prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. The sales price we receive for our production is also influenced by our commodity hedging activities. See "Quantitative and Qualitative Disclosures about Market Risks" in Item 3 and Note 6 in 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 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.

The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the revolving credit facility. Although we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet our obligation.

Capital Investments

Our capital investments for the nine months ended September 30, 2015 were $2.1 billion, including $635 million, in total, related to the acquisitions from WPX Energy, Inc. ("WPX") and Statoil ASA ("Statoil"), and $1.8 billion for the nine months ended September 30, 2014. Our E&P segment investments were $1.9 billion and $1.7 billion for the nine months ended September 30, 2015 and 2014, respectively. Our E&P segment capitalized internal costs of $244 million for the nine months ended September 30, 2015 compared to $238 million for the comparable period in 2014. 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.

Excluding the capital associated with the closing of the WPX and Statoil acquisitions, our capital investments for 2015 are planned to be $1.9 billion, consisting of approximately $1.8 billion for E&P, $80 million for Midstream Services and $35 million for E&P services and corporate. Of the approximately $1.8 billion, we expect to allocate approximately $560 million to our Fayetteville Shale properties, approximately $605 million to our Northeast Appalachia properties, approximately $510 million to our Southwest Appalachia properties and approximately $85 million to our other properties. Our planned level of capital investments in 2015 is expected to allow us to continue our progress in the Fayetteville Shale and Northeast Appalachia programs, initiate our development program in Southwest Appalachia and explore and develop other existing natural gas and oil properties and generate new drilling prospects. Our 2015 capital investment program has been, and is expected to continue to be funded through cash flow from operations and borrowings under our revolving credit facility and commercial paper. The planned capital program for the remainder of 2015 is flexible, and we will reevaluate our proposed investments needed to take into account prevailing market conditions.

Financing Requirements

Our total debt outstanding was $4.7 billion at September 30, 2015 compared to $7.0 billion at December 31, 2014.

In April 2015, we entered into a commercial paper program. We may issue up to $2.0 billion in commercial paper under the program. However, outstanding borrowings from our commercial paper program combined with outstanding borrowings under our revolving credit facility may not exceed $2.0 billion. The commercial paper issuance may have terms of up to 397 days and will bear interest at rates agreed upon at the time of each issuance. Our short-term corporate credit ratings are currently A-3 by Standard & Poor's, P-3 by Moody's and F3 by Fitch Investor Services. As of September 30, 2015, we had $520 million of outstanding issuance under our commercial paper program at an average rate of 1.266%. As we have the intent, if necessary, and ability to refinance the balance due with borrowings under our revolving credit facility, the $520 million outstanding under the commercial paper program was classified as long-term debt on the September 30, 2015 unaudited condensed consolidated balance sheet.

In January 2015, we completed concurrent underwritten public offerings of 30,000,000 shares of our 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 discounts and offering expenses. The common stock offering was priced at $23.00 per share. 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 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 our $4.5 billion 364-day bridge facility, 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. 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 averaging 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 billion aggregate principal amount of our 4.95% senior notes due 2025 (the "2025 Notes"), with net proceeds from the offering totaling approximately $2.2 billion after underwriting discounts and offering expenses. 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 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 revolving credit facility.

In December 2014, we entered into a $500 million unsecured two-year term loan credit agreement with various lenders. The term loan facility required prepayments under certain circumstances from the net cash proceeds of sales of equity or certain assets and borrowings outside the ordinary course of business or for specified uses and was repaid in full in April 2015 principally with proceeds from the divestiture of our northeastern Pennsylvania gathering assets and borrowings under our revolving credit facility.

