WPX ENERGY, INC.
Form 10-Q
November 03, 2016

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)
þ QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number 1-35322
WPX Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

Delaware	45-1836028
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
3500 One Williams Center, Tulsa, Oklahoma	74172-0172
(Address of Principal Executive Offices)	(Zip Code)

855-979-2012
(Registrant's Telephone Number, Including Area Code)
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange
6.25% Series A Mandatory Convertible Preferred Stock, $0.01 par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None
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 þ 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 þ 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. (Check one):

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No þ
The number of shares outstanding of the registrant's common stock at November 2, 2016 were 344,461,810.

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Certain matters contained in this report include forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters.

All statements, other than statements of historical facts, included in this report that address activities, events or developments that we expect, believe or anticipate will exist or may occur in the future, are forward-looking statements. Forward-looking statements can be identified by various forms of words such as "anticipates," "believes," "seeks," "could," "may," "should," "continues," "estimates," "expects," "forecasts," "intends," "might," "goals," "objectives," "potential," "projects," "scheduled," "will" or other similar expressions. These forward-looking statements are based on management's beliefs and assumptions and on information currently available to management and include, among others, statements regarding:

- amounts and nature of future capital expenditures;
- crude oil, natural gas and NGL prices and demand;
- expansion and growth of our business and operations;
- financial condition and liquidity;
- business strategy;
- estimates of proved oil and natural gas reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations or results of operations;
- acquisitions or divestitures; and

- seasonality of our business.

Forward-looking statements are based on numerous assumptions, uncertainties and risks that could cause future events or results to be materially different from those stated or implied in this report. Many of the factors that will determine these results are beyond our ability to control or predict. Specific factors that could cause actual results to differ from results contemplated by the forward-looking statements include, among others, the following:

- availability of supplies (including the uncertainties inherent in assessing, estimating, acquiring and developing future oil and natural gas reserves), market demand, volatility of prices and the availability and cost of capital;
- inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- the strength and financial resources of our competitors;
- development of alternative energy sources;
- the impact of operational and development hazards;
- costs of, changes in, or the results of laws, government regulations (including climate change regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;
- changes in maintenance and construction costs;
- changes in the current geopolitical situation;
- our exposure to the credit risk of our customers;
- risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- risks associated with future weather conditions;
- acts of terrorism;
- other factors described in “Management’s Discussion and Analysis of Financial Condition and Results of Operations”; and
- additional risks described in our filings with the Securities and Exchange Commission (“SEC”).

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements set forth above. Given the uncertainties and risk factors that could cause our actual results to differ materially from those contained in any forward-looking statement, we caution investors not to unduly rely on our forward-looking statements. Forward-looking statements speak only as of the date they are made. We disclaim any obligation to and do not intend to update the above list or to announce publicly the result of any revisions to any of the forward-looking statements to reflect future events or developments, except to the extent required by applicable laws. If we update one or more forward-looking statements, no inference should be drawn that we will make additional updates with respect to those or other forward-looking statements.

In addition to causing our actual results to differ, the factors listed above and referred to below may cause our intentions to change from those statements of intention set forth in this report. Such changes in our intentions may also cause our results to differ. We may change our intentions, at any time and without notice, based upon changes in such factors, our assumptions or otherwise.

Because forward-looking statements involve risks and uncertainties, we caution that there are important factors, in addition to those listed above, that may cause actual results to differ materially from those contained in the forward-looking statements. For a detailed discussion of those factors, see Part II, Item 1A. Risk Factors in this filing and Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2015.

WPX Energy, Inc.
Consolidated Balance Sheets
(Unaudited)

	September 30, 2016	December 31, 2015
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$623	$ 38
Accounts receivable, net of allowance of $5 million as of September 30, 2016 and $6 million as of December 31, 2015	147	300
Derivative assets	79	308
Inventories	33	46
Assets classified as held for sale	7	178
Other	20	23
Total current assets	909	893
Properties and equipment (successful efforts method of accounting)	8,796	8,415
Less—accumulated depreciation, depletion and amortization	(2,314)	(1,893)
Properties and equipment, net	6,482	6,522
Derivative assets	31	51
Assets classified as held for sale	—	894
Other noncurrent assets	24	33
Total assets	$7,446	$ 8,393
Liabilities and Equity		
Current liabilities:		
Accounts payable	$185	$ 278
Accrued and other current liabilities	259	301
Liabilities associated with assets held for sale	2	140
Current portion of long-term debt, net	125	1
Derivative liabilities	53	13
Total current liabilities	624	733
Deferred income taxes	323	465
Long-term debt, net	2,574	3,189
Derivative liabilities	44	2
Asset retirement obligations	105	99
Liabilities associated with assets held for sale	—	133
Other noncurrent liabilities	142	237
Contingent liabilities and commitments (Note 9)		
Equity:		
Stockholders’ equity:		
Preferred stock (100 million shares authorized at $0.01 par value; 4.8 million shares issued at September 30, 2016 and 7 million shares issued at December 31, 2015)	232	339
Common stock (2 billion shares authorized at $0.01 par value; 344.5 million shares issued at September 30, 2016 and 275.4 million shares issued at December 31, 2015)	3	3
Additional paid-in-capital	6,799	6,164
Accumulated deficit	(3,400)	(2,971)
Total stockholders’ equity	3,634	3,535
Total liabilities and equity	$7,446	$ 8,393

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Operations
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Revenues:	(Millions, except per-share amounts)			
Product revenues:				
Oil sales	$139	$120	$378	$370
Natural gas sales	37	37	86	104
Natural gas liquid sales	12	6	27	14
Total product revenues	188	163	491	488
Gas management	25	35	172	248
Net gain (loss) on derivatives (Note 12)	38	205	(59)	239
Other	—	4	1	6
Total revenues	251	407	605	981
Costs and expenses:				
Lease and facility operating	40	34	123	101
Gathering, processing and transportation	19	17	55	50
Taxes other than income	14	14	41	45
Gas management, including charges for unutilized pipeline capacity	31	43	202	210
Exploration (Note 5)	10	56	31	69
Depreciation, depletion and amortization	150	136	465	376
Net (gain) loss on sales of assets and divestment of transportation contracts (Note 5)	227	(2)	25	(279)
General and administrative (including non-cash equity-based compensation of $10 million, $7 million, $25 million and $24 million for the respective periods)	51	45	159	152
Acquisition costs (Note 2)	—	23	—	23
Other—net	10	8	14	33
Total costs and expenses	552	374	1,115	780
Operating income (loss)	(301)	33	(510)	201
Interest expense	(49)	(65)	(159)	(130)
Loss on extinguishment of acquired debt	—	(65)	—	(65)
Investment income and other	—	—	1	2
Income (loss) from continuing operations before income taxes	(350)	(97)	(668)	8
Provision (benefit) for income taxes (Note 8)	(132)	(27)	(227)	3
Income (loss) from continuing operations	(218)	(70)	(441)	5
Income (loss) from discontinued operations	(1)	(160)	12	(197)
Net income (loss)	(219)	(230)	(429)	(192)
Less: Net income (loss) attributable to noncontrolling interests	—	—	—	1
Comprehensive income (loss) attributable to WPX Energy, Inc.	(219)	(230)	(429)	(193)
Less: Dividends on preferred stock	4	4	15	4
Less: Loss on induced conversion of preferred stock	22	—	22	—
Net income (loss) attributable to WPX Energy, Inc. common stockholders	$(245)	$(234)	$(466)	$(197)
Amounts attributable to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	$(244)	$(74)	$(478)	$1
Income (loss) from discontinued operations	(1)	(160)	12	(198)
Net income (loss)	$(245)	$(234)	$(466)	$(197)
Basic earnings (loss) per common share (Note 4):				

Income (loss) from continuing operations	$(0.72)	$(0.29)	$(1.58)	$0.01
Income (loss) from discontinued operations	—	(0.64)	0.04	(0.90)
Net income (loss)	$(0.72)	$(0.93)	$(1.54)	$(0.89)
Basic weighted-average shares	341.5	251.2	302.8	220.3
Diluted earnings (loss) per common share (Note 4):				
Income (loss) from continuing operations	$(0.72)	$(0.29)	$(1.58)	$0.01
Income (loss) from discontinued operations	—	(0.64)	0.04	(0.90)
Net income (loss)	$(0.72)	$(0.93)	$(1.54)	$(0.89)
Diluted weighted-average shares	341.5	251.2	302.8	221.7

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Changes in Equity
(Unaudited)

	WPX Energy, Inc., Stockholders				
	Preferred Stock	Common Stock	Additional Paid-In-Capital	Accumulated Deficit	Total Stockholders' Equity
Balance at December 31, 2015	$339	$3	$ 6,164	$ (2,971)	$ 3,535
Comprehensive income (loss) attributable to WPX Energy, Inc.	—	—	—	(429)	(429)
Stock based compensation	—	—	16	—	16
Issuance of common stock to public, net of offering costs	—	—	538	—	538
Conversion of preferred stock to common stock	(107)	—	118	—	11
Loss on induced conversion of preferred stock and related conversion costs	—	—	(22)	—	(22)
Dividends on preferred stock	—	—	(15)	—	(15)
Balance at September 30, 2016	$232	$3	$ 6,799	$ (3,400)	$ 3,634

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Cash Flows
(Unaudited)

	Nine months ended September 30,	
	2016	2015
Operating Activities(a)	(Millions)	
Net income (loss)	$(429)	$(192)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	474	685
Deferred income tax provision (benefit)	(209)	(138)
Provision for impairment of properties and equipment (including certain exploration expenses)	29	78
Net (gain) loss on derivatives in continuing operations	59	(239)
Net settlements related to derivatives in continuing operations	260	422
Net loss on derivatives included in discontinued operations	46	—
Amortization of stock-based awards	27	27
Gain on extinguishment of debt	—	81
Net (gain) loss on sales of assets and divestment of transportation contracts	(28)	(317)
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	147	232
Inventories	13	(11)
Margin deposits and customer margin deposits payable	—	25
Other current assets	6	—
Accounts payable	(79)	(186)
Federal income taxes payable	(33)	—
Accrued and other current liabilities	(97)	22
Accrued liabilities established in 2015 for retained transportation and gathering contracts related to discontinued operations	(42)	—
Other, including changes in other noncurrent assets and liabilities	(35)	140
Net cash provided by operating activities(a)	109	629
Investing Activities(a)		
Capital expenditures(b)	(440)	(890)
Proceeds from sales of assets	1,140	610
Proceeds (payments) related to divestment of transportation contracts	(238)	209
Purchases of business, net of cash acquired	—	(1,190)
Other	(2)	2
Net cash provided by (used in) investing activities(a)	460	(1,259)
Financing Activities		
Proceeds from common stock	540	295
Proceeds from preferred stock	—	339
Dividends paid on preferred stock	(15)	—
Payments related to induced conversion of preferred stock to common stock	(10)	—
Proceeds from long-term debt	—	1,000
Borrowings on credit facility	380	756
Payments on credit facility	(645)	(636)
Payments for retirement of debt	(230)	(1,055)
Payments for credit facility amendment fees, debt issuance cost and acquisition bridge financing fees	(3)	(40)
Other	(1)	—

Net cash provided by (used in) financing activities	16	659
Net increase (decrease) in cash and cash equivalents	585	29
Cash and cash equivalents at beginning of period	38	70
Cash and cash equivalents at end of period	$623	$99

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(a) Amounts reflect continuing and discontinued operations unless otherwise noted. See Note 3 of Notes to Consolidated Financial Statements for discussion of discontinued operations.

(b) Increase to properties and equipment	$(424)	$(640)
Changes in related accounts payable and accounts receivable	(16)	(250)
Capital expenditures	$(440)	$(890)

See accompanying notes.

