

WPX ENERGY, INC.  
Form 10-Q  
November 05, 2015

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

Form 10-Q  
(Mark One)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT  
 OF 1934

For the quarterly period ended September 30, 2015

OR  
 TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT  
OF 1934

For the transition period from to  
Commission file number 1-35322

WPX Energy, Inc.  
(Exact Name of Registrant as Specified in Its Charter)

Delaware 45-1836028  
(State or Other Jurisdiction of (IRS Employer  
Incorporation or Organization) Identification No.)

3500 One Williams Center, 74172-0172  
Tulsa, Oklahoma (Zip Code)

(Address of Principal Executive Offices)  
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  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer  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   
The number of shares outstanding of the registrant's common stock at November 4, 2015 were 275,276,052.



WPX Energy, Inc.  
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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;
- expansion and growth of our business and operations;
- financial condition and liquidity;
- business strategy;
- estimates of proved gas and oil reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations or results of operations;
- acquisitions or divestitures;
- seasonality of our business; and



natural gas, NGLs and crude oil prices and demand.

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 natural gas and oil 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, 2014.

WPX Energy, Inc.  
Consolidated Balance Sheets  
(Unaudited)

	September 30, 2015	December 31, 2014
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	\$99	\$ 41
Accounts receivable, net of allowance of \$5 million as of September 30, 2015 and \$6 million as of December 31, 2014	298	459
Derivative assets	369	498
Inventories	71	45
Margin deposits	2	27
Assets classified as held for sale	70	773
Other	28	26
Total current assets	937	1,869
Properties and equipment (successful efforts method of accounting)	15,382	11,753
Less—accumulated depreciation, depletion and amortization	(5,567)	(4,911)
Properties and equipment, net	9,815	6,842
Derivative assets	85	38
Other noncurrent assets	70	49
Total assets	\$10,907	\$ 8,798
Liabilities and Equity		
Current liabilities:		
Accounts payable	\$413	\$ 712
Accrued and other current liabilities (Note 3)	283	177
Liabilities associated with assets held for sale	1	132
Deferred income taxes	65	151
Derivative liabilities	10	37
Total current liabilities	772	1,209
Deferred income taxes	1,255	621
Long-term debt	3,400	2,280
Derivative liabilities	2	5
Asset retirement obligations	230	198
Other noncurrent liabilities (Note 3)	176	57
Contingent liabilities and commitments (Note 9)		
Equity:		
Stockholders' equity:		
Preferred stock (100 million shares authorized at \$0.01 par value; 7 million shares issued at September 30, 2015)	339	—
Common stock (2 billion shares authorized at \$0.01 par value; 275.3 million shares issued at September 30, 2015 and 203.7 million shares issued at December 31, 2014)	3	2
Additional paid-in-capital	6,167	5,562
Accumulated deficit	(1,437)	(1,244)
Accumulated other comprehensive income (loss)	—	(1)
Total stockholders' equity	5,072	4,319
Noncontrolling interests in consolidated subsidiaries	—	109

Total equity	5,072	4,428
Total liabilities and equity	\$10,907	\$ 8,798
See accompanying notes.		

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

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
	(Millions, except per-share amounts)			
Revenues:				
Product revenues:				
Natural gas sales	\$ 146	\$ 201	\$ 440	\$ 780
Oil and condensate sales	124	199	386	542
Natural gas liquid sales	24	53	72	168
Total product revenues	294	453	898	1,490
Gas management	35	145	250	937
Net gain (loss) on derivatives (Note 12)	205	148	239	(64 )
Other	3	1	6	5
Total revenues	537	747	1,393	2,368
Costs and expenses:				
Lease and facility operating	50	63	158	182
Gathering, processing and transportation	75	82	217	249
Taxes other than income	17	32	58	100
Gas management, including charges for unutilized pipeline capacity (Note 5)	43	164	211	788
Exploration (Note 5)	56	28	69	97
Depreciation, depletion and amortization	242	201	685	596
Net (gain) loss on sales of assets (Note 5)	(1 )	—	(279 )	—
Loss on sale of working interests in the Piceance Basin (Note 5)	—	1	—	196
General and administrative	54	71	181	208
Acquisition costs (Note 2)	23	—	23	—
Other—net	7	3	38	6
Total costs and expenses	566	645	1,361	2,422
Operating income (loss)	(29 )	102	32	(54 )
Interest expense (Note 2)	(65 )	(31 )	(130 )	(88 )
Loss on extinguishment of acquired debt (Note 2)	(65 )	—	(65 )	—
Investment income and other	1	—	3	—
Income (loss) from continuing operations before income taxes	(158 )	71	(160 )	(142 )
Provision (benefit) for income taxes	(52 )	25	(53 )	(44 )
Income (loss) from continuing operations	(106 )	46	(107 )	(98 )
Income (loss) from discontinued operations	(124 )	20	(85 )	50
Net income (loss)	(230 )	66	(192 )	(48 )
Less: Net income (loss) attributable to noncontrolling interests	—	4	1	7
Comprehensive income (loss) attributable to WPX Energy, Inc.	(230 )	62	(193 )	(55 )
Less: Dividends on preferred stock	4	—	4	—
Net income (loss) attributable to WPX Energy, Inc. common stockholders	\$(234 )	\$ 62	\$(197 )	\$(55 )
Amounts attributable to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	\$(110 )	\$ 46	\$(111 )	\$(98 )
Income (loss) from discontinued operations	(124 )	16	(86 )	43
Net income (loss)	\$(234 )	\$ 62	\$(197 )	\$(55 )
Basic and diluted earnings (loss) per common share (Note 4):				
Income (loss) from continuing operations	\$(0.44 )	\$ 0.23	\$(0.50 )	\$(0.48 )



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Income (loss) from discontinued operations	(0.49	)	0.07	(0.39	)	0.21
Net income (loss)	\$(0.93	)	\$0.30	\$(0.89	)	\$(0.27 )
Basic weighted-average shares	251.2		203.3	220.3		202.5
Diluted weighted-average shares	251.2		207.5	220.3		202.5
See accompanying notes.						