In December 2013, we entered into a credit agreement that exchanged our previous revolving credit facility. Under the revolving credit facility, we have a borrowing capacity of $2.0 billion. Our current revolving credit facility has a maturity date of December 2018 and options for two one-year extensions with participating lender approval. The amount available under the revolving credit facility may be increased by $500 million upon our agreement with our participating lenders. The interest rate on the revolving credit facility is determined based upon our public debt rating and is currently 150 basis points over LIBOR as of September 30, 2015. The revolving credit facility is unsecured and is not guaranteed by any of our subsidiaries. Contemporaneously with the execution of the credit agreement, in December 2013, we obtained releases of subsidiary guarantees under the 7.15%, 7.5%, 7.35%, 7.125% and 4.10% senior notes.

At September 30, 2015, we had a long-term issuer credit rating of BBB- by Standard & Poor's and Fitch Investor Services and a long-term debt rating of Baa3 by Moody's. Any downgrades in our public debt ratings by Standard & Poor's or Moody's could increase our cost of funds and decrease our liquidity under the revolving credit facility.

Our revolving credit facility contains covenants that impose certain restrictions on us. Under our revolving credit facility, we must keep our total debt at or below 60% of our total adjusted book capital. This financial covenant with respect to capitalization percentages excludes the effects of any non-cash impacts from any full cost ceiling impairments, certain non-cash hedging activities and our pension and other postretirement liabilities. Therefore, under our revolving credit facility, our adjusted capital structure as of September 30, 2015, was 36% debt and 64% equity. We were in compliance with all of the covenants of our revolving credit facility as of September 30, 2015. Although we do not anticipate any violations of our financial covenants, our ability to comply with these covenants are 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 oil. If we are unable to borrow under our revolving credit facility, we may have to decrease our capital investment plans.

At September 30, 2015, on a GAAP basis, our capital structure consisted of 51% debt and 49% equity (exclusive of cash and cash equivalents) and $15 million in cash and cash equivalents, compared to 60% debt and 40% equity and $53 million in cash and cash equivalents at December 31, 2014. Equity at September 30, 2015 included an accumulated other comprehensive income gain of $31 million related to our hedging activities offset by a $23 million loss in pension and other postretirement liabilities. The amount recorded in equity for our hedging activities is based on current market values for our hedges at September 30, 2015 and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged.

Our hedges allow us to ensure a certain level of cash flow to fund our operations. At October 20, 2015, we had NYMEX commodity price hedges in place on 60 Bcf of our remaining targeted 2015 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 September 30, 2015, 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 2014 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 2014 Annual Report.

Contingent Liabilities and Commitments

In the first quarter of 2010, we were awarded exclusive licenses by the Province of New Brunswick in Canada to conduct an exploration program covering approximately 2.5 million acres in the province. The licenses require us to make certain capital investments in New Brunswick of approximately $47 million Canadian dollars in the aggregate over the license periods. In order to obtain the licenses, we provided promissory notes payable on demand to the Minister of Finance of the Province of New Brunswick with an aggregate principal amount of $45 million Canadian dollars. The promissory notes secure our capital expenditure obligations under the licenses and are returnable to us to the extent we perform such obligations. If we fail to fully perform, the Minister of Finance may retain a portion of the applicable promissory notes in an amount equal to any deficiency. We commenced our Canada exploration program in 2010 and, as of September 30, 2015, have invested $45 million Canadian dollars, or $44 million US dollars, in New Brunswick towards our commitment, fully covering the promissory notes held by the Province of New Brunswick. No liability has been recognized in connection with the promissory notes due to our investments in New Brunswick as of September 30, 2015 and our future investment plans. In December 2014, New Brunswick's provincial government announced its intent to impose a moratorium on hydraulic fracturing in the province, and, on March 27, 2015, the provincial legislature approved enabling legislation. We have been granted an extension of our licenses. The provincial government has announced a list of conditions that must be met before the moratorium can be lifted, but because these conditions are subjective and the government has discretion whether to grant an extension, we cannot predict the duration of the moratorium or whether it will continue beyond the expiration of the licenses, as their terms have been, or in the future may be, extended. Unless and until the moratorium is lifted, we will not be able to continue with our program in New Brunswick. If the licenses expire before the moratorium is lifted or the Company can complete its program, the Company may be required to write off its investment.