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WPX Energy, Inc.
Notes to Consolidated Financial Statements
Note 1. Description of Business and Basis of Presentation
Description of Business
Operations of our company include oil, natural gas and NGL development, production, and gas management activities primarily located in Texas, North Dakota, New Mexico and Colorado. We specialize in development and production from tight-sands and shale formations in the Delaware, Williston and San Juan Basins. We also have operations and interests in the Appalachian and Green River Basins located in Pennsylvania and Wyoming. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts, such as transportation and related derivatives, and the marketing of Piceance Basin volumes during a transition period which ended June 30, 2016 (see Note 3).
In addition, we had other operations sold in 2015 and 2016 reported as discontinued operations, as discussed below.
The consolidated businesses represented herein as WPX Energy, Inc. is also referred to as “WPX,” the “Company,” “we,” “us” or “our.”
Basis of Presentation
The accompanying interim consolidated financial statements do not include all the notes included in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto for the year ended December 31, 2015 in Exhibit 99.1 of our Form 8-K filed on May 25, 2016. The accompanying interim consolidated financial statements include all normal recurring adjustments that, in the opinion of management, are necessary to present fairly our financial position at September 30, 2016, results of operations for the three and nine months ended September 30, 2016 and 2015, changes in equity for the nine months ended September 30, 2016 and cash flows for the nine months ended September 30, 2016 and 2015.
The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.
Our continuing operations comprise a single business segment, which includes the development, production and gas management activities of oil, natural gas and NGLs in the United States.
Discontinued Operations
On February 8, 2016, we signed an agreement to sell our Piceance Basin operations in Colorado to Terra Energy Partners LLC (“Terra”) for $910 million. This transaction closed on April 8, 2016 and we received net proceeds of $862 million. The results of operations of the Piceance Basin have been reported as discontinued operations on the Consolidated Statements of Operations (see Note 3). In addition, discontinued operations include the results of our Powder River Basin operations in Wyoming which were sold on September 1, 2015. Discontinued operations also include our 69 percent controlling interest in Apco Oil and Gas International Inc. (“Apco”), an oil and gas exploration and production company with activities in Argentina and Colombia which was sold on January 29, 2015.
See Note 3 for a further discussion of discontinued operations. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations. Additionally, see Note 9 for a discussion of contingencies related to the former power business of The Williams Companies, Inc. (“Williams”) (most of which was disposed of in 2007).
Recently Issued Accounting Standards
In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2014-09, Revenue from Contracts with Customers, and has updated with additional ASUs. The core principles of the guidance in ASU 2014-09 are that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09, as amended, is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. ASU 2014-09 can be applied using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. The Company is currently evaluating the method of adoption and the impact, if any, of ASU 2014-09 to the Company's Consolidated Financial Statements or related disclosures.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

In August 2014, the FASB issued ASU 2014-15, Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern, to provide guidance on management’s responsibility in evaluating whether there is substantial doubt about a company’s ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. The Company does not expect the adoption of ASU 2014-15 to have a significant impact on the Company’s Consolidated Financial Statements or related disclosures.

In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities, enhancing the reporting model for financial instruments. The amendments in ASU 2016-01 address certain aspects of recognition, measurement, presentation, and disclosure of financial instruments. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is only permitted under specific circumstances. The Company is currently evaluating the impact, if any, of ASU 2016-01 to the Company's Consolidated Financial Statements or related disclosures.

In February 2016, the FASB issued ASU 2016-02, Leases, to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted for any entity in any interim or annual period. The Company is currently evaluating the impact of ASU 2016-02 to the Company's Consolidated Financial Statements or related disclosures.

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting, as part of the Simplification Initiative. The areas for simplification in ASU 2016-09 involve several aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. ASU 2016-09 is effective for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Early adoption is permitted for any entity in any interim or annual period. The Company is currently evaluating the impact, if any, of ASU 2016-09 to the Company's Consolidated Financial Statements or related disclosures.

In August 2016, the FASB issued ASU 2016-15, Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments, which provides new guidance for eight specific cash flow issues. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is permitted. The Company does not expect the adoption of ASU 2016-15 to have a significant impact on the Company’s Consolidated Statements of Cash Flows.

Note 2. Acquisition

On August 17, 2015, we completed the acquisition of privately held RKI Exploration & Production, LLC (“RKI”) (the “Acquisition”). The Acquisition qualified as a business combination and, as a result, we estimated the fair value of the underlying shares distributed, the assets acquired and the liabilities assumed as of the August 17, 2015 acquisition date as disclosed in Exhibit 99.1 of our Form 8-K filed on May 25, 2016. We adjusted the purchase price allocation resulting in an increase of $60 million to both properties and equipment and deferred taxes in the third quarter of 2016.

The following table presents the unaudited pro forma financial results for the three and nine months ended September 30, 2015 as if the Acquisition and related financings had been completed January 1, 2015. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the Acquisition occurred on the date assumed or for the period presented, nor is such information indicative of the Company’s expected future results of operations.

	Three months ended September 30, 2015	Nine months ended September 30, 2015

	(Millions)	
Revenues	$504	$ 1,193
Net income from continuing operations attributable to WPX Energy, Inc.	$40	$ 90

Note 3. Discontinued Operations

On February 8, 2016, we signed an agreement with Terra to sell WPX Energy Rocky Mountain, LLC that holds our Piceance Basin operations for $910 million. The agreement also required Terra to become financially responsible for approximately $104 million in transportation obligations held by our marketing company. Additionally, WPX Energy Rocky

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Mountain, LLC had natural gas derivatives with a fair value of $48 million as of the closing date. The parties closed this sale in April of 2016 and we received net proceeds of $862 million, subject to post-closing adjustments, resulting in a gain of $53 million. We performed certain transition services for the buyer which concluded during third-quarter 2016. In addition, we had an agreement with the buyer to purchase production through June 30, 2016 which is reported in gas management revenue and expenses. The Piceance Basin operations are included in our domestic results presented below.

In August 2015, we signed agreements for the sale of our Powder River Basin for $80 million. On September 1, 2015, we completed a portion of the Powder River Basin divestiture. The remaining portion of the divestiture, which related to an equity method investment in Fort Union Gas Gathering, LLC, closed on October 30, 2015. We recorded a pre-tax loss of $15 million related to this divestment during third quarter 2015. During the first and second quarters of 2015, we recorded a total of $16 million in impairments of the net assets to a probability weighted-average of expected sales prices for the Powder River Basin. In addition, we retained certain firm gathering and treating obligations with total commitments of $104 million through 2020 related to the Powder River properties sold. These commitments had been in excess of our production throughput. At the time of closing, we also had certain pipeline capacity obligations held by our marketing company with total commitments through 2021 totaling $150 million, which were related to the Powder River operations. With the closing of the Powder River Basin sale and exiting this basin, we recorded $187 million of expense related to these contracts, which is included as a separate line below. This $187 million expense is the estimated present value of the $254 million in payments associated with these contracts remaining as of the Powder River Basin sales date, and includes the fair value of estimated recoveries from third parties and discounting based on our risk adjusted borrowing rate. During third quarter 2015, we received $13 million in escrow funds as a result of terminating a previous sales contract for the Powder River Basin assets and this amount is included in Other-net expense below. The Powder River Basin operations are included in our domestic results presented below.

On January 29, 2015, we completed the divestiture of our international interests and received net proceeds of $291 million after expenses but before $17 million of cash on hand at Apco as of the closing date. These non-operated international holdings comprised our international segment. We recorded a pretax gain of $41 million related to this transaction during first quarter 2015.

Summarized Results of Discontinued Operations

	Three months ended September 30, 2016	Three months ended September 30, 2015
	Domestic and Total	Domestic and Total
	(Millions)	
Total revenues	$—	$ 142
Costs and expenses:		
Lease and facility operating	$—	$ 22
Gathering, processing and transportation	1	68
Taxes other than income	1	4
Depreciation, depletion and amortization	—	106
General and administrative	1	13
Accrual for contract obligations retained	—	187
Other—net	(2)	(14)
Total costs and expenses	1	386

Operating income (loss)	(1)	(244)
Investment income and other	—	3
Gain (loss) on sale of domestic assets	1	(15)
Income (loss) from discontinued operations before income taxes	—	(256)
Provision (benefit) for income taxes	1	(96)
Income (loss) from discontinued operations	$(1)	$ (160)

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

	Nine months ended September 30, 2016	Nine months ended September 30, 2015		
	Domestic and Total	Domestic	International	Total
	(Millions)			
Total revenues(a)	$64	$466	$ 15	$481
Costs and expenses:				
Lease and facility operating	$18	$80	$ 4	$84
Gathering, processing and transportation	49	205	—	205
Taxes other than income	2	18	3	21
Gas management	—	1	—	1
Depreciation, depletion and amortization	9	309	—	309
Impairment of assets held for sale	—	16	—	16
General and administrative	9	34	1	35
Accrual for contract obligations retained	—	187	—	187
Other—net	4	(9)	—	(9)
Total costs and expenses	91	841	8	849
Operating income (loss)	(27)	(375)	7	(368)
Investment income and other	—	6	1	7
Gain (loss) on sale of domestic assets and international interests	53	(15)	41	26
Income (loss) from discontinued operations before income taxes	26	(384)	49	(335)
Provision (benefit) for income taxes(b)	14	(135)	(3)	(138)
Income (loss) from discontinued operations	$12	$(249)	$ 52	$(197)

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(a) The nine months ended September 30, 2016 includes $33 million net loss on derivatives.
(b) The nine months ended September 30, 2016 includes a valuation allowance on certain state tax carryovers. International for the nine months ended September 30, 2015 includes the reversal of certain U.S. deferred tax liabilities associated with Apco.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Assets and Liabilities in the Consolidated Balance Sheets attributable to Discontinued Operations

The assets held for sale and liabilities associated with assets held for sale on the Consolidated Balance Sheet as of September 30, 2016 relate to certain assets and liabilities in the Appalachia Basin. The operations of the Appalachia Basin are reported in continuing operations. As of December 31, 2015, the following table presents domestic assets classified as held for sale and liabilities associated with assets held for sale related to our Piceance Basin operations.

	December 31, 2015 Total
Assets classified as held for sale	
Current assets:	
Accounts receivable (including an affiliate receivable)	$ 55
Derivative assets	68
Inventories	13
Other	2
Total current assets	138
Properties and equipment, net(a)	880
Derivative assets	14
Total assets classified as held for sale—discontinued operations	$ 1,032
Total assets classified as held for sale—continuing operations (Note 5)	40
Total assets classified as held for sale on the Consolidated Balance Sheets	$ 1,072
Liabilities associated with assets held for sale	
Current liabilities:	
Accounts payable	$ 93
Accrued and other current liabilities	47
Total current liabilities	140
Asset retirement obligations	133
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	$ 273

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(a) Includes $2,308 million impairment in Piceance Basin of the net assets.

Cash Flows Attributable to Discontinued Operations

Excluding income taxes and changes to working capital, total cash provided by domestic operating activities was $28 million and used by domestic operating activities was $59 million for the nine months ended September 30, 2016 and 2015, respectively. In addition, cash outflows related to previous accruals for the Powder River Basin gathering and transportation contracts retained by WPX were $42 million for the nine months ended September 30, 2016. Cash provided by operating activities related to our international operations was $3 million for the nine months ended September 30, 2015. Total cash used in investing activities related to domestic discontinued operations was $32 million and $219 million for the nine months ended September 30, 2016 and 2015, respectively. Total cash used in investing activities related to our international operations was $15 million for the nine months ended September 30, 2015.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Note 4. Earnings (Loss) Per Common Share from Continuing Operations
The following table summarizes the calculation of earnings per share.

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(Millions, except per-share amounts)			
Income (loss) from continuing operations attributable to WPX Energy, Inc.	$(218)	$(70)	$(441)	$5
Less: Dividends on preferred stock	4	4	15	4
Less: Loss on induced conversion of preferred stock	22	—	22	—
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$(244)	$(74)	$(478)	$1
Basic weighted-average shares	341.5	251.2	302.8	220.3
Effect of dilutive securities(a):				
Nonvested restricted stock units and awards	—	—	—	1.3
Stock options	—	—	—	0.1
Diluted weighted-average shares	341.5	251.2	302.8	221.7
Earnings (loss) per common share from continuing operations:				
Basic	$(0.72)	$(0.29)	$(1.58)	$0.01
Diluted	$(0.72)	$(0.29)	$(1.58)	$0.01

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(a) The following table includes amounts that have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive due to our loss from continuing operations attributable to WPX Energy, Inc. available to common stockholders.

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(Millions)			
Weighted-average nonvested restricted stock units and awards	2.4	0.7	1.8	—
Weighted-average stock options	—	0.1	—	—
Common shares issuable upon assumed conversion of 6.25% Series A mandatory convertible preferred stock (Note 10)	23.8	26.7	23.8	9.0

The table below includes information related to stock options that were outstanding at September 30, 2016 and 2015 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the third quarter weighted-average market price of our common shares.

	September 30,	
	2016	2015
Options excluded (millions)	2.4	2.6
Weighted-average exercise price of options excluded	$16.46	$16.16
Exercise price range of options excluded	$11.75 - $21.81	$11.46 - $21.81
Third quarter weighted-average market price	$11.11	$8.36

For the nine months ended September 30, 2016 and 2015, approximately 0.1 million and 1.1 million, respectively, nonvested restricted stock units were antidilutive and were excluded from the computation of diluted weighted-average shares.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Note 5. Asset Sales, Other Expenses and Exploration Expenses
Asset Sales and Divestment of Transportation Contracts
During July 2016, we completed the divestment of the remaining transportation contracts primarily related to our Piceance Basin operations which eliminated certain pipeline capacity obligations held by our marketing company, which were not included in the Piceance Basin divestment to Terra. The total remaining commitments related to these contracts for the remainder of 2016 and thereafter were approximately $400 million. As a result of the divestments and net payment of $238 million, we recorded a net loss of $238 million in third-quarter 2016.
On March 9, 2016, we completed the sale of our San Juan Basin gathering system for consideration of approximately $309 million to a portfolio company of ISQ Global Infrastructure Fund, a fund managed by I Squared Capital. The consideration reflects $285 million in cash, subject to closing adjustments, and a commitment estimated at $24 million in capital designated by the purchaser to expand the system to support WPX's development in the Gallup oil play. We are obligated to complete certain in-progress construction as of the closing which resulted in the deferral of a portion of the gain. Under the terms of the agreement, WPX will continue to operate, at the direction of the owner, the gathering system for an initial term of two years with the opportunity to continue in ensuing years. The gathering system consists of more than 220 miles of oil, gas and water gathering lines that WPX installed in conjunction with drilling in the Gallup oil play where it made a discovery in 2013. As a result of this transaction, we recorded a gain of $199 million in first-quarter 2016 and additional gains of $5 million and $11 million in the second and third quarters of 2016, respectively, as certain in-progress construction was completed. As of September 30, 2016, the deferred gain was $14 million related to an estimated $4 million of remaining recorded obligations for in-progress construction.
During May 2015, WPX completed the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast for approximately $209 million in cash. The transaction released WPX from various long-term natural gas purchase and sales obligations and future demand payment obligations associated with the transport position. As a result of this transaction, we recorded a net gain of $209 million in second-quarter 2015 on these executory contracts.
During the first quarter of 2015, we sold a portion of our Appalachian Basin operations and released certain firm transportation capacity to Southwestern Energy Company (NYSE: SWN) for approximately $288 million, before post-closing adjustments. Including an estimate of post-closing adjustments of $17 million, we recorded a net gain of $69 million in first-quarter 2015.
Other Expenses
During the first quarter of 2015, we executed a termination and settlement agreement to release us from a crude oil transportation and sales agreement in anticipation of entering into a different agreement with another third party with more favorable terms. As a result of this contract termination and settlement, we recorded an expense of approximately $22 million which is included in Other—net on the Consolidated Statements of Operations.
Exploration Expenses
The following table presents a summary of exploration expenses.