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

	WPX Energy, Inc., Stockholders				Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests in Consolidated Subsidiaries (a)	Total Equity
	Preferred Stock	Common Stock	Additional Paid-In- Capital	Accumulated Deficit				
	(Millions)							
Balance at December 31, 2014	\$—	\$2	\$ 5,562	\$ (1,244 )	\$ (1 )	\$ 4,319	\$ 109	\$4,428
Comprehensive income (loss):								
Net income (loss)	—	—	—	(193 )	—	(193 )	1	(192 )
Comprehensive income (loss)								(192 )
Stock based compensation	—	—	18	—	—	18	—	18
Issuance of common stock to public, net of offering costs	—	—	292	—	—	292	—	292
Issuance of common stock related to an acquisition		1	295			296		296
Issuance of preferred stock to public, net of offering costs	339	—	—	—	—	339	—	339
Impact of divestitures					1	1	(110 )	(109 )
Balance at September 30, 2015	\$339	\$3	\$ 6,167	\$ (1,437 )	\$ —	\$ 5,072	\$ —	\$5,072

(a) Primarily represents the 31 percent interest in Apco Oil and Gas International Inc. owned by others. See accompanying notes.

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

	Nine months ended September 30,	
	2015	2014
	(Millions)	
Operating Activities		
Net income (loss)	\$(192 )	\$(48 )
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	685	638
Deferred income tax provision (benefit)	(138 )	(55 )
Provision for impairment of properties and equipment (including certain exploration expenses)	78	95
Amortization of stock-based awards	27	26
Loss on extinguishment of acquired debt and acquisition bridge financing fees	81	—
(Gain) loss on sales of international interests and domestic assets	(317 )	195
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	232	71
Inventories	(11 )	1
Margin deposits and customer margin deposits payable	25	(22 )
Other current assets	—	16
Accounts payable	(186 )	(15 )
Accrued and other current liabilities	22	(22 )
Changes in current and noncurrent derivative assets and liabilities	183	(106 )
Other, including changes in other noncurrent assets and liabilities	140	5
Net cash provided by operating activities	629	779
Investing Activities		
Capital expenditures(a)	(890 )	(1,325 )
Proceeds from sales of international interests and domestic assets	819	389
Purchases of business, net of cash acquired	(1,190 )	—
Other	2	(3 )
Net cash provided by (used in) investing activities	(1,259 )	(939 )
Financing Activities		
Proceeds from common stock	295	15
Proceeds from preferred stock	339	—
Proceeds from long-term debt	1,000	500
Borrowings on credit facility	756	1,451
Payments on credit facility	(636 )	(1,816 )
Payments for retirement of acquired debt	(1,055 )	—
Payments for debt issuance costs and acquisition bridge financing fees	(40 )	(6 )
Other	—	(12 )
Net cash provided by (used in) financing activities	659	132
Net increase (decrease) in cash and cash equivalents	29	(28 )
Effect of exchange rate changes on cash and cash equivalents	—	(6 )
Cash and cash equivalents at beginning of period(b)	70	99
Cash and cash equivalents at end of period	\$99	\$65
<hr/>		
(a) Increase to properties and equipment	\$(640 )	\$(1,389 )
Changes in related accounts payable and accounts receivable	(250 )	64
Capital expenditures	\$(890 )	\$(1,325 )

(b) For periods prior to sale, amounts include cash associated with our international operations and represents the difference between amounts reported as cash on the Consolidated Balance Sheet.

See accompanying notes.

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WPX Energy, Inc.

Notes to Consolidated Financial Statements

Note 1. Basis of Presentation and Description of Business

Description of Business

Operations of our company include natural gas, oil and NGL development, production and gas management activities primarily located in Colorado, New Mexico, North Dakota and Texas in the United States. We specialize in development and production from tight-sands and shale formations in the Piceance, Williston and San Juan Basins and we have recently entered the core of the Permian's Delaware Basin through our acquisition of RKI Exploration & Production, LLC ("RKI"). See Note 2 for additional information regarding this acquisition. 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, coupled with the sale of our commodity volumes.

In addition, we had operations in the Powder River Basin in Wyoming which were sold on September 1, 2015 and, until January 29, 2015, we had a 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. For all periods presented, the results of Powder River Basin and Apco are reported as discontinued operations.

The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as "WPX" or the "Company," is at times referred to in the first person as "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, 2014 in the Company's Annual Report on Form 10-K. 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, 2015, results of operations for the three and nine months ended September 30, 2015 and 2014, changes in equity for the nine months ended September 30, 2015 and cash flows for the nine months ended September 30, 2015 and 2014.

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 are comprised of a single business segment, which includes the development, production and gas management activities of natural gas, oil and NGLs in the United States. Prior to classifying our international operations as discontinued operations, we reported business segments for domestic and international.

Discontinued Operations

On September 1, 2015, we completed the sale of our Powder River Basin operations in Wyoming. The results of operations of the Powder River Basin have been reported as discontinued operations on the Consolidated Statements of Operations and the assets and liabilities have been classified as held for sale on the Consolidated Balance Sheet as of December 31, 2014.

On January 29, 2015, we completed the disposition of our international interests. The results of operations of our international segment have been reported as discontinued operations on the Consolidated Statements of Operations and the assets and liabilities have been classified as held for sale on the Consolidated Balance Sheet as of December 31, 2014.