As of September 30, 2015, our contractual obligations for demand and similar charges under firm transportation and gathering agreements to guarantee access capacity on operational natural gas and liquids pipelines and gathering systems totaled approximately $8.8 billion, 36% 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. We also had guarantee obligations of up to $605 million of that amount.

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. For the nine months ended September 30, 2015, we have contributed $9 million to the pension plan and expect to contribute an additional $3 million to the pension plan in 2015. At September 30, 2015, we recognized a liability of $48 million as a result of the underfunded status of our pension and other postretirement benefit plans compared to a liability of $44 million at December 31, 2014.

We are subject to litigation, claims and proceedings (including with respect to environmental matters) that arise in the ordinary course of business. Management believes, individually or in aggregate, such litigation, claims and proceedings will not have a material adverse impact on our financial position, results of operations, or cash flows, but these matters are subject to inherent uncertainties and 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.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described in "Financial Requirements" above. We had negative working capital of $212 million at September 30, 2015 and negative working capital of $4.3 billion at December 31, 2014. The negative working capital as of September 30, 2015 was primarily due to a decrease in derivative assets in 2015. The negative working capital as of December 31, 2014 was primarily due to the outstanding balance on our bridge facility, which was repaid in full in January 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 natural gas 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 nine months ended September 30, 2015. See “Commodities Risk” below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

At September 30, 2015, we had approximately $3.9 billion of outstanding senior notes with a weighted average interest rate of 4.818%, $280 million of borrowings under our revolving credit facility with a weighted average interest rate of 1.664%, and $520 million outstanding through our commercial paper program with an interest rate of 1.266%. We currently have an interest rate swap in effect to mitigate a portion of our exposure to volatility in interest rates.

Commodities Risk

We use over-the-counter natural gas and oil fixed price swap agreements and fixed price options to hedge 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).

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and oil. 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 hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major commercial banks, investment 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.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for natural gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At September 30, 2015, the net fair value of our financial instruments related to natural gas production was a $108 million asset.

Natural Gas (Bcf):	Volume (Bcf)	Weighted Average Fixed Price Swaps ($/MMBtu)	Weighted Average Ceiling Price ($/MMBtu)	Weighted Average Basis Differential ($/MMBtu)	Fair value at September 30, 2015 ($ in millions)
Fixed Price Swaps:					
2015	60	$ 4.40	$ –	$ –	$ 109
Basis Swaps:					
2015	4	$ –	$ –	$ 0.14	$ 2
2016	4	$ –	$ –	$ 0.72	$ (2)
Fixed Price Call Options:					
2015	50	$ –	$ 5.09	$ –	$ –
2016	120	$ –	$ 5.00	$ –	$ (1)

ITEM 4. CONTROLS AND PROCEDURES.

Disclosure Controls and Procedures

We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Exchange Act. Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of September 30, 2015 at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended September 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

In December 2014, we completed the acquisition of certain oil and gas assets from Chesapeake Energy Corporation in West Virginia and southwest Pennsylvania ("Chesapeake Property Acquisition"). Management continues to integrate the Chesapeake Property Acquisitions' internal controls over financial reporting with our internal controls over financial reporting. This integration may lead to changes in our controls in future fiscal periods, but management does not expect these changes to materially affect our internal control over financial reporting. Management will complete the integration process during 2015.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS.

Refer to “Litigation” in Note 10 to the unaudited condensed consolidated financial statements included in Item 1 of Part I of this Quarterly Report for a discussion of the Company’s legal proceedings.

ITEM 1A. RISK FACTORS.

There were no additions or material changes to our risk factors as disclosed in Item 1A of Part I in the Company’s 2014 Annual Report.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES.

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURES.

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

ITEM 5. OTHER INFORMATION.

Not applicable.

ITEM 6. EXHIBITS.

(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.

Signatures

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY
Registrant

Dated: October 22, 2015

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