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(Millions)			
Geologic and geophysical costs	$ 1	$ 3	$ 2	$ 5
Dry hole costs and impairments of exploratory area well costs	—	22	1	22
Unproved leasehold property impairment, amortization and expiration	9	31	28	42
Total exploration expenses	$ 10	$ 56	$ 31	$ 69

For both the three and nine months ended September 30, 2015, dry hole costs and impairments of exploratory area well costs and unproved leasehold property impairment, amortization and expiration include $21 million and $26 million, respectively, related to a non-core exploratory play where we no longer intend to continue exploration activities.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Note 6. Inventories
The following table presents a summary of our inventories as of the dates indicated below.

	September 30, 2016	December 31, 2015
	(Millions)	
Material, supplies and other	$ 31	$ 44
Crude oil production in transit	2	2
Total inventories	$ 33	$ 46

During the third quarter of 2016, we recorded an impairment of material and supplies inventory of approximately $4 million.
Note 7. Debt and Banking Arrangements
The following table presents a summary of our debt as of the dates indicated below.

	September 30, 2016	December 31, 2015
	(Millions)	
5.250% Senior Notes due 2017	$125	$ 355
7.500% Senior Notes due 2020	500	500
6.000% Senior Notes due 2022	1,100	1,100
8.250% Senior Notes due 2023	500	500
5.250% Senior Notes due 2024	500	500
Credit facility agreement	—	265
Other	1	1
Total debt	$2,726	$ 3,221
Less: Current portion of long-term debt, net(a)	125	1
Total long-term debt	$2,601	$ 3,220
Less: Debt issuance costs on long-term debt(b)	27	31
Total long-term debt, net(b)	$2,574	$ 3,189

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(a) Includes debt issuance costs.
(b) Debt issuance costs related to our Credit Facility are recorded in other noncurrent assets on the Consolidated Balance Sheets.

Senior Notes
During 2016, we repurchased approximately $230 million of our 5.250% Senior Notes due 2017, including $87 million we redeemed through a tender offer.
See Exhibit 99.1 of our Form 8-K filed on May 25, 2016 which includes the financial statements and footnotes for the year ended December 31, 2015 for a discussion of our previously issued senior notes.
Credit Facility
On March 18, 2016, the Company entered into a Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the “Credit Facility”). The Credit Facility, as amended, is now a $1.2 billion senior secured revolving credit facility with a maturity date of October 28, 2019. The Credit Facility may be used for working capital, acquisitions, capital expenditures and other general corporate purposes. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of September 30, 2016, we were in compliance with our financial covenants and had full access to the Credit Facility subject to the Borrowing Base discussed below.

During any Collateral Trigger Period, loans under the Credit Facility will be subject to a Borrowing Base as calculated in accordance with the provisions of the Credit Facility. As of March 18, 2016, the Borrowing Base was set at $1.025 billion. The Borrowing Base was reaffirmed at $1.025 billion in October 2016. This Borrowing Base will remain in effect until the next

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Borrowing Base is re-determined pursuant to the Credit Facility. The next Scheduled Re-determination Date is April 1, 2017 and biannually thereafter.

Subject to the satisfaction of certain conditions set forth in the Credit Facility, during any Collateral Trigger Period (as described below), the Company may designate Loans under the Credit Facility as either General Loans, the proceeds of which may be used for the general purposes described above, or as Development Loans, the proceeds of which shall be used solely for the development of oil and gas property owned or leased by the Company and certain of its subsidiaries. Additionally, during any Collateral Trigger Period, the Loans shall be secured and the obligations outstanding under the Credit Facility shall be guaranteed, in each case, as more particularly described below.

On the date of the closing of the Credit Facility a Collateral Trigger Period shall be in effect and all Loans outstanding shall be deemed to be General Loans. The General Loans and the other General Secured Obligations outstanding under the Credit Facility will initially be guaranteed by certain subsidiaries of the Company (excluding subsidiaries holding Midstream Assets and subsidiaries meeting other customary exclusion criteria), as Guarantors, and secured by substantially all of the Company’s and the Guarantors’ assets (including oil and gas properties), subject to customary exceptions and carve outs (which shall also exclude Midstream Assets and the equity interests of subsidiaries holding Midstream Assets). Any Development Loans and any Development Secured Obligations shall be secured by certain oil, gas or other mineral properties developed with the proceeds thereof and not otherwise securing the General Secured Obligations. Such obligations will continue to be secured during any Collateral Trigger Period and such security interest shall terminate on the earlier of any applicable Collateral Trigger Termination Date (as described below) or the date on which all liens held by the Administrative Agent for the benefit of the secured parties are released pursuant to the terms of the Credit Facility.

The Collateral Trigger Period means, as applicable, (1) the period beginning on the date of the closing of the Credit Facility, as amended, and ending on the initial Collateral Trigger Termination Date and (2) each period beginning on a Collateral Trigger Date (as described below) and ending on the first Collateral Trigger Termination Date occurring after such Collateral Trigger Date.

The Collateral Trigger Date is the first date after any Collateral Trigger Termination Date on which either (1) the Company’s Corporate Rating is Ba3 or lower (or unrated) by Moody’s or BB- or lower (or unrated) by S&P or (2) the Company elects to have the Borrowing Base apply. The Collateral Trigger Termination Date is the first date following the date of the closing of the Credit Facility and the first date following any Collateral Trigger Date, as applicable, on which (1)(i) the Company’s Corporate Rating is BBB- or better by S&P (without negative outlook or negative watch) or (ii) Baa3 or better by Moody’s (without negative outlook or negative watch), provided that the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody’s or (2) both (i) the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) is less than or equal to 3.00 to 1.00 and (ii) the Corporate Rating is (A) at least Ba1 by Moody’s and at least BB by S&P or (B) at least Ba2 by Moody’s and at least BB+ by S&P. If the Company elects to have the Borrowing Base apply, the Collateral Trigger Termination Date is the date the Company elects under the terms of the Credit Facility to no longer have the Borrowing Base apply.

Interest on borrowings under the Credit Facility is payable at rates per annum equal to, at the Company’s option: (1) a fluctuating base rate equal to the alternate base rate plus the applicable margin, or (2) a periodic fixed rate equal to LIBOR plus the applicable margin. The alternate base rate will be the highest of (i) the federal funds rate plus 0.5 percent, (ii) the Prime Rate, and (iii) one-month LIBOR plus 1.0 percent. The Company is required to pay a commitment fee based on the unused portion of the commitments under the Credit Facility. The applicable margin and the commitment fees during a Collateral Trigger Period are determined by reference to a utilization percentage as set forth in the Credit Facility. The applicable margin and the commitment fee other than during a Collateral Trigger Period are determined by reference to a pricing schedule based on the Company’s senior unsecured non-credit enhanced debt ratings.

During any Collateral Trigger Period, the Company is required to maintain a ratio of Consolidated Secured Indebtedness to Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) of not greater than 3.25 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2017 and 3.00 to 1.00

thereafter. During any Collateral Trigger Period, the Company may also not permit the ratio of consolidated current assets (including the unused amount of the Borrowing Base) of the Company and its consolidated subsidiaries to the consolidated current liabilities of the Company and its consolidated subsidiaries as of the last day of any fiscal quarter to be less than 1.0 to 1.0.

Other than during a Collateral Trigger Period, the Company is required to maintain a ratio of Consolidated Net Indebtedness to Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) of not greater than 4.50 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and 4.00 to 1.00 thereafter, unless at such time the Company’s Corporate Ratings are equal to, or better than, Baa3 or BBB- by at least one of S&P and Moody’s and not less than BB+ or Ba1 by the other such agency. In addition, other than during a Collateral Trigger Period, the ratio of Consolidated Indebtedness to Consolidated Total Capitalization is not permitted to be greater than 60 percent and is applicable

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

for the life of the agreement. Furthermore, other than during a Collateral Trigger Period, the Company may not permit the ratio of Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) to Consolidated Interest Charges to be less than 2.5 to 1.00.

The Credit Facility contains customary representations and warranties and affirmative, negative and financial covenants (as described above) which were made only for the purposes of the Credit Facility and as of the specific date (or dates) set forth therein, and may be subject to certain limitations as agreed upon by the contracting parties. The covenants limit, among other things, the ability of the Company's subsidiaries to incur indebtedness; the ability of the Company and its subsidiaries to grant certain liens, make restricted payments, materially change the nature of its or their business, make investments, guarantees, loans or advances in non-subsidiaries or enter into certain hedging agreements; the ability of the Company's material subsidiaries to enter into certain restrictive agreements; the ability of the Company and its material subsidiaries to enter into certain affiliate transactions; the ability of the Company and its subsidiaries to redeem any senior notes; and the Company's ability to merge or consolidate with any person or sell all or substantially all of its assets to any person. The Company and its subsidiaries are also prohibited from using the proceeds under the Credit Facility in violation of Sanctions (as defined in the Credit Facility). In addition, the representations, warranties and covenants contained in the Credit Facility are subject to certain exceptions and/or standards of materiality applicable to the contracting parties.

The Credit Facility includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross payment-defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments, a change of control and, during any secured period, the failure of the collateral documents to be in effect or a lien to be valid and perfected. If an event of default with respect to a borrower occurs under the Credit Facility, the lenders will be able to terminate the commitments and accelerate the maturity of the loans of the defaulting borrower under the Credit Facility and exercise other rights and remedies.

Letters of Credit

WPX has also entered into three bilateral, uncommitted letter of credit ("LC") agreements most of which expire during 2016. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility. As a result of the divestment of our Piceance Basin transportation contracts, we eliminated approximately $162 million in letters of credit and their associated annual interest expense. At September 30, 2016, a total of $66 million in letters of credit have been issued, a majority of which support interstate pipeline contracts. As these letter of credit agreements expire, we expect to issue letters of credit under our Credit Facility.

Note 8. Provision (Benefit) for Income Taxes

The following table presents the provision (benefit) for income taxes from continuing operations.

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(Millions)			
Current:				
Federal	$—	$(4)	$—	$(4)
State	(5)	(1)	(5)	(1)
	(5)	(5)	(5)	(5)
Deferred:				
Federal	(117)	(26)	(236)	7
State	(10)	4	14	1
	(127)	(22)	(222)	8
Total provision (benefit)	$(132)	$(27)	$(227)	$3

The effective income tax rate for the three months ended September 30, 2016, differs from the federal statutory rate due to the effects of state income taxes.

The effective income tax rate for the nine months ended September 30, 2016, differs from the federal statutory rate due to state tax adjustments resulting from the sale of our Piceance Basin operations in Colorado. In the first quarter of 2016, we recorded $8 million of valuation allowances against Colorado loss and credit carryovers generated in prior years. We also increased our state effective tax rate by less than a half percent in the first quarter of 2016 to reflect changes in our expected

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

future apportionment among the states where we continue to operate which resulted in a $14 million increase of our deferred tax liability as of the beginning of the year.

The effective income tax rate for the three months and nine months ended September 30, 2015, differs from the federal statutory rate due to the effects of state income taxes and certain nondeductible acquisition costs.

We have recorded valuation allowances against deferred tax assets attributable primarily to certain state net operating loss ("NOL") carryovers as well as our federal capital loss carryover. Valuation allowances that we have recorded are due to our expectation that we will not have sufficient income, or income of a sufficient character, in those jurisdictions to which the associated deferred tax asset applies. We have not recorded a valuation allowance against our federal NOL carryover, but a valuation allowance could be required in future periods if the federal NOL carryover continues to increase or circumstances change. When assessing the need for a valuation allowance for the federal NOL carryover we primarily consider future reversals of existing taxable temporary differences.