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 Williams' former power business (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. 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 is effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. The

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

Company is currently evaluating the impact, if any, of ASU 2014-09 to the Company's financial position, results of operations or cash flows.

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 its Consolidated Financial Statements or related disclosures.

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. The core principles of the guidance in ASU 2015-03 require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the guidance in this update. ASU 2015-03 is effective for annual reporting periods beginning after December 15, 2015, including interim periods within that reporting period. The Company does not believe the adoption of this guidance will have a material impact on its financial position, results of operations or cash flows. As of September 30, 2015, we have \$47 million in debt issuance costs which is reported in Other noncurrent assets on the Consolidated Balance Sheets.

In September 2015, the FASB issued ASU 2015-16, Simplifying the Accounting for Measurement-Period Adjustments that eliminates the requirement for an acquirer in a business combination to account for measurement-period adjustments retrospectively. Under the ASU, acquirers must recognize measurement-period adjustments during the period in which they determine the amounts, including the effect on earnings of any amounts they would have recorded in previous periods if the accounting had been completed at the acquisition date. The ASU does not change the criteria for determining whether an adjustment qualifies as a measurement-period adjustment and does not change the length of the measurement period. ASU 2015-16 is effective for the annual reporting period beginning after December 15, 2015, including interim period within those fiscal years. Early adoption is permitted for any interim and annual financial statements that have not yet been made available for issuance. The Company is currently evaluating the impact, if any, of ASU 2015-16 to the Company's financial position, results of operations or cash flows.

#### Note 2. Acquisition

On August 17, 2015, we completed the acquisition of privately held RKI. Per the terms of the merger agreement, the purchase price was \$2.75 billion, consisting of 40 million unregistered shares of WPX common stock and approximately \$2.28 billion in cash (the "Acquisition"). The cash consideration was subject to closing adjustments and was reduced by our assumption of \$400 million of aggregate principal amount of RKI's senior notes and amounts outstanding under RKI's revolving credit facility along with other working capital items. The closing adjustments are subject to change as closing estimates are finalized. We incurred approximately \$23 million of acquisition-related costs, primarily related to legal and advisory fees which are reflected on a separate line item on the Consolidated Statements of Operations. In addition, we incurred \$16 million of acquisition bridge facility fees, included in interest expense and a \$65 million loss on extinguishment of RKI's senior notes, reflected as a separate line in the Consolidated Statements of Operations.

RKI was engaged in the acquisition, exploration, development and production of oil and natural gas properties located onshore in the continental United States, concentrated primarily in the Permian Basin, and more specifically the Delaware Basin sub-area, which span parts of New Mexico and Texas. RKI also had oil and gas properties in the Powder River Basin. In connection with the Acquisition, RKI contributed its Powder River Basin assets and other properties outside the Delaware Basin to a wholly owned RKI subsidiary, the ownership interests of which were distributed to RKI's equity holders in connection with the Acquisition. Thus, we acquired RKI exclusive of the Powder River Basin assets and other properties outside the Delaware Basin.

The majority of RKI's Delaware Basin leasehold is located in Loving County, Texas and Eddy County, New Mexico. RKI's assets in the Permian Basin include approximately 92,000 net acres in the core of the Permian's Delaware Basin. RKI operated 659 gross producing wells in the Delaware Basin with an average working interest of approximately 93

percent. RKI's average net daily production from its Delaware Basin properties for the year ended December 31, 2014 was 18.7 MBoe per day, 43 percent of which was oil, 23 percent NGLs and 34 percent natural gas. As of December 31, 2014, RKI reported proved reserves in the Delaware Basin of 101.5 MMBoe, 40 percent of which was oil, 25 percent NGLs and 35 percent natural gas.

WPX funded the Acquisition with proceeds from a combination of debt, preferred stock and common stock offerings along with available cash on hand and borrowings under its revolving credit facility. See Notes 7 and 10 for further discussion on the financing of this transaction.



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

The following table presents the unaudited pro forma financial results for the nine months ended September 30, 2015 and 2014 as if the Acquisition and related financings had been completed January 1, 2014. In addition, the nine months ended September 30, 2015 have been adjusted to exclude \$23 million of acquisition costs, \$65 million loss on extinguishment of acquired debt and \$16 million of acquisition bridge facility fees. 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 periods presented, nor is such information indicative of the Company's expected future results of operations.

	Nine Months Ended September 30,	
	2015	2014
	(millions)	
Revenues	\$1,606	\$2,618
Net income (loss) from continuing operations attributable to WPX Energy, Inc.	\$(21)	\$(80)

The Acquisition qualified as a business combination, and as a result, we must estimate the fair value of the underlying shares distributed, the assets acquired and the liabilities assumed as of the August 17, 2015 Acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. We will use a combination of market data, discounted cash flow models and replacement estimates in determining the fair value of the oil and gas properties and the related midstream assets. All of which will include estimates and assumptions such as future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs. Deferred taxes must also be recorded for any differences between the assigned values and tax bases of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the Acquisition date, although such estimates may change in the future as additional information becomes known.

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

The initial accounting for the Acquisition is preliminary and adjustments to provisional amounts for properties and equipment, certain accrued receivables and liabilities and related deferred taxes or recognition of additional assets acquired or liabilities assumed may occur as additional information is obtained about facts and circumstances that existed at the Acquisition date. In addition, the cash consideration is subject to change due to post-closing adjustments to the working capital estimates at the time of closing. Such adjustments could result in the recognition of goodwill which would be subject to impairment review. The following table summarizes the consideration paid for the Acquisition and the preliminary estimates of fair value of the assets acquired and liabilities assumed as of the Acquisition date. The purchase price allocation is preliminary and subject to adjustment, specifically post-closing working capital adjustments, finalization of the valuation of oil and gas properties and midstream assets and deferred taxes. These amounts will be finalized as soon as possible, but no later than September 30, 2016.

	Purchase Price Allocation (Millions)
Consideration:	
Cash	\$1,263
Fair value of WPX common stock issued	296
Total consideration	\$1,559
Fair value of liabilities assumed:	
Accounts payable	\$90
Accrued liabilities	77
Deferred income taxes, current	34
Deferred income taxes, noncurrent	646
Long-term debt	990
Asset retirement obligation	22
Total liabilities assumed as of September 30, 2015	1,859
Fair value of assets acquired:	
Cash and cash equivalents	51
Accounts receivable, net	75
Derivative assets, current	97
Derivative assets, noncurrent	34
Inventories	14
Other current assets	3
Properties and equipment	3,140
Other noncurrent assets	4
Total assets acquired as of September 30, 2015	3,418
Net fair values	\$1,559

Note 3. Discontinued Operations

On October 3, 2014, we announced an agreement to sell our international interests for approximately \$294 million subject to the successful consummation of the definitive merger agreement entered into between Pluspetrol Resources Corporation and Apco. On January 29, 2015 we completed this divestiture 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.

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

In August 2015 we signed agreements for the sale of our Powder River Basin for \$80 million, subject to closing adjustments. On September 1, 2015, we completed a portion of the Powder River Basin divestiture. The remaining portion of the divestiture, which relates to our equity method investment in Fort Union Gas Gathering, LLC, closed on October 30, 2015. We recorded a pretax loss of \$15 million related to this transaction 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 related to the Powder River properties sold with total commitments of \$104 million through 2020. These commitments had been in excess of our production throughput. We also have certain pipeline capacity obligations held by our marketing company with total commitments through 2021 totaling \$150 million, which were related to the Powder River Operation. With the closing of the Powder River Basin sale and exiting this basin, we recorded \$187 million of expense related to these contracts and included as a separate line below. This \$187 million expense is the estimated present value of the remaining \$254 million in payments associated with these contracts as of the Powder River Basin sales date, and includes the fair value of estimated recoveries from potential third parties and discounting based on our risk adjusted borrowing rate. Offsetting liabilities of \$54 million and \$133 million are recorded in accrued and other current liabilities and other noncurrent liabilities, respectively. During the third quarter of 2014, we had signed an agreement to sell our Powder River Basin holdings. This sales agreement did not successfully close in March 2015 and we subsequently terminated the transaction with the counterparty. During third quarter 2015, we received \$13 million in escrow funds as a result of the terminated contract and this amount is included in Other-net expense below.

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

## Summarized Results of Discontinued Operations

	Three months ended September 30, 2015	Three months ended September 30, 2014		
	Powder River Basin (Millions)	Powder River Basin	International	Total
Total revenues	\$12	\$41	\$47	\$88
Costs and expenses:				
Lease and facility operating	\$6	\$11	\$10	\$21
Gathering, processing and transportation	10	16	—	16
Taxes other than income	1	4	8	12
Exploration	—	—	1	1
Depreciation, depletion and amortization	—	3	12	15
General and administrative	4	1	4	5
Accrual for contract obligations retained	187	—	—	—
Other—net	(14	) —	—	—
Total costs and expenses	194	35	35	70
Operating income (loss)	(182	) 6	12	18
Investment income and other	2	2	6	8
Loss on sale of Powder River Basin	(15	) —	—	—
Income (loss) from discontinued operations before income taxes	(195	) 8	18	26
Provision (benefit) for income taxes	(71	) 2	4	6
Income (loss) from discontinued operations	\$(124	) \$6	\$14	\$20

	Nine months ended September 30, 2015		
	Powder River Basin	International	Total
		(Millions)	
Total revenues	\$54	\$15	\$69
Costs and expenses:			
Lease and facility operating	\$23	\$4	\$27
Gathering, processing and transportation	38	—	38
Taxes other than income	5	3	8
Impairment of assets held for sale	16	—	16
General and administrative	5	1	6
Accrual for contract obligations retained	187	—	187
Other—net	(14	) —	(14
Total costs and expenses	260	8	268
Operating income (loss)	(206	) 7	(199
Investment income and other	5	1	6
Loss on sale of Powder River Basin	(15	) —	(15
Gain on sale of international assets	—	41	41
Income (loss) from discontinued operations before income taxes	(216	) 49	(167
Provision (benefit) for income taxes (a)	(79	) (3	) (82
Income (loss) from discontinued operations	\$(137	) \$52	\$(85

(a) International includes the reversal of certain U.S. deferred tax liabilities associated with Apco.

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

	Nine months ended September 30, 2014		
	Powder River Basin	International (Millions)	Total
Total revenues	\$ 151	\$ 117	\$ 268
Costs and expenses:			
Lease and facility operating	\$ 32	\$ 26	\$ 58
Gathering, processing and transportation	51	1	52
Taxes other than income	12	21	33
Exploration	—	4	4
Depreciation, depletion and amortization	11	31	42
General and administrative	3	11	14
Other—net	—	3	3
Total costs and expenses	109	97	206
Operating income (loss)	42	20	62
Investment income and other	5	13	18
Income (loss) from discontinued operations before income taxes	47	33	80
Provision (benefit) for income taxes	17	13	30
Income (loss) from discontinued operations	\$ 30	\$ 20	\$ 50
Assets and Liabilities Classified as Held for Sale on the Consolidated Balance Sheet			

As of September 30, 2015, the following table presents assets classified as held for sale and liabilities associated with assets held for sale related to our Powder River Basin investment in Fort Union Gas Gathering, LLC and Van Hook gathering system.