The ability of WPX to utilize loss carryovers or minimum tax credits to reduce future federal taxable income and income tax could be subject to limitations under the Internal Revenue Code. The utilization of such carryovers may be limited upon the occurrence of certain ownership changes during any three-year period resulting in an aggregate change of more than 50 percent in beneficial ownership (an "Ownership Change"). As of September 30, 2016, we do not believe that an Ownership Change has occurred for WPX, but a change could occur in the future due to shareholders with new positions in our stock greater than 5 percent. An Ownership Change did occur for RKI effective with the Acquisition which resulted in an annual limitation on the benefit that WPX can claim from RKI carryovers that arose prior to the Acquisition.

As of September 30, 2016, the amount of unrecognized tax benefits is not material. During the next 12 months we do not expect ultimate resolution of any uncertain tax position will result in a significant increase or decrease of our unrecognized tax benefit.

Pursuant to our tax sharing agreement with Williams, we remain responsible for the tax from audit adjustments related to our business for periods prior to our spin-off from Williams on December 31, 2011. The 2011 consolidated tax filing by Williams is currently being audited by the IRS and is the only pre spin-off period for which we continue to have exposure to audit adjustments as part of Williams. We are aware of an issue the IRS has questioned related to our business for which a payment to Williams could be required. We are currently evaluating the issue and the actions we might take should the IRS propose an adjustment. In addition, the alternative minimum tax credit deferred tax asset that was allocated to us by Williams at the time of the spin-off could change due to IRS audit adjustments unrelated to our business. Any such adjustment to this deferred tax asset will not be known until the IRS examination is completed but is not expected to result in a cash settlement.

Note 9. Contingent Liabilities and Commitments

Royalty litigation

In October 2011, a potential class of royalty interest owners in New Mexico and Colorado filed a complaint against us in the County of Rio Arriba, New Mexico. The complaint presently alleges failure to pay royalty on hydrocarbons including drip condensate, breach of the duty of good faith and fair dealing, fraudulent concealment, conversion, misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons in Colorado, breach of implied duty to market, violation of the New Mexico Oil and Gas Proceeds Payment Act, and bad faith breach of contract. Plaintiffs sought monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter was removed to the United States District Court for New Mexico where the court denied plaintiffs' motion for class certification. In August 2012, a second potential class action was filed against us in the United States District Court for the District of New Mexico by mineral interest owners in New Mexico and Colorado. Plaintiffs claim breach of contract, breach of the covenant of good faith and fair dealing, breach of implied duty to market both in Colorado and New Mexico and violation of the New Mexico Oil and Gas Proceeds Payment Act, and seek declaratory judgment, accounting and injunctive relief. On August 16, 2016, the court denied plaintiffs' motion for class certification. On September 15, 2016, plaintiffs filed their motion for reconsideration and filed a second motion for class certification. At this time, we believe that our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and applicable laws. We do not have sufficient information to calculate an estimated range of exposure related to these claims.

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we are monitoring them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue ("ONRR") in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The guidelines for New Mexico properties were revised slightly in September 2013 as a result of additional work performed by the ONRR. The revisions did not change the basic function of the original guidance. The ONRR's guidance provides its view as to how much of a producer's bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in Colorado though such guidelines are expected in the future. However, the timing of any such guidance is uncertain and, independent of the issuance of additional guidance, ONRR asked producers to attempt to evaluate the deductibility of these fees directly with the midstream companies that transport and process gas.

Environmental matters

The Environmental Protection Agency ("EPA"), other federal agencies, and various state and local regulatory agencies and jurisdictions routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, new air quality standards for ground level ozone, methane, green completions, and hydraulic fracturing and water standards. We are unable to estimate the costs of asset additions or modifications necessary to comply with these new regulations due to uncertainty created by the various legal challenges to these regulations and the need for further specific regulatory guidance.

Matter related to Williams' former power business

In connection with a Separation and Distribution Agreement between WPX and Williams, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us for the pending litigation described below relating to the reporting of certain natural gas-related information to trade publications.

Civil suits based on allegations of manipulating published gas price indices have been brought against us and others, seeking unspecified amounts of damages. We are currently a defendant in class action litigation and other litigation originally filed in state court in Colorado, Kansas, Missouri and Wisconsin and brought on behalf of direct and indirect purchasers of natural gas in those states. These cases were transferred to the federal court in Nevada. In 2008, the court granted summary judgment in the Colorado case in favor of us and most of the other defendants based on plaintiffs' lack of standing. On January 8, 2009, the court denied the plaintiffs' request for reconsideration of the Colorado dismissal and entered judgment in our favor.

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs' state law claims because the federal Natural Gas Act gives the Federal Energy Regulatory Commission exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs' class certification motion as moot. The plaintiffs appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion in the In re: Western States Wholesale Antitrust Litigation, holding that the Natural Gas Act does not preempt the plaintiffs' state antitrust claims and reversing the summary judgment previously entered in favor of the defendants. The U.S. Supreme Court granted Defendants' writ of certiorari. On April 21, 2015, the U.S. Supreme Court determined that the state antitrust claims are not preempted by the federal Natural Gas Act. On March 7, 2016, the putative class plaintiffs in several of the cases filed their motions for class certification. On May 24, 2016, in Reorganized FLI Inc. v. Williams Companies, Inc., the Court granted Defendants' Motion for Summary Judgment in its entirety. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposure at this time.

Other Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, including the agreement pursuant to which we divested our Piceance Basin operations, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breaches of representations and warranties, tax liabilities, historic litigation, personal injury, environmental matters and rights-of-way. The indemnity provided to the purchaser of the entity that held our Piceance Basin operations relates in substantial part to liabilities arising in connection with litigation over the appropriate calculation of royalty payments. Plaintiffs in that litigation have asserted claims regarding, among other things, the method by which we took transportation costs into account when calculating royalty payments.

At September 30, 2016, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss beyond any amount already accrued. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

In connection with the separation from Williams, we agreed to indemnify and hold Williams harmless from any losses resulting from the operation of our business or arising out of liabilities assumed by us. Similarly, Williams has agreed to indemnify and hold us harmless from any losses resulting from the operation of its business or arising out of liabilities assumed by it.

Summary

As of September 30, 2016 and December 31, 2015, the Company had accrued approximately $17 million for loss contingencies associated with royalty litigation and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, is not expected to have a materially adverse effect upon our future liquidity or financial position; however, it could be material to our results of operations in any given year.

Commitments

In conjunction with the sale of our San Juan Basin gathering system, our contractual obligations increased for gathering services to be provided by the purchaser over a ten year period. These obligations totaled approximately $363 million as of September 30, 2016.

As previously discussed in Note 5, we divested of transportation contracts in the third quarter of 2016 which eliminated certain pipeline capacity commitments for the remainder of 2016 and thereafter totaling approximately $400 million. As of December 31, 2015, our total commitments for pipeline capacity were approximately $686 million. Our total remaining commitments for pipeline capacity are approximately $128 million as of September 30, 2016 for which we previously accrued a liability in third-quarter 2015 in conjunction with the closing of the Powder River Basin sale and exiting the basin. The balance of this liability totaled approximately $99 million as of September 30, 2016 (see Note 3).

Note 10. Stockholders' Equity

On July 20, 2016, we entered into Conversion Agreements with certain existing beneficial owners (the "Preferred Holders") of our 6.25% Series A Mandatory Convertible Preferred Stock (the "Preferred Stock"), pursuant to which each of the Preferred Holders agreed to convert (the "Conversion") shares of Preferred Stock it beneficially owned into shares of our common stock, par value $0.01 per share, and in addition receive a cash payment from us in connection with the Conversion. The Preferred Holders agreed to convert an aggregate of 2,201,180 shares of Preferred Stock into 10,227,872 shares of our common stock in the Conversion, and we made an aggregate cash payment to the Preferred Holders of approximately $10 million. Following the Conversion, approximately 4.8 million shares of Preferred Stock remain outstanding. We issued the shares of common stock in the Conversion on July 28, 2016. As a result of the cash payment and additional shares issued as an inducement to the Preferred Holders, we recorded a loss of $22 million. The shares of common stock were issued in a transaction exempt from registration pursuant to Section 3(a)(9) of the Securities Act of 1933, as amended, as an exchange exclusively with existing security holders where no commission or other remuneration was paid or given directly or indirectly for soliciting such exchange. We retired the shares of Preferred Stock converted in the Conversion. By entering into the Conversion and associated transactions early, we reduced cash dividend payments and continued simplifying our capital and cost structure.

On June 6, 2016, we completed an underwritten public offering of 56.925 million shares of our common stock, which included 7.425 million shares of common stock issued pursuant to an option granted to the underwriters to purchase additional shares. The stock was sold to the underwriters at $9.47 per share and we received proceeds of approximately $538 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Note 11. Fair Value Measurements

The following table presents, by level within the fair value hierarchy, our assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the Consolidated Balance Sheets for cash and cash equivalents, restricted cash, and margin deposits and customer margin deposits payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	September 30, 2016				December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$—	$110	$ —	$110	$—	$359	$ —	$359
Energy derivative liabilities	$—	$97	$ —	$97	$—	$15	$ —	$15
Total debt(a)	$—	$2,752	$ —	$2,752	$—	$2,495	$ —	$2,495

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(a) The carrying value of total debt, excluding capital leases and debt issuance costs, was $2,725 million and $3,220 million as of September 30, 2016 and December 31, 2015, respectively. The fair value of our debt, which also excludes capital leases and debt issuance costs, is determined on market rates and the prices of similar securities with similar terms and credit ratings.

Energy derivatives include commodity based exchange-traded contracts and over-the-counter (“OTC”) contracts. Exchange-traded contracts include futures, swaps and options. OTC contracts include forwards, swaps, options and swaptions. These are carried at fair value on the Consolidated Balance Sheets.

Many contracts have bid and ask prices that can be observed in the market. Our policy is to use a mid-market pricing (the mid-point price between bid and ask prices) convention to value individual positions and then adjust on a portfolio level to a point within the bid and ask range that represents our best estimate of fair value. For offsetting positions by location, the mid-market price is used to measure both the long and short positions.

The determination of fair value for our assets and liabilities also incorporates the time value of money and various credit risk factors which can include the credit standing of the counterparties involved, master netting arrangements, the impact of credit enhancements (such as cash collateral posted and letters of credit) and our nonperformance risk on our liabilities. The determination of the fair value of our liabilities does not consider noncash collateral credit enhancements.

Exchange-traded contracts include New York Mercantile Exchange and Intercontinental Exchange contracts and are valued based on quoted prices in these active markets and are classified within Level 1.

Forward, swap, option and swaption contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars, calls or swaptions and are financially settled. All of our financial options are valued using an industry standard Black-Scholes option pricing model. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us. Significant inputs into our Level 2 valuations include commodity prices, implied volatility and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of over-the-counter products or like products and the tenure of our derivatives portfolio extends through the end of 2018. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes or market indications and documented on a quarterly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 were a net liability of less than $1 million at September 30, 2016, and consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers occurred during the periods ended September 30, 2016 and 2015. There have been no material changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Note 12. Derivatives and Concentration of Credit Risk

Energy Commodity Derivatives

Risk Management Activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of crude oil, natural gas and natural gas liquids attributable to commodity price risk.

We produce, buy and sell crude oil, natural gas and natural gas liquids at different locations throughout the United States. To reduce exposure to a decrease in revenues from fluctuations in commodity market prices, we enter into futures contracts, swap agreements and financial option contracts to mitigate the price risk on forecasted sales of crude oil, natural gas and natural gas liquids. We have also entered into basis swap agreements to reduce the locational price risk associated with our producing basins. Our financial option contracts are either purchased or sold options, or a combination of options that comprise a net purchased option, zero-cost collar or swaptions.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Derivatives related to production
The following table sets forth the derivative notional volumes of the net long (short) positions that are economic hedges of production volumes, which are included in our commodity derivatives portfolio as of September 30, 2016.