	September 30, 2015 Total (Millions)
Assets classified as held for sale	
Investments in Fort Union Gas Gathering, LLC	\$ 16
Total assets classified as held for sale—discontinued operations	\$ 16
Total assets classified as held for sale—continuing operations (Note 5)	54
Total assets classified as held for sale on the Consolidated Balance Sheets	\$ 70
Liabilities associated with assets held for sale	
Total liabilities associated with assets held for sale—continuing operations (Note 5)	\$ 1
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	\$ 1

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

As of December 31, 2014 the following table presents domestic assets classified as held for sale and liabilities associated with assets held for sale related to our Powder River Basin and Appalachian Basin operations, and the international assets classified as held for sale and liabilities associated with assets held for sale related to our international operations which were divested in January 2015.

	December 31, 2014		
	Domestic	International	Total
	(Millions)		
Assets classified as held for sale			
Current assets:			
Cash and cash equivalents	\$—	\$29	\$29
Accounts receivable	—	25	25
Inventories	1	7	8
Other	—	14	14
Total current assets	1	75	76
Investments	18	134	152
Properties and equipment, net(a)	122	217	339
Other noncurrent assets	—	6	6
Total assets classified as held for sale—discontinued operations	\$141	\$432	\$573
Total assets classified as held for sale—continuing operations (Note 5)	200	—	200
Total assets classified as held for sale on the Consolidated Balance Sheets	\$341	\$432	\$773
Liabilities associated with assets held for sale			
Current liabilities:			
Accounts payable	\$—	\$34	\$34
Accrued and other current liabilities	3	23	26
Total current liabilities	3	57	60
Deferred income taxes	—	13	13
Long-term debt	—	2	2
Asset retirement obligations	45	7	52
Other noncurrent liabilities	—	3	3
Total liabilities associated with assets held for sale—discontinued operations	\$48	\$82	\$130
Total liabilities associated with assets held for sale—continuing operations (Note 5)	\$2	\$—	\$2
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	\$50	\$82	\$132

(a) Domestic includes a total of \$45 million in impairments of the net assets held for sale of the Powder River Basin.

#### Cash Flows Attributable to Discontinued Operations

Excluding income taxes and changes to working capital, total cash used by operating activities related to the Powder River Basin was \$12 million for the nine months ended September 30, 2015 and total cash provided by operating activities was \$58 million for the nine months ended September 30, 2014. Total cash used in investing activities related to Powder River Basin discontinued operations was \$4 million and \$9 million for the nine months ended September 30, 2015 and 2014, respectively. Cash provided by operating activities related to our international operations was \$3 million and \$77 million for the nine months ended September 30, 2015 and 2014, respectively. Total cash used in investing activities related to our international operations was \$15 million and \$61 million for the

nine months ended September 30, 2015 and 2014, respectively.



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, 2015		2014		Nine months ended September 30, 2015		2014	
	(Millions, except per-share amounts)							
Income (loss) from continuing operations attributable to WPX Energy, Inc.	\$ (106	)	\$ 46		\$ (107	)	\$ (98	)
Less: Dividends on preferred stock	\$ 4		\$ —		\$ 4		\$ —	
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	\$ (110	)	\$ 46		\$ (111	)	\$ (98	)
Basic weighted-average shares	251.2		203.3		220.3		202.5	
Effect of dilutive securities:								
Nonvested restricted stock units and awards	—		3.2		—		—	
Stock options	—		1.0		—		—	
Diluted weighted-average shares(a)	251.2		207.5		220.3		202.5	
Earnings (loss) per common share from continuing operations:								
Basic	\$ (0.44	)	\$ 0.23		\$ (0.50	)	\$ (0.48	)
Diluted	\$ (0.44	)	\$ 0.23		\$ (0.50	)	\$ (0.48	)

(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, 2015		2014		Nine months ended September 30, 2015		2014	
	(Millions)							
Weighted-average nonvested restricted stock units and awards	0.7		—		1.4		2.8	
Weighted-average stock options	0.1		—		0.1		1.0	
Common shares issuable upon assumed conversion of 6.25% Series A mandatory convertible preferred stock (Note 10)	26.7		—		9.0		—	

The table below includes information related to stock options that were outstanding at September 30, 2015 and 2014 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,	
	2015	2014
Options excluded (millions)	2.6	—
Weighted-average exercise price of options excluded	\$ 16.16	\$ —
Exercise price range of options excluded	\$ 11.46 - \$ 21.81	—
Third quarter weighted-average market price	\$ 8.36	\$ 23.67

For the nine months ended September 30, 2015, approximately 1.1 million 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

During August 2015, we agreed to sell a North Dakota gathering system for approximately \$185 million, subject to closing adjustments, to a private equity fund managed by the Ares EIF Group, a subsidiary of Ares Management, L.P. (NYSE: ARES). Under the terms of the agreement, a subsidiary of the buyer, Midstream Capital Partners, will manage the overall system and we will operate the system which currently gathers approximately 11,000 barrels per day of oil, approximately 6,500 Mcf per day of natural gas and approximately 5,000 barrels per day of water. Closing of this transaction is expected in the fourth quarter of 2015.

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 us from various long-term natural gas purchase and sales obligations and approximately \$390 million in 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, subject to 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. This transaction included physical operations covering approximately 46,700 acres, roughly 50 MMcfe per day of net natural gas production and 63 horizontal wells. The assets were primarily located in the Appalachian Basin in Susquehanna County, Pennsylvania. The transaction also included the release of firm transportation capacity that we had under contract in the Northeast, primarily 260 MMcfe per day with Millennium Pipeline. Upon the transfer of the firm capacity, we were released from approximately \$24 million per year in annual demand obligations associated with the transport.

During the second quarter of 2014, we completed the sale of a portion of our working interests in certain Piceance Basin wells. Based on an estimated total value received at closing of \$329 million which represented estimated final cash proceeds and an estimated fair value of incentive distribution rights we received, we recorded a \$195 million loss on the sale in the second quarter of 2014. An additional \$1 million loss on sale was recorded in the third quarter of 2014.

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, 2015		Nine months ended September 30, 2015	
	2015	2014	2015	2014
	(Millions)			
Geologic and geophysical costs	\$3	\$1	\$5	\$8
Dry hole costs and impairments of exploratory area well costs	22	6	22	21
Unproved leasehold property impairment, amortization and expiration	31	21	42	68
Total exploration expenses	\$56	\$28	\$69	\$97

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.

Dry hole costs and impairments of exploratory area well costs for the three and nine months ended September 30, 2014 includes \$6 million and \$16 million, respectively, of impairments of well costs in an exploratory area where management had determined to cease exploratory activities. The remaining amount represents dry hole costs associated with exploratory wells where hydrocarbons were not detected.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

Included in unproved leasehold property impairment, amortization and expiration for the three and nine months ended September 30, 2014, are impairments totaling \$15 million and \$41 million, respectively, for unproved leasehold costs in non-core exploratory areas where we no longer intend to continue exploration activities.

As of September 30, 2015, our total capitalized well costs associated with our exploratory areas, including the Niobrara Shale in the Piceance Basin, totaled approximately \$74 million.

Note 6. Inventories

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

	September 30, 2015	December 31, 2014
	(Millions)	
Material, supplies and other	\$68	\$43
Crude oil production in transit	3	2
Total inventories	\$71	\$45

Note 7. Debt and Banking Arrangements

The following table presents a summary of our debt as of the dates indicated below.

	September 30, 2015	December 31, 2014
	(Millions)	
5.250% Senior Notes due 2017	\$400	\$400
7.500% Senior Notes due 2020	500	—
6.000% Senior Notes due 2022	1,100	1,100
8.250% Senior Notes due 2023	500	—
5.250% Senior Notes due 2024	500	500
Credit facility agreement	400	280
Other	1	1
Total debt	\$3,401	\$2,281
Less: Current portion of long-term debt	1	1
Total long-term debt	\$3,400	\$2,280

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

### Senior Notes

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

The Notes are the Company's senior unsecured obligations ranking equally with the Company's other existing and future senior unsecured indebtedness. The 2020 Notes bear interest at a rate of 7.500% per annum, and the 2023 Notes bear interest at a rate of 8.250% per annum. Interest is payable on the Notes semiannually in arrears on February 1 and August 1 of each year commencing on February 1, 2016. The 2020 Notes will mature on August 1, 2020. The 2023 Notes will mature on August 1, 2023. At any time or from time to time prior to July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, the Company may, at its option, redeem the applicable series of Notes, in whole or in part, at a makewhole redemption price as set forth in the Indenture. The Company also has the option, at any time or from time to time on or after July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, to redeem some or all of the applicable series of Notes at a redemption price equal to 100% of the principal amount of the Notes to be redeemed, as more fully described in the Indenture. The Indenture contains covenants that, among other things, restrict the Company's ability to grant liens on its assets and merge, consolidate or transfer or lease all or substantially all of its assets, subject to certain qualifications and exceptions. See our Annual Report on Form 10-K for the year ended December 31, 2014 for a discussion of our previously issued senior notes.

### Credit Facility

Including the impact of amendments in July 2015, we have a \$1.75 billion five-year senior unsecured revolving credit facility 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 matures on October 28, 2019. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time.

On July 16, 2015, the Company amended its senior unsecured revolving credit facility to, among other things (a) modify the financial covenants in a manner favorable to the Company in respect of (i) the ratio of PV to Consolidated Indebtedness and (ii) the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX and (b) add a financial covenant requiring a minimum ratio of Consolidated EBITDAX to Consolidated Interest Charges (each capitalized term used herein but not defined is defined in the Company's revolving credit facility, as amended).

Under the amended revolving credit facility, if the Company's Corporate Rating is (a) BB- or worse by S&P and Ba3 or worse by Moody's or (b) B+ or worse by S&P or B1 or worse by Moody's, the Company will be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the Credit Facility, to Consolidated Indebtedness of at least 1.10 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and at least 1.50 to 1.00 thereafter unless and until (i) the Company's Corporate Rating is (A) BBB- or better with S&P (without negative outlook or negative watch) or (B) Baa3 or better by Moody's (without negative outlook or negative watch) and (ii) the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody's. As of the date of this filing our credit rating with S&P was BB, positive outlook and our credit rating with Moody's is Ba1, negative outlook.

In addition, the Company is required to maintain a ratio of Consolidated Net Indebtedness to Consolidated EBITDAX 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. The ratio of Consolidated Indebtedness to Consolidated Total Capitalization is not permitted to be greater than 60 percent and is applicable for the life of the agreement. Furthermore, the Company may not permit the ratio of Consolidated EBITDAX to Consolidated Interest Charges to be less than 2.50 to 1.00.

On July 31, 2015, the commitments from existing lenders were increased by \$250 million, for total commitments of \$1.75 billion.

As of September 30, 2015, we were in compliance with our financial covenants and had full access to the Credit Facility. For additional information regarding the terms of our Credit Facility prior to recent amendments, see our Annual Report on Form 10-K for the year ended December 31, 2014.

Letters of Credit

WPX has also entered into three bilateral, uncommitted letter of credit (“LC”) agreements. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility. At September 30, 2015, a total of \$239 million in letters of credit have been issued.