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)	Weighted Average Price (c)
Crude Oil					
Crude Oil	Oct -Dec 2016	Fixed Price Swaps	WTI	(30,403)	$ 60.13
Crude Oil	Oct -Dec 2016	Basis Swaps	Midland-Cushing	(5,000)	$ (0.45)
Crude Oil	Oct -Dec 2016	Fixed Price Calls	WTI	(1,900)	$ 50.70
Crude Oil	2017	Fixed Price Swaps	WTI	(29,554)	$ 51.31
Crude Oil	2017	Swaptions	WTI	(3,264)	$ 51.22
Crude Oil	2017	Fixed Price Calls	WTI	(4,500)	$ 56.47
Crude Oil	2018	Fixed Price Swaps	WTI	(13,000)	$ 58.33
Crude Oil	2018	Fixed Price Calls	WTI	(13,000)	$ 58.89
Natural Gas					
Natural Gas	Oct -Dec 2016	Fixed Price Swaps	Henry Hub	(146)	$ 3.93
Natural Gas	Oct -Dec 2016	Basis Swaps	Permian	(38)	$ (0.17)
Natural Gas	Oct -Dec 2016	Basis Swaps	San Juan	(100)	$ (0.18)
Natural Gas	2017	Fixed Price Swaps	Henry Hub	(150)	$ 2.98
Natural Gas	2017	Basis Swaps	Permian	(58)	$ (0.20)
Natural Gas	2017	Basis Swaps	San Juan	(93)	$ (0.17)
Natural Gas	2017	Fixed Price Calls	Henry Hub	(16)	$ 4.50
Natural Gas	2017	Swaptions	Henry Hub	(65)	$ 4.19
Natural Gas	2018	Fixed Price Swaps	Henry Hub	(40)	$ 2.91
Natural Gas	2018	Fixed Price Calls	Henry Hub	(16)	$ 4.75
Natural Gas	2018	Swaptions	Henry Hub	(20)	$ 3.33

Commodity	Period	Contract Type	Location(d)	Notional Volume (b)	Weighted Average Price
Physical Derivatives					
Natural Gas	Oct -Dec 2016	Index	Multiple	(65)	(e)
Natural Gas	2017	Index	Multiple	(16)	(e)

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(a) Derivatives related to crude oil production are fixed price swaps, basis swaps, fixed price calls and swaptions. The derivatives related to natural gas production are fixed price swaps, basis swaps, fixed price calls and swaptions. In connection with several crude oil and natural gas swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the crude oil and natural gas swaps. These swaptions grant the counterparty the option to enter into future swaps with us.
(b) Crude oil volumes are reported in Bbl/day and natural gas volumes are reported in BBtu/day.
(c) The weighted average price for crude oil is reported in \$/Bbl and natural gas is reported in \$/MMBtu.
(d) We transact at multiple locations primarily around our core assets to maximize the economic value of our transportation and asset management agreements.
(e) Weighted average price is not reported since the notional volumes represent a net position comprised of buys and sells with positive and negative transaction prices.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Fair values and gains (losses)

The following table presents the fair value of energy commodity derivatives. Our derivatives are presented as separate line items in our Consolidated Balance Sheets as current and noncurrent derivative assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivatives classified as current are expected to occur within the next 12 months. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of our master netting arrangements. Further, the amounts below do not include cash held on deposit in margin accounts that we have received or remitted to collateralize certain derivative positions.

	September 30, 2016		December 31, 2015	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Total derivatives	$110	$ 97	$359	$ 15

We enter into commodity derivative contracts that serve as economic hedges but are not designated as cash flow hedges for accounting purposes as we do not utilize this method of accounting for derivative instruments. The following table presents the net gain (loss) related to our energy commodity derivatives.

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(Millions)			
Gain (loss) from derivatives related to production(a)	$38	$206	$(59)	$260
Gain (loss) from derivatives related to physical marketing agreements(b)	—	(1)	—	(21)
Net gain (loss) on derivatives	$38	$205	$(59)	$239

(a) Includes settlements totaling $59 million and $159 million for the three months ended September 30, 2016 and 2015, respectively; and settlements totaling $260 million and $454 million for the nine months ended September 30, 2016 and 2015, respectively.

(b) Includes payments totaling $4 million and $32 million for the three months and nine months ended September 30, 2015, respectively.

The cash flow impact of our derivative activities is presented as separate line items within the operating activities on the Consolidated Statements of Cash Flows.

WPX Energy, Inc.
Notes to Consolidated Financial Statements — (Continued)

Offsetting of derivative assets and liabilities
The following table presents our gross and net derivative assets and liabilities.

	Gross Amount Presented on Balance Sheet	Netting Adjustments (a)	Net Amount
September 30, 2016	(Millions)		
Derivative assets with right of offset or master netting agreements	$ 110	$ (69)	$ 41
Derivative liabilities with right of offset or master netting agreements	$ (97)	$ 69	$ (28)
December 31, 2015			
Derivative assets with right of offset or master netting agreements	$ 359	$ (14)	$ 345
Derivative liabilities with right of offset or master netting agreements	$ (15)	$ 14	$ (1)

(a) With all of our financial trading counterparties, we have agreements in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements. Additionally, we have negotiated master netting agreements with some of our counterparties. These master netting agreements allow multiple entities that have multiple underlying agreements the ability to net derivative assets and derivative liabilities at settlement or in the event of a default or a termination under one or more of the underlying contracts.

Credit-risk-related features
Certain of our derivative contracts contain credit-risk-related provisions that would require us, under certain events, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor’s and/or Moody’s Investment Services. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability.

As of September 30, 2016, we had no collateral posted to derivative counterparties, to support the aggregate fair value of our $28 million net derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of $2 million to our liability balance for our own nonperformance risk. There would have been collateral totaling $30 million that we would have been required to post, assuming our credit thresholds were eliminated and a call for adequate assurance under the credit risk provisions in our derivative contracts was triggered at September 30, 2016.

Concentration of Credit Risk

Cash equivalents

Our cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Accounts receivable

Accounts receivable are carried on a gross basis, with no discounting, less the allowance for doubtful accounts. We estimate the allowance for doubtful accounts based on existing economic conditions, the financial conditions of the customers and the amount and age of past due accounts. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. A portion of our receivables are from joint interest owners of properties we operate. Thus, we may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors. Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by credit worthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2016 and 2015, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

The following table presents the gross and net credit exposure from our derivative contracts as of September 30, 2016.

Counterparty Type	Gross Total	Net Total
	(Millions)	
Financial institutions (Investment Grade)(a)	$110	$ 41
Credit exposure from derivatives	$110	$ 41

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(a) We determine investment grade primarily using publicly available credit ratings. We include counterparties with a minimum S&P's rating of BBB- or Moody's Investors Service rating of Baa3 in investment grade.

Our five largest net counterparty positions represent approximately 99 percent of our net credit exposure. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.

Other

Collateral support for our commodity agreements could include margin deposits, letters of credit, surety bonds and guarantees of payment by credit worthy parties.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The following discussion should be read in conjunction with the selected historical consolidated financial data and the consolidated financial statements and the related notes included elsewhere in this Form 10-Q and Exhibit 99.1 of our Form 8-K filed May 25, 2016. The matters discussed below may contain forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to these differences include, but are not limited to, those discussed below and elsewhere in this Form 10-Q and our 2015 Annual Report on Form 10-K.

On February 8, 2016, we signed an agreement to sell our Piceance Basin operations to Terra Energy Partners LLC ("Terra") and closed the transaction on April 8, 2016. The results of operations of the Piceance Basin are reported as discontinued operations (see Note 3 of Notes to Consolidated Financial Statements). In addition, our discontinued operations include the results of the Powder River Basin sold in September 2015 and our international interests sold in January 2015 (see Note 3 of Notes to Consolidated Financial Statements).

Unless indicated otherwise, the following discussion relates to continuing operations.

On August 17, 2015, we completed the acquisition of privately-held RKI Exploration & Production, LLC ("RKI"). See Note 2 of Notes to Consolidated Financial Statements for further discussion of the acquisition of RKI. The 2015 results of RKI after August 17, 2015 included in the following discussions include $22 million of product revenues, $12 million of depreciation, depletion and amortization and $7 million of lease operating expenses. In addition, we incurred $104 million of acquisition related expenses during the third quarter of 2015 including $23 million of legal and advisory fees, $16 million of bridge financing fees and $65 million of expense related to the retirement of RKI's debt.

Overview

The following table presents our production volumes and financial highlights for the three and nine months ended September 30, 2016 and 2015:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Production Sales Data(a):				
Volumes:				
Oil (MBbls)	3,576	3,123	11,069	8,927
Natural gas (MMcf)	18,845	16,901	54,428	47,646
NGLs (MBbls)	1,047	733	2,663	1,588
Combined equivalent volumes (MBoe)(b)	7,764	6,673	22,804	18,457
Per day volumes:				
Oil (MBbls/d)	38.9	33.9	40.4	32.7
Natural gas (MMcf/d)	205	184	199	175
NGLs (MBbls/d)	11.4	8.0	9.7	5.8
Per day combined equivalent volumes (MBoe/d)(b)	84.4	72.5	83.2	67.6
Financial Data (millions):				
Total revenues	$251	$ 407	$605	$ 981
Operating income (loss)	$(301)	$ 33	$(510)	$ 201
Cash capital expenditures(c)	$149	$ 211	$440	$ 890
Capital expenditure activity(d)	$160	$ 205	$424	$ 640

(a) Excludes production from discontinued operations.

(b) MBoe are converted using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.

(c) Includes cash capital expenditures related to discontinued operations of $1 million and $49 million for the three months ended September 30, 2016 and 2015, respectively, and $32 million and $234 million for the nine months ended September 30, 2016 and 2015, respectively.

(d) Includes capital expenditures activity related to discontinued operations of $1 million and $41 million for the three months ended September 30, 2016 and 2015, respectively, and $27 million and $155 million for the nine months ended September 30, 2016 and 2015, respectively.

Our third-quarter 2016 operating results were $334 million unfavorable compared to third-quarter 2015. The primary items impacting the three months ended September 30, 2016 compared to the same period in 2015 include:

- $238 million loss recorded on the divestment of transportation contracts in 2016;
- $167 million unfavorable change in net gain (loss) on derivatives;
- $46 million decrease in exploration costs for 2016 compared to 2015;
- $25 million increase in product revenues; and
- $23 million acquisition costs included in 2015 expenses.

Our year-to-date 2016 operating results were $711 million unfavorable compared to year to date 2015. The primary items impacting the nine months ended September 30, 2016 compared to the same period in 2015 include:

- $298 million unfavorable change in net gain (loss) on derivatives;
- $89 million increase in depreciation, depletion and amortization;
- $68 million lower net gas management margin;
- $38 million lower exploration costs for 2016 compared to 2015;
- $25 million of net loss on sales of assets and divestment of transportation contracts (see Note 5 of Notes to Consolidated Financial Statements) in 2016 compared to $279 million gain for the same period in 2015;
- $23 million acquisition costs included in 2015 expenses; and
- $22 million other expense in 2015 for a termination and settlement agreement to release us from a crude oil transportation and sales agreement.

Outlook

The oil and gas industry is in a challenging environment as evidenced by volatility in the prices, the changing capital plans among our peers, reductions in workforces across the industry and concerns about liquidity. In 2016, we have taken steps to strengthen our liquidity including the issuance of common equity which provided $538 million of proceeds net of offering costs, renegotiated a secured revolving credit agreement with a $1.025 billion current capacity, and sold WPX Energy Rocky Mountain LLC, which holds our Piceance operations. Our September 30, 2016 liquidity totaled over $1.6 billion, reflecting $623 million of cash and cash equivalents and $1.025 available under the Credit Facility. Through September 30, 2016, we have reduced our near term leverage through repayment of outstanding amounts at December 31, 2015 under the Credit Facility and tendering for portions of the Senior Notes due in 2017 of which only $125 million remains outstanding as of September 30, 2016. Our next debt maturity is not until 2020. In July 2016, we completed the divestment of transportation contracts that included approximately $400 million of remaining long term transportation obligations for a net payment of $238 million. In addition, we have 30,403 Bbl per day of oil hedged at $60.13 per barrel in 2016. For 2017, we have 34,554 Bbl per day of oil hedged at $51.45 per barrel. Our current liquidity position will provide the necessary capital to develop our assets or should sustain us if there is a further downturn. Over the past two years, we have been committed to the strategy of increasing oil production as a percentage of our overall production and increasing margins. This commitment has led to the transformation of the Company. Our primary focus is on the Delaware Basin assets acquired in 2015. The asset scale and concentrated acreage position will allow for efficient, low-cost development activities over a number of years that will provide additional optionality to our portfolio and a more balanced commodity mix. A substantial portion of our future capital spending will be allocated to the Delaware Basin where expected returns are attractive even in the current commodity price environment. We will also continue our development of the oil plays in the Williston and San Juan Basins.

As we continue our transformation, we have the opportunity to improve our cost structure and ensure that our organization is in alignment with our growth objectives. Throughout 2016 and into 2017, we plan to continue the cost reduction efforts through reduced drilling times, efficient use of pad design and completion activities, and collaboration with our vendors to lower costs on goods and services; however, additional savings may not be as great as those seen in the past. Additionally, we continue to challenge our levels of general and administrative costs. In February 2016, we announced our plans to close the Oklahoma City office which was accomplished in second-quarter 2016. Towards the end of the third quarter, we also had further reductions to our cost structure after completion of transition services associated with the sale of the Piceance Basin. We continue to further align our organizational size to achieve an optimal workforce conducive to the current pricing environment and future growth.

During the first nine months of 2016, we incurred $424 million in capital expenditures, primarily drilling and completions, but also includes $60 million for additional acreage acquisitions in the Delaware Basin and $27 million associated with the Piceance assets through the closing date. Our 2016 drilling and completion capital program is expected to range from $400 million to $450 million. For the full-year 2016, we expect to spend $195 million to $215 million in the Delaware Basin while running an average of three rigs to develop our acreage for the remainder of 2016 but ramping up to a total of five rigs by the end of the year. We expect to spend $130 million to $145 million in the Williston Basin and deploy one to two rigs during the fourth quarter. In addition, we expect to complete three to four previously drilled but not completed wells per month through December 2016. We expect to spend $75 million to $85 million in the San Juan Basin, primarily in the Gallup Sandstone. We also expect to incur additional capital expenditures of $10 million to $20 million on midstream related projects in the Delaware Basin.