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

Note 8. Provision (Benefit) for Income Taxes

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

	Three months		Nine months	
	ended September 30, 2015	2014	ended September 30, 2015	2014
	(Millions)			
Current:				
Federal	\$ (4	) \$ (2	) \$ (4	) \$ 10
State	1	(2	) 1	—
	(3	) (4	) (3	) 10
Deferred:				
Federal	(46	) 26	(47	) (60
State	(3	) 3	(3	) 6
	(49	) 29	(50	) (54
Total provision (benefit)	\$ (52	) \$ 25	\$ (53	) \$ (44

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

The effective tax rate for the three and nine months ended September 30, 2014 differs from the federal statutory rate primarily due to the effects of state income taxes.

As a result of the sale of Apco in the first quarter of 2015, we no longer have foreign operations and the associated tax liabilities. The closing of Apco resulted in a \$42 million capital loss for which a valuation allowance was established in 2014.

Tax reform legislation was enacted by the state of New York on March 31, 2014, and had an impact on us as a result of our marketing activities in the state. As a result, we recorded an additional \$9 million of deferred tax expense in the first quarter of 2014 to accrue for the impact of this new legislation.

As of September 30, 2015, 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 The Williams Companies, Inc. (“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. 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 audit adjustments unrelated to our business. 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. It is uncertain when the IRS will complete that audit.

Note 9. Contingent Liabilities

Royalty litigation

In September 2006, royalty-interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County, Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for proceeds received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments related to calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class for certification, resolved claims relating to past calculation of royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim related to the issue of whether we are required to have proportionately increased the value of natural



gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are entitled to deduct a proportionate share of transportation costs in calculating royalty payments. Plaintiffs had claimed damages of approximately \$20 million plus interest for the period from July 2000 to July 2008. The court issued pretrial orders finding that we do bear the burden of demonstrating enhancement of the value of gas in order to deduct transportation costs and that the

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

enhancement test must be applied on a monthly basis in order to determine the reasonableness of post-production transportation costs. Trial occurred in December 2013 on the issue of whether we have met that burden. Following that trial, the court issued its order rejecting plaintiffs' proposed standard and accepting our position as to the methodology to use in determining the standard by which our activity should be judged. We have completed the accounting process under the standard and have obtained the court's approval. However, as we continue to believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law, we have appealed this matter to the Colorado Court of Appeals. Plaintiffs have now filed a second class action lawsuit in the District Court, Garfield County containing similar allegations but related to subsequent time periods. The parties have agreed to stay this new lawsuit pending resolution of the first lawsuit in the Colorado Court of Appeals.

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, 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. In March 2015, the court denied plaintiffs' motion for class certification. Plaintiffs have not timely filed an appeal of this denial. They have filed both a pending motion for reconsideration of the denial of class certification with the trial court which we oppose and a motion seeking to conduct additional discovery in order to attempt to redefine their proposed class, which has been denied. 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 injunction. 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. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR's assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR's predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From October 2008 through

September 2015, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately \$114 million.

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.

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

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. When a final order is entered against the one remaining defendant, the Colorado plaintiffs may appeal the order.

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 FERC 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 Western States 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. 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 exposures at this time.

Other Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, 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 breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At September 30, 2015, we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. 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, 2015 and December 31, 2014, the Company had accrued approximately \$18 million and \$16 million, respectively, 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.



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

Note 10. Stockholders' Equity

On July 22, 2015 we completed equity offerings of (a) 30 million shares of our common stock for gross proceeds of approximately \$303 million, before underwriter discounts and commissions of \$10.5 million, at the public offering price of \$10.10 per share and (b) \$350 million of aggregate liquidation preference of 6.25% series A mandatory convertible preferred stock ("Mandatory Convertible Preferred Stock") as further described below.

On August 17, 2015 we issued 40 million unregistered shares of our common stock to RKI shareholders as part of the consideration under our merger agreement. The estimated fair value of the shares was \$296 million. See Note 2 for further discussion of the Acquisition.

Common Stock

Each share of our common stock entitles its holder to one vote in the election of each director. No share of our common stock affords any cumulative voting rights. Holders of our common stock will be entitled to dividends in such amounts and at such times as our Board of Directors in its discretion may declare on our common stock out of funds legally available for the payment of dividends. No dividends on our common stock were declared or paid for 2015 or 2014. No shares of common stock are subject to redemption or have preemptive rights to purchase additional shares of our common stock or other securities.

Subject to certain exceptions, so long as any share of our Mandatory Convertible Preferred Stock remains outstanding, no dividend or distribution shall be declared or paid on the shares of the Company's common stock or any other class or series of junior stock, and no common stock or any other class or series of junior or parity stock shall be purchased, redeemed or otherwise acquired for consideration by the Company or any of its subsidiaries unless all accumulated and unpaid dividends for all preceding dividend periods have been declared and paid upon, or a sufficient sum of cash or number of shares of the Company's common stock has been set apart for the payment of such dividends upon, all outstanding shares of Mandatory Convertible Preferred Stock

Preferred Stock

Our amended and restated certificate of incorporation authorizes our Board of Directors to establish one or more series of preferred stock. Unless required by law or by any stock exchange on which our common stock is listed, the authorized shares of preferred stock will be available for issuance without further action. Rights and privileges associated with shares of preferred stock are subject to authorization by our Board of Directors and may differ from those of any and all other series at any time outstanding. As of September 30, 2015 there were 7 million shares of our 6.25% series A Mandatory Convertible Preferred Stock (as described below) issued and outstanding.

Series A Mandatory Convertible Preferred Stock

On July 22, 2015, we issued 7 million shares, \$0.01 par value, pursuant to a registered public offering, of our 6.25% Series A Mandatory Convertible Preferred Stock ("Mandatory Convertible Preferred Stock") at \$50 per share, for gross proceeds of approximately \$350 million, before underwriting discounts and commissions of \$10.5 million. The underwriters did not exercise their option to purchase additional shares.