Our 2017 drilling and completion capital program is expected to range from $800 million to $860 million. Approximately half of the capital is targeted for development in the Delaware Basin. This program would fund an eight-rig program, with five in the Delaware Basin, two in the Williston Basin and one in the San Juan Basin. In 2017, we expect to complete more than 150 operated wells under this plan consisting of roughly 70-80 Delaware wells, 38-42 Williston wells and 40-46 San Juan wells.

As we execute on our long-term strategy, we continue to operate with a focus on increasing shareholder value and investing in our businesses in a way that enhances our competitive position by:

- continuing to grow our oil production and reserves through the development of our positions in the Delaware Basin, Williston Basin and Gallup Sandstone in the San Juan Basin;
- continuing to pursue cost improvements and efficiency gains;
- employing new technology and operating methods;
- continuing to invest in projects to assess resources and add new development opportunities to our portfolio;
- retaining the flexibility to make adjustments to our planned levels and allocation of capital investment expenditures in response to changes in economic conditions or business opportunities; and
- continuing to maintain an active economic hedging program around our commodity price risks.

Potential risks or obstacles that could impact the execution of our plan include:

- lower than anticipated energy commodity prices;
- lower than expected results from acquisitions;
- higher capital costs of developing our properties;
- lower than expected levels of cash flow from operations;
- counterparty credit and performance risk;
- general economic, financial markets or industry downturn;
- unavailability of capital either under our revolver or access to capital markets;
- changes in the political and regulatory environments;
- increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation; and
- decreased drilling success.

With the exception of potential impairments, we continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we use master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements. Further, we continue to monitor the long-term market outlooks and forecasts for potential indicators of needed changes to our forecasted oil and natural gas prices. Commodity prices are significantly volatile and prices for a barrel of oil ranged from over $100 per barrel to less than $30 per barrel for a brief time over the past five years. Our forecasted price assumptions reflect a long term view of pricing but also consider current prices and are consistent with pricing assumptions generally used in evaluating our drilling decisions and acquisition plans. If forecasted oil and natural gas prices were to decline, we would need to review the producing properties net book value for possible impairment. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded. If impairments were required, the charges could be significant. The net book value of our predominantly oil proved properties is $3.7 billion and the net book value of our predominantly natural gas proved properties is approximately $300 million. In addition, the net book value associated with unproved leasehold is approximately $2.3 billion and is primarily associated with our Delaware Basin properties. See our discussion of impairment of long-lived assets in our critical accounting estimates discussion in Exhibit 99.1 of our Form 8-K filed May 25, 2016.

Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing oil and gas properties, we enter into derivative contracts for a portion of our future production (see Note 12 of Notes to Consolidated Financial Statements). We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. For the remainder of 2016 and 2017, we have the following contracts as of the date of this filing shown at weighted average volumes and basin-level weighted average prices:

Crude Oil	Oct - Dec 2016		2017	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Fixed Price Swaps—WTI	30,403	$ 60.13	34,554	$ 51.45
Swaptions—WTI	—	$ —	3,264	$ 51.22
Fixed Price Calls—WTI	1,900	$ 50.70	4,500	$ 56.47
Basis swaps—Midland	5,000	$ (0.45)	—	$ —

Natural Gas	Oct - Dec 2016		2017	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Fixed Price Swaps—Henry Hub	146	$ 3.93	170	$ 3.02
Swaptions—Henry Hub	—	$ —	65	$ 4.19
Fixed Price Calls—Henry Hub	—	$ —	16	$ 4.50
Basis swaps—Permian	38	$ (0.17)	68	$ (0.20)
Basis swaps—San Juan	100	$ (0.18)	103	$ (0.18)

Results of Operations

Operations of our company include oil, natural gas and NGL development, production and gas management activities primarily located in Texas, North Dakota, New Mexico and Colorado. Our development and production techniques specialize in production from tight-sands and shale formations in the Delaware, Williston and San Juan Basins. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, which include the management of various commodity contracts, such as transportation and related derivatives and the marketing of Piceance Basin volumes during a transition period which ended June 30, 2016 (see Note 3 of Notes to Consolidated Financial Statements).

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended September 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Revenues:				
Oil sales	$139	$120	$ 19	16 %
Natural gas sales	37	37	—	— %
Natural gas liquid sales	12	6	6	100 %
Total product revenues	188	163	25	15 %
Gas management	25	35	(10)	(29)%
Net gain (loss) on derivatives	38	205	(167)	(81)%
Other	—	4	(4)	NM
Total revenues	$251	$407	$ (156)	(38)%

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NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Significant variances in the respective line items of revenues are comprised of the following:

- $19 million increase in oil sales primarily reflects a $17 million increase related to higher production sales volumes for the three months ended September 30, 2016 as compared to 2015. The increase in production sales volumes relates to our Delaware Basin which was acquired on August 17, 2015. The Delaware Basin volumes were 14.3 MBbls per day for the three months ended September 30, 2016 compared to 4.6 MBbls per day for the three months ended September 30, 2015. The following table reflects oil production prices and volumes for the three months ended September 30, 2016 and 2015:

	Three months ended September 30,	
	2016	2015
Oil sales (per barrel)	$38.71	$38.23
Impact of net cash received related to settlement of derivatives (per barrel)(a)	12.15	32.98
Oil net price including derivative settlements (per barrel)	$50.86	$71.21
Oil production sales volumes (MBbls)	3,576	3,123
Per day oil production sales volumes (MBbls/d)	38.9	33.9

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- Natural gas sales remained flat as lower sales prices were offset by increased production sales volumes. The increase in our production sales volumes is primarily due to our Delaware Basin which was acquired on August 17, 2015. The following table reflects natural gas production prices and volumes for the three months ended September 30, 2016 and 2015:

	Three months ended September 30,	
	2016	2015
Natural gas sales (per Mcf)	$1.97	$2.18
Impact of net cash received related to settlement of derivatives (per Mcf)(a)	0.79	3.32
Natural gas net price including derivative settlements (per Mcf)	$2.76	$5.50
Natural gas production sales volumes (MMcf)	18,845	16,901
Per day natural gas production sales volumes (MMcf/d)	205	184

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $6 million increase in natural gas liquids sales reflects a $3 million increase related to production sales volumes, primarily due to our Delaware Basin which was acquired on August 17, 2015, and $3 million related to higher NGL sales prices for the three month ended September 30, 2016 compared to 2015. The following table reflects NGL production prices and volumes for the three months ended September 30, 2016 and 2015:

	Three months ended September 30,	
	2016	2015
NGL sales (per barrel)	$11.50	$8.76
NGL production sales volumes (MBbls)	1,047	733

Per day NGL production sales volumes (MBbls/d)	11.4	8.0

- $10 million decrease in gas management revenues primarily due to lower natural gas sales volumes partially offset by higher average prices on physical natural gas sales. We experienced a similar decrease of $12 million in related gas management costs and expenses, discussed below.
- $167 million unfavorable change in net gain (loss) on derivatives primarily relates to unfavorable changes in realized and unrealized gains (losses) on derivatives related to production. Net settlements from our derivatives were $59 million and $155 million for the three months ended September 30, 2016 and 2015, respectively.

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Cost and operating expense and operating income (loss) analysis

	Three months ended September 30, 2016 (Millions)	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Costs and expenses:				
Lease and facility operating	$ 40	$ 34	$ (6)	(18)%
Gathering, processing and transportation	19	17	(2)	(12)%
Taxes other than income	14	14	—	— %
Gas management, including charges for unutilized pipeline capacity	31	43	12	28 %
Exploration	10	56	46	82 %
Depreciation, depletion and amortization	150	136	(14)	(10)%
Net (gain) loss on sales of assets and divestment of transportation contracts	227	(2)	(229)	NM
General and administrative	51	45	(6)	(13)%
Acquisition costs	—	23	23	100 %
Other—net	10	8	(2)	(25)%
Total costs and expenses	$ 552	$ 374	$ (178)	(48)%
Operating income (loss)	$ (301)	$ 33	$ (334)	NM

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Significant variances in our costs and expenses are comprised of the following:

- $6 million increase in lease and facility operating expenses primarily related to our Delaware Basin, which was acquired on August 17, 2015, partially offset by decreases in other basins. Lease and facility operating expenses for the three months ended September 30, 2016 and 2015 included $15 million and $7 million, respectively, from our Delaware Basin. Lease and facility operating expense averaged $5.07 per Boe for the three months ended September 30, 2016 and 2015.
- $2 million increase in gathering, processing and transportation expenses is primarily due to the sales of our Williston Basin gathering system in the fourth quarter of 2015 and our San Juan Basin gathering system in the first quarter of 2016. Gathering, processing and transportation expenses averaged $2.51 per Boe for the three months ended September 30, 2016 and $2.53 per Boe for the same period in 2015.
- Taxes other than income remained flat for the three months ended September 30, 2016 compared to 2015. Taxes related to our Delaware Basin, which was acquired on August 17, 2015, were offset by a lower rate in the Williston

Basin. Taxes other than income averaged $1.84 per Boe for the three months ended September 30, 2016 compared to $2.06 per Boe for the same period in 2015.

- $12 million decrease in gas management expenses is primarily due to lower natural gas purchase volumes partially offset by higher average prices on physical natural gas cost of sales, as previously discussed. Also included in gas management expenses is $6 million and $8 million for the three months ended September 30, 2016 and 2015, respectively, for unutilized pipeline capacity.
- $46 million decrease in exploration expenses is primarily due to 2015 dry hole costs and impairments of exploratory area well costs and unproved leasehold property impairment, amortization and expiration related to a non-core exploratory play where we no longer intend to continue exploration activities.
- $14 million increase in depreciation, depletion and amortization is primarily due to higher production volumes from our Delaware Basin, which was acquired on August 17, 2015, partially offset by a lower rate in 2016. The lower rate is due in part to our adjusting the proved reserves used for the calculation of depletion and amortization to reflect current estimates based on recent well performance resulting in approximately $10 million of lower depreciation, depletion and amortization. This decrease was more than offset by the $7 million and $5 million increases in the first and second quarters of 2016, respectively, due to our adjusting the proved reserves used for the calculation of depletion and amortization to reflect the impact of an increase in the 12 month average price for those periods. Future decreases or increases in the 12-month average price may result in increases or decreases in our depreciation, depletion and amortization expense. During the three months ended September 30, 2016, our depreciation, depletion and amortization averaged $19.30 per Boe compared to an average $20.37 per Boe for the same period in 2015.

- In 2016, we recorded a $238 million loss on the divestment of transportation contracts (see Note 5 of Notes to Consolidated Financial Statements).
- General and administrative expenses include $3 million and $1 million for the three months ended September 30, 2016 and 2015, respectively, for severance and relocation costs associated with workforce reductions. We continue to challenge our levels of general and administrative costs, and we plan to further align our organizational size to achieve an optimal workforce conducive to the current pricing environment and future growth. Costs associated with non-cash equity based compensation was $10 million and $7 million for the three months ended September 30, 2016 and 2015, respectively. General and administrative expenses averaged $6.50 per Boe for the three months ended September 30, 2016 compared to $6.72 per Boe for the same period in 2015. Excluding the severance and relocation costs and equity-based compensation, general and administrative expenses averaged $4.92 per Boe for 2016 and $5.54 per Boe for 2015.
- The absence of $23 million of acquisition costs in 2015 related to the acquisition of RKI (see Note 2 of Notes to Consolidated Financial Statements).

Results below operating income (loss)

	Three months ended September 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$(301)	$33	$ (334)	NM
Interest expense	(49)	(65)	16	25 %
Loss on extinguishment of acquired debt	—	(65)	65	100 %
Income (loss) from continuing operations before income taxes	(350)	(97)	(253)	NM
Provision (benefit) for income taxes	(132)	(27)	105	NM
Income (loss) from continuing operations	(218)	(70)	(148)	NM
Income (loss) from discontinued operations	(1)	(160)	159	99 %
Net income (loss) attributable to WPX Energy, Inc.	$(219)	$(230)	$ 11	5 %

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NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

The decrease in interest expense primarily relates to $16 million of fees in 2015 associated with acquisition bridge financing arrangements related to the Acquisition. No borrowings were made under the acquisition bridge financing arrangements.

The loss on extinguishment of debt in 2015, including a make whole premium, related to the satisfaction and discharge of RKI's senior notes at the time of the closing of the Acquisition.

Provision (benefit) for income taxes changed favorably due to a greater pre-tax loss for the three months ended September 30, 2016 compared to the same period in 2015. See Note 8 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income (loss) from discontinued operations in 2016 changed favorably as the sale of the Piceance Basin closed in second-quarter 2016 and the three months ended September 30, 2015 includes $15 million loss on the sale or the Powder River basin and $187 million recorded upon the exit of the Powder River Basin related to obligations under pipeline capacity, gathering and treating agreements. See Note 3 of Notes to Consolidated Financial Statements for detail of amounts included in discontinued operations.

Nine Month-Over-Nine Month Results of Operations
Revenue Analysis

	Nine months ended September 30,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2016	2015		
	(Millions)			
Revenues:				
Oil sales	$378	$370	$ 8	2 %
Natural gas sales	86	104	(18)	(17)%
Natural gas liquid sales	27	14	13	93 %
Total product revenues	491	488	3	1 %
Gas management	172	248	(76)	(31)%
Net gain (loss) on derivatives	(59)	239	(298)	NM
Other	1	6	(5)	(83)%
Total revenues	$605	$981	$ (376)	(38)%

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NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Significant variances in the respective line items of revenues are comprised of the following:

- $8 million increase in oil sales reflects $88 million increase related to higher production sales volumes substantially offset by a $80 million related to lower sales prices for the nine months ended September 30, 2016 compared to 2015. The increase in production sales volumes relates to our Delaware Basin which was acquired on August 17, 2015. The Delaware Basin volumes were 13.4 MBbls per day for the first nine months of 2016 compared to 1.6 MBbls per day for 2015. The following table reflects oil production prices and volumes for the nine months ended September 30, 2016 and 2015:

	Nine months ended September 30,	
	2016	2015
Oil sales (per barrel)	$34.14	$41.39
Impact of net cash received related to settlement of derivatives (per barrel)(a)	14.42	30.14
Oil net price including derivative settlements (per barrel)	$48.56	$71.53
Oil production sales volumes (MBbls)	11,069	8,927
Per day oil production sales volumes (MBbls/d)	40.4	32.7

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $18 million decrease in natural gas sales reflects $33 million related to lower sales prices partially offset by a $15 million increase related to higher production sales volumes for the nine months ended September 30, 2016 compared to 2015. The increase in our production sales volumes is due in part to our Delaware Basin which was acquired on August 17, 2015. The increase in sales volumes is partially offset by the impact of the sale of Appalachian Basin assets in the first quarter of 2015. The following table reflects natural gas production prices and volumes for the nine months ended September 30, 2016 and 2015:

	Nine months ended September 30,	
	2016	2015
Natural gas sales (per Mcf)	$ 1.58	$ 2.18
Impact of net cash received related to settlement of derivatives (per Mcf)(a)	1.83	3.88
Natural gas net price including derivative settlements (per Mcf)	$ 3.41	$ 6.06
Natural gas production sales volumes (MMcf)	54,428	47,646
Per day natural gas production sales volumes (MMcf/d)	199	175

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(a) Included in net gain (loss) on derivatives on the Consolidated Statements of Operations.

- $13 million increase in natural gas liquids sales is primarily due to production sales volumes in our Delaware Basin, which was acquired on August 17, 2015. The following table reflects NGL production prices and volumes for the nine months ended September 30, 2016 and 2015:

	Nine months ended September 30,	
	2016	2015
NGL sales (per barrel)	$ 10.24	$ 9.20
NGL production sales volumes (MBbls)	2,663	1,588
Per day NGL production sales volumes (MBbls/d)	9.7	5.8

- $76 million decrease in gas management revenues is primarily due to lower average prices on physical natural gas sales partially offset by higher natural gas sales volumes. The increase in volumes is due in part to the sale of production volumes pursuant to our purchase agreement with the buyer of the Piceance Basin operations. This agreement ended June 30, 2016. The decrease in the sales price was greater than the decrease in the purchase price as reflected in the $8 million decrease in related gas management costs and expenses, discussed below.
- $298 million unfavorable change in net gain (loss) on derivatives primarily reflects an unfavorable change in gains (losses) on natural gas and crude derivatives related to production, primarily natural gas and crude, partially offset by a favorable change in gains (losses) on derivatives related to gas management. Settlements from our derivatives totaled $260 million for the nine months ended September 30, 2016 and net settlements were $422 million for the nine months ended September 30, 2015.

Cost and operating expense and operating income (loss) analysis

	Nine months ended September 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Costs and expenses:				
Lease and facility operating	$123	$101	$ (22)	(22)%
Gathering, processing and transportation	55	50	(5)	(10)%
Taxes other than income	41	45	4	9 %
Gas management, including charges for unutilized pipeline capacity	202	210	8	4 %
Exploration	31	69	38	55 %
Depreciation, depletion and amortization	465	376	(89)	(24)%
Net (gain) loss on sales of assets and divestment of transportation contracts	25	(279)	(304)	NM
General and administrative	159	152	(7)	(5)%
Acquisition costs	—	23	23	NM
Other—net	14	33	19	58 %
Total costs and expenses	$1,115	$780	$ (335)	(43)%
Operating income (loss)	$(510)	$201	$ (711)	NM

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NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Significant variances in our costs and expenses are comprised of the following:

- $22 million increase in lease and facility operating expenses primarily related to our Delaware Basin which was acquired on August 17, 2015 partially offset by reduced costs across our basins. Lease and facility operating expenses for the nine months ended September 30, 2016 and 2015, included $49 million and $7 million, respectively, from our Delaware Basin. Lease and facility operating expense averaged $5.37 per Boe for the nine months ended September 30, 2016 compared to $5.49 per Boe for the same period in 2015.
- $4 million decrease in taxes other than income primarily relates to lower commodity prices and a lower rate in the Williston Basin partially offset by the addition of the Delaware Basin, which was acquired on August 17, 2015. Taxes other than income averaged $1.79 per Boe for the nine months ended September 30, 2016 compared to $2.43 per Boe for the same period in 2015.
- $8 million decrease in gas management expenses is primarily due to lower average prices on physical natural gas cost of sales, as previously discussed, and lower crude purchase volumes partially offset by higher natural gas purchase volumes. Also included in gas management expenses are $27 million for both the nine months ended September 30, 2016 and 2015, respectively, for unutilized pipeline capacity.
- $38 million decrease in exploration expenses is primarily due to 2015 dry hole costs and impairments of exploratory area well costs and unproved leasehold property impairment, amortization and expiration related to a non-core exploratory play where we no longer intend to continue exploration activities.
- $89 million increase in depreciation, depletion and amortization is primarily due to higher volumes in our Delaware Basin, which was acquired on August 17, 2015, partially offset by lower volumes in our other basins in 2016. The rate per Boe includes the impact of adjusting the proved reserves used for the calculation of depletion and amortization to reflect the impact of a decrease in the 12-month average price in the first and second quarters of 2016, partially offset by additional reserves in the third-quarter of 2016, reflecting current estimates based on recent well performance. Future decreases or increases in the 12-month average price may result in increases or decreases in our depreciation, depletion and amortization expense. During the nine months ended September 30, 2016, our depreciation, depletion and amortization averaged $20.40 per Boe compared to an average $20.37 per Boe for the same period in 2015.
- $25 million net loss on sales of assets and divestment of transportation contracts in 2016 primarily related to a $238 million loss on the divestment of transportation obligations offset by a net $215 gain on the sale of the San Juan Basin

gathering system. The $279 million net gain in 2015 primarily related to a $209 million gain on the sale of a package of marketing contracts and release of certain related firm transportation capacity in the second quarter of 2015 and a net gain of $69 million on the sale of a portion of our Appalachian Basin assets in the first quarter of 2015. (See Note 5 of Notes to Consolidated Financial Statements).

- General and administrative expenses include $13 million and $16 million for the nine months ended September 30, 2016 and 2015, respectively, for severance and relocation costs associated with workforce reductions and office consolidations. We continue to challenge our levels of general and administrative costs, and we plan to further align our organizational size to achieve an optimal workforce conducive to the current pricing environment and future growth. Costs associated with non-cash equity-based compensation was $25 million and $24 million for the nine months ended September 30, 2016 and 2015, respectively. General and administrative expenses averaged $6.97 per Boe for the nine months ended September 30, 2016 compared to $8.18 per Boe for the same period in 2015. Excluding the severance and relocation costs and equity-based compensation, general and administrative expenses would have averaged $5.31 per Boe for 2016 and $5.98 per Boe for 2015.
- $23 million of acquisition costs in 2015 related to the acquisition of RKI (see Note 2 of Notes to Consolidated Financial Statements.)
- $19 million decrease in other expenses primarily related to expenses recorded in association with a contract termination in the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).

Results below operating income (loss)

	Nine months ended September 30, 2016	2015	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$(510)	$201	$ (711)	NM
Interest expense	(159)	(130)	(29)	(22)%
Loss on extinguishment of acquired debt	—	(65)	65	NM
Investment income and other	1	2	(1)	(50)%
Income (loss) from continuing operations before income taxes	(668)	8	(676)	NM
Provision (benefit) for income taxes	(227)	3	230	NM
Income (loss) from continuing operations	(441)	5	(446)	NM
Income (loss) from discontinued operations	12	(197)	209	NM
Net income (loss)	(429)	(192)	(237)	123 %
Less: Net income (loss) attributable to noncontrolling interests	—	1	(1)	(100)%
Net income (loss) attributable to WPX Energy, Inc.	$(429)	$(193)	$ (236)	122 %

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

The increase in interest expense primarily relates to the notes issued in the third quarter of 2015, partially offset by $16 million of fees expensed in 2015 associated with acquisition bridge financing arrangements related to the Acquisition.

The loss on extinguishment of debt in 2015, including a make whole premium, related to the satisfaction and discharge of RKI's senior notes at the time of the closing of the Acquisition.

Provision (benefit) for income taxes in 2016 changed favorably compared to 2015 due to a pre-tax loss from continuing operations in 2016 compared to pre-tax income in 2015. See Note 8 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income (loss) from discontinued operations in 2016 changed favorably as the sale of the Piceance Basin closed in second-quarter 2016 resulting in a net gain of $53 million. Discontinued operation for 2015 include a $15 million loss on the sale of the Powder River Basin and $187 million recorded upon the exit of the Powder River Basin related to obligations for pipeline capacity, gathering and treating agreements. See Note 3 of Notes to Consolidated Financial Statements for detail of amounts included in discontinued operations.

Management’s Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

Our main sources of liquidity are cash on hand, internally generated cash flow from operations and our bank credit facility. Additional sources of liquidity, if needed and if available, include proceeds from asset sales, bank financings and proceeds from the issuance of long-term debt and equity securities. In consideration of our liquidity, we note the following:

- as of September 30, 2016, we maintained liquidity through cash, cash equivalents and available credit capacity under our credit facility; and
- our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support.

Outlook

We expect our capital structure will provide us financial flexibility to meet our requirements for working capital, capital expenditures and tax and debt payments while maintaining a sufficient level of liquidity. Our primary sources of liquidity in 2016 are expected cash flows from operations, proceeds from the issuance of equity securities, proceeds from monetization of assets and, if necessary, borrowings on our credit facility. We anticipate that the combination of these sources should be sufficient to allow us to pursue our business strategy and goals through 2018.

We note the following assumptions for the remainder of 2016:

- our planned capital expenditures, excluding acquisitions and Piceance related capital, for all of 2016 are estimated to be approximately $400 million to $450 million. As of September 30, 2016, we have incurred $397 million of capital expenditures, including $60 million for land acquisitions, and an additional $27 million related to the Piceance Basin;
- we seek to further reduce debt and we may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. As of September 30, 2016, the remaining outstanding balance of the Senior Notes due in 2017 was $125 million. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors; and
- for the remainder of 2016 we have hedged 30,403 Bbls per day of our anticipated 2016 oil production at a weighted-average price of $60.13 per barrel. WPX has natural gas derivatives totaling 145,510 MMBtu per day for the remainder of 2016, at a weighted price of $3.93 per MMBtu. WPX has hedged 34,554 Bbls per day of our anticipated 2017 oil production at a weighted-average price of $51.45 per barrel. We have also hedged 170,000 MMBtu per day of our anticipated 2017 natural gas production at a weighted-average price of $3.02 per MMBtu.

Potential risks associated with our planned levels of liquidity and the planned capital expenditures discussed above include:

- lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices;
- higher than expected collateral obligations that may be required;
- higher capital costs for developing our properties;
- significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold;
- reduced access to our credit facility pursuant to our financial covenants; and
- higher than expected operating costs.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses throughout 2016 and beyond. In addition, we continually evaluate the level of our 2016 capital program given our expectations of our cash on hand and forecasted cash flows for the remainder of 2016. Our internal and external sources of consolidated liquidity include cash generated from operations, cash and cash equivalents on hand, and our available credit facility capacity. Additional sources of liquidity, if needed and if available, include proceeds from asset sales, bank financings and proceeds from the issuance of long-term debt and equity securities.

Equity Offering

On June 6, 2016, we completed an underwritten public offering of 56.925 million shares of our common stock, which included 7.425 million shares of common stock issued pursuant to an option granted to the underwriters to purchase additional shares. The stock was sold to the underwriters at $9.47 per share and we received proceeds of approximately $538 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions (see Note 10 of Notes to Consolidated Financial Statements).