Dividends on our Mandatory Convertible Preferred Stock will be payable on a cumulative basis when, as and if declared by our board of directors, or an authorized committee of our board of directors, at an annual rate of 6.25% of the liquidation preference of \$50 per share. We may pay declared dividends in cash or, subject to certain limitations, in shares of our common stock, or in any combination of cash and shares of our common stock on January 31, April 30, July 31 and October 31 of each year, commencing on October 31, 2015 and ending on, and including, July 31, 2018.

Each share of our Mandatory Convertible Preferred Stock has a liquidation preference of \$50 pursuant to the Certificate of Designations and unless converted or redeemed earlier each share of our Mandatory Convertible Preferred Stock will automatically convert on the mandatory conversion date, which is the third business day immediately following the last trading day of the final averaging period into between 4.1254 and 4.9504 shares of our common stock (respectively, the "minimum conversion rate" and "maximum conversion rate"), subject to anti-dilution adjustments. The number of shares of our common stock issuable on conversion will be determined based on the average volume weighted average price per share of our common stock over the 20 consecutive trading day period beginning on, and including, the 23rd scheduled trading day immediately preceding July 31, 2018, which we refer to

as the “final averaging period.” Other than during a fundamental change conversion period, at any time prior to July 31, 2018, a holder may convert one share of our Mandatory Convertible Preferred Stock into a number of shares of our common stock equal to the minimum conversion rate of 4.1254, subject to anti-dilution adjustments. If a holder converts one share of our Mandatory Convertible Preferred Stock during a specified period beginning on the effective date of a fundamental change (as described in the offering documents), the conversion rate will be adjusted under certain circumstances, and such holder will also be entitled to a make-whole dividend amount (as described in the offering documents).

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

On October 2, 2015 our Board of Directors approved a quarterly dividend of \$0.85938 per share to holders of our Mandatory Convertible Preferred Stock. The dividend was paid on November 2, 2015, to holders of record of our Mandatory Convertible Preferred Stock at the close of business on October 15, 2015.

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, 2015				December 31, 2014			
	Level 1 (Millions)	Level 2	Level 3	Total	Level 1 (Millions)	Level 2	Level 3	Total
Energy derivative assets	\$3	\$451	\$—	\$454	\$14	\$517	\$5	\$536
Energy derivative liabilities	\$4	\$8	\$—	\$12	\$32	\$10	\$—	\$42
Total debt(a)	\$—	\$3,031	\$—	\$3,031	\$—	\$2,218	\$—	\$2,218

(a) The carrying value of total debt, excluding capital leases, was \$3,400 million and \$2,280 million as of September 30, 2015 and December 31, 2014, respectively.

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 or as 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 exchange-traded 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 monthly 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

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

included in Level 3 were a net asset of less than \$1 million at September 30, 2015, 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, 2015 and 2014.

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 natural gas, oil and natural gas liquids attributable to commodity price risk.

We produce, buy and sell natural gas, crude oil 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 natural gas, crude oil 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 put options which guarantee a minimum price sold, call options which limit value to a ceiling price, zero-cost collars which guarantee value between a floor and ceiling price, or swaptions which convert to a swap when market price exceeds a ceiling price.

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements and financial option contracts to mitigate the price risk associated with these contracts. Derivatives for transportation contracts economically hedge the expected cash flows generated by those agreements.

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

Derivatives related to production

The following table sets forth the derivative notional volumes that are economic hedges of production volumes, which are included in our commodity derivatives portfolio as of September 30, 2015.

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)	Weighted Average Price (c)
Natural Gas					
Natural Gas	Oct -Dec 2015	Fixed Price Swaps	Henry Hub	(435	) \$4.06
Natural Gas	Oct -Dec 2015	Costless Collars	Henry Hub	(50	) \$ 4.00 - 4.50
Natural Gas	Oct -Dec 2015	Basis Swaps	NGPL	(20	) \$(0.18
Natural Gas	Oct -Dec 2015	Basis Swaps	Rockies	(280	) \$(0.17
Natural Gas	Oct -Dec 2015	Basis Swaps	San Juan	(108	) \$(0.11
Natural Gas	Oct -Dec 2015	Basis Swaps	SoCal	(50	) \$0.08
Natural Gas	2016	Fixed Price Swaps	Henry Hub	(412	) \$3.63
Natural Gas	2016	Swaptions	Henry Hub	(90	) \$4.23
Natural Gas	2016	Basis Swaps	NGPL	(5	) \$(0.23
Natural Gas	2016	Basis Swaps	Permian	(10	) \$(0.19
Natural Gas	2016	Basis Swaps	Rockies	(90	) \$(0.24
Natural Gas	2016	Basis Swaps	San Juan	(60	) \$(0.19
Natural Gas	2016	Basis Swaps	SoCal	(18	) \$(0.03
Natural Gas	2017	Fixed Price Swaps	Henry Hub	(93	) \$3.22
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 Calls	Henry Hub	(16	) \$4.75
Crude Oil					
Crude Oil	Oct -Dec 2015	Fixed Price Swaps	WTI	(30,146	) \$85.63
Crude Oil	Oct -Dec 2015	Basis Swaps	Midland- Cushing	(5,000	) \$0.30
Crude Oil	2016	Fixed Price Swaps	WTI	(25,049	) \$62.22
Crude Oil	2016	Basis Swaps	Midland- Cushing	(5,000	) \$(0.45
Crude Oil	2016	Swaptions	WTI	(8,500	) \$84.27
Crude Oil	2017	Fixed Price Swaps	WTI	