Credit Facility

On March 18, 2016, the Company entered into a Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the “Credit Facility”). The Credit Facility is a senior secured revolving credit facility with $1.2 billion in commitments and a maturity date of October 28, 2019. Since the time of closing of the Credit Facility, a Collateral Trigger Period has been in effect. During a Collateral Trigger Period, Loans will be subject to a Borrowing Base as calculated in accordance with the provisions of the Credit Facility. As of October 2016, the Borrowing Base was reaffirmed at $1.025 billion and will remain in effect until the next date the Borrowing Base is re-determined pursuant to the Credit Facility. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of September 30, 2016, we were in compliance with our financial covenants, had full access to the Credit Facility and did not have any outstanding borrowings. For additional information regarding the terms of our Credit Facility see Note 7 of Notes to Consolidated Financial Statements.

We currently have three bilateral, uncommitted letter of credit agreements most of which expire during 2016. These agreements allow us to preserve our liquidity under our Credit Facility while providing support to our ability to meet performance obligation needs for, among other items, various interstate pipeline contracts into which we have entered. These unsecured agreements incorporate similar terms as those in the Credit Facility. As a result of the divestment of our Piceance Basin transportation contracts, we eliminated approximately $162 million in letters of credit and their associated annual interest expense. At September 30, 2016, a total of $66 million in letters of credit have been issued, a majority of which provide support for interstate pipeline contracts. As these letter of credit agreements expire, we expect to issue letters of credit under our Credit Facility.

Sources (Uses) of Cash

	Nine months ended September 30,	
	2016	2015
	(Millions)	
Net cash provided (used) by:		
Operating activities	$109	$629
Investing activities	460	(1,259)
Financing activities	16	659
Increase (decrease) in cash and cash equivalents	$585	$29

Operating activities

Our net cash provided by operating activities for the nine months ended September 30, 2016 decreased from the same period in 2015 primarily due to an unfavorable change in net settlements related to derivatives, lower net gas management revenues and expenses, income taxes paid in 2016 and lower commodity prices, partially offset by higher production volumes. Excluding changes in working capital, total cash provided by operating activities related to discontinued operations was approximately $28 million for the nine months ended September 30, 2016. Excluding changes in working capital, total cash used by operating activities related to discontinued operations was approximately $56 million for the nine months ended September 30, 2015.

Investing activities

Cash capital expenditures for drilling and completions were $351 million and $774 million for the nine months ended September 30, 2016 and 2015, respectively. Cash capital expenditures for drilling and completions related to our Piceance Basin were $26 million and $204 million for the nine months ended September 30, 2016 and 2015, respectively. Capital expenditures incurred for drilling and completions were $342 million and $555 million during the nine months ended September 30, 2016 and 2015, respectively. Capital expenditures incurred for drilling and completions related to our Piceance Basin were $22 million and $142 million during the nine months ended September 30, 2016 and 2015, respectively. In addition, expenditures related to international were $15 million for the nine months ended September 30, 2015.

Cash provided by investing activities in 2016 was also impacted by a $238 million divestment of certain transportation contracts (see Note 9 of Notes to the Consolidated Financial Statements). Cash used by investing activities in 2015 also includes $209 million for the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast during May 2015 (see Note 5 of Notes to Consolidated Financial Statements). On August 17, 2015 we successfully closed the purchase of RKI and paid approximately $1.2 billion in cash, net of cash acquired and net of certain distributions.

Significant components related to proceeds from the sale of our domestic assets and international interests are comprised of the following:

2016

•$862 million for the sale of WPX Energy Rocky Mountain, LLC that held our Piceance Basin operations to Terra Energy Partners, LLC (see Note 3 of Notes to Consolidated Financial Statements).

•$280 million for the sale of our San Juan Basin gathering system to a portfolio company of ISQ Global Infrastructure Fund, a fund managed by I Squared Capital during the first quarter of 2016 (see Note 5 of Notes to Consolidated Financial Statements).

2015

•$50 million for the portion of our Powder River Basin asset sale that closed in the third quarter of 2015 (see Note 3 of Notes to Consolidated Financial Statements).

•$271 million for the sale of a portion of our Appalachian Basin operations and release of certain firm transportation capacity to Southwestern Energy Company during the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).

•$291 million after expenses but before $17 million of cash on hand at Apco as of the closing date, for the divestiture of our 69 percent controlling equity interest in Apco and additional Argentina-related assets to Pluspetrol (see Note 3 of Notes to Consolidated Financial Statements).

Financing activities

2016

On June 6, 2016, we completed an equity offering of 56.925 million shares of our common stock for net proceeds of approximately $538 million.

Net cash provided by financing activities for the nine months ended September 30, 2016 also reflects net repayments under the Credit Facility of $265 million, $230 million repayment of our Senior Notes due 2017, $15 million of preferred stock dividends, and $10 million of cash paid as an inducement for the conversion of preferred stock to common stock.

2015

On July 22, 2015 we completed equity offerings of 30 million shares of our common stock for net proceeds of approximately $292 million and 6.25% series A mandatory convertible preferred stock for net proceeds of approximately $339 million.

On July 22, 2015, we completed a debt offering of (a) $500 million aggregate principal amount of 7.500% senior unsecured notes due 2020 and (b) $500 million aggregate principal amount of 8.250% senior unsecured notes due 2023.

Cash provided by financing activities for the nine months ended September 30, 2015 also included cash used to retire $600 million of outstanding debt on RKI's revolving credit facility and $455 million for the satisfaction and discharge of RKI's senior notes which included a $55 million make-whole premium.

Net cash provided by financing activities for the nine months ended September 30, 2015 was also impacted by borrowings under the Credit Facility in excess of repayments. In August, 2015 we utilized borrowings under the credit facility for the acquisition of RKI.

Contractual Obligations

In conjunction with the sale of our San Juan Basin gathering system, our contractual obligations increased for gathering services to be provided by the purchaser over a ten-year period. These obligations totaled approximately $363 million as of September 30, 2016.

Following the sale of our Piceance Basin operations and the subsequent divestment of the remaining transportation contracts in the Piceance Basin (see Note 9 of Notes to Consolidated Financial Statements), our total contractual obligations for transportation and storage decreased from approximately $686 million as of December 31, 2015 to approximately $128 million as of September 30, 2016.

Off-Balance Sheet Financing Arrangements

We had no guarantees of off-balance sheet debt to third parties or any other off-balance sheet arrangements at September 30, 2016 or at December 31, 2015.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our current interest rate risk exposure is related primarily to our debt portfolio and has not materially changed during the first nine months of 2016.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of oil, natural gas and natural gas liquids as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our marketing trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted and changes in interest rates. See Notes 11 and 12 of Notes to Consolidated Financial Statements.

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte Carlo method to simulate hypothetical movements in future market prices and assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The simulation method uses historical correlations and market forward prices and volatilities. In applying the value-at-risk methodology, we do not consider that the simulated hypothetical movements affect the positions or would cause any potential liquidity issues, nor do we consider that changing the portfolios in response to market conditions could affect market prices and could take longer than a one-day holding period to execute. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk given market liquidity and our own credit and liquidity constraints.

We segregate our derivative contracts into trading and nontrading contracts, as defined in the following paragraphs. We calculate value at risk separately for these two categories. Contracts designated as normal purchases or sales and nonderivative energy contracts have been excluded from our estimation of value at risk.

We have policies and procedures that govern our trading and risk management activities. These policies cover authority and delegation thereof in addition to control requirements, authorized commodities and term and exposure limitations. Value-at-risk is limited in aggregate and calculated at a 95 percent confidence level.

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was zero at September 30, 2016 and December 31, 2015. The value at risk for contracts held for trading purposes was zero at September 30, 2016 and December 31, 2015.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our energy commodity purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $13 million and $344 million at September 30, 2016 and December 31, 2015, respectively.

The value at risk for derivative contracts held for nontrading purposes was $34 million at September 30, 2016 and $19 million at December 31, 2015. During the last 12 months, our value at risk for these contracts ranged from a high of $34 million to a low of $19 million.

Item 4. Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (“Disclosure Controls”) or our internal control over financial reporting (“Internal Controls”) will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people or by management override of the control. The design of any system of controls is also based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and Internal Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls and Internal Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Changes in Internal Control over Financial Reporting

There have been no changes in internal controls during the third quarter of 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings
See Note 9 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.
Item 1A. Risk Factors
Risk Factor resulting from the June 2016 Equity Offering
Our ability to utilize our net operating loss (“NOL”) carryovers for income tax purposes to reduce future taxable income will be limited if we undergo an ownership change.
Beginning with our 2015 tax year, we generated an NOL that is being carried forward to future years. In the event that we were to undergo an “ownership change” (as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the “Code”)), our NOL carryovers generated prior to the ownership change would be subject to annual limitations, which could defer or eliminate our ability to utilize these tax losses against future taxable income. Generally, an “ownership change” occurs if one or more shareholders, each of whom owns 5% or more in value of a corporation’s stock, increase their aggregate percentage ownership by more than 50% over the lowest percentage of stock owned by those shareholders at any time during the preceding three-year period. Although we do not anticipate an “ownership change” resulting in limitations under Section 382 on the use of our NOLs for income tax purposes, future changes in the ownership of our stock could result in the application of such limitations.
In addition, Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 2015, includes certain risk factors that could materially affect our business, financial condition or future results. Those risk factors have not materially changed as of September 30, 2016.
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
Not applicable.
Item 5. Other Information
Not applicable.

EXHIBITS

Exhibit No.	Description
2.1**	Agreement and Plan of Merger, dated October 2, 2014, by and among Pluspetrol Resources Corporation, Pluspetrol Black River Corporation and Apco Oil and Gas International Inc. (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on October 7, 2014)
2.2**	Agreement and Plan of Merger, dated as of July 13, 2015, by and among RKI Exploration & Production, LLC, WPX Energy, Inc. and Thunder Merger Sub LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
2.3**	Membership Interest Purchase Agreement by and Among WPX Energy Holdings, LLC, as Seller, WPX Energy, Inc., solely for purposes of Section 14.15, and Terra Energy Partners LLC, as Purchaser, dated February 8, 2016 (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 9, 2016)
3.1	Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on January 6, 2012)
3.2	Certificate of Amendment of Amended and Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
3.3	Amended and Restated Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on March 21, 2014)
3.4	Certificate of Designations for 6.25% Series A Mandatory Convertible Preferred Stock (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
4.1	Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.'s Current Report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011)
4.2	Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.3	First Supplemental Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.4	Second Supplemental Indenture, dated as of July 22, 2015, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)

10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on January 6, 2012)
10.4	Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 23, 2012) (1)
10.5	Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 23, 2012) (1)

Exhibit No.	Description
10.6	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 29, 2013) (1)
10.7	WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc.’s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011) (1)
10.8	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.9	Form of Restricted Stock Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.10	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.11	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2015) (1)
10.12	Form of Stock Option Agreement between WPX Energy, Inc. and Section 16 Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014) (1)
10.13	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.16 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.14	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.17 to WPX Energy, Inc.’s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.15	Retirement Agreement, dated December 16, 2013, between WPX Energy, Inc. and Ralph A. Hill (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on December 17, 2013)
10.16	Employment Agreement, dated April 29, 2014, between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.17	Form of Nonqualified Stock Option Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.18	

	Form of 2014 Time-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.19	Form of 2014 Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.20	Form of Time-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.5 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.21	Form of Performance-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.6 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.22	Form of Restricted Stock Unit Award between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)

Exhibit No.	Description
10.23	Separation and Release Agreement, dated July 28, 2014, between WPX Energy, Inc. and James J. Bender (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.24	WPX Energy Executive Severance Pay Plan (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 19, 2014) (1)
10.25	Amended and Restated Credit Agreement, dated as of October 28, 2014, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on November 3, 2014)
10.26	Form of Voting and Support Agreement, dated as of July 13, 2015, by and between WPX Energy, Inc. and the Member signatory thereto (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
10.27	First Amendment to the Amended and Restated Credit Agreement, dated as of July 16, 2015, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as existing Administrative Agent and existing Swingline Lender, and Wells Fargo Bank, National Association, as successor Administrative Agent and successor Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
10.28	Commitment Increase Agreement for Amended and Restated Credit Agreement, dated as of July 31, 2015, among WPX Energy, Inc., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, and the Issuing Banks thereto (incorporated by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on August 6, 2015)
10.29	Registration Rights Agreement dated August 17, 2015, among WPX Energy, Inc. and the signatures thereto (incorporated herein by reference to Exhibit 10.35 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2015)
10.30	Second Amendment to the Amended and Restated Credit Agreement, dated as of March 18, 2016, by and among WPX Energy, Inc., as the borrower thereunder, the financial institutions party thereto from time to time, as lenders, and Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on March 22, 2016)
10.31	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.32 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016) (1)
10.32	Form of Severance and Restrictive Covenant Agreement between WPX Energy, Inc. and Marcia MacLeod (incorporated herein by reference to Exhibit 10.33 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2016) (1)
10.33*	

	Form of Severance and Restrictive Covenant Agreement between WPX Energy, Inc. and Michael Fiser (1)
12*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith

** All schedules to the Merger Agreement have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule and/or exhibit will be furnished to the SEC upon request

(1) Management contract or compensatory plan or arrangement

SIGNATURE

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.

WPX Energy, Inc.
(Registrant)

By: /s/ Stephen L. Faulkner
Stephen L. Faulkner
Controller
(Principal Accounting Officer)

Date: November 3, 2016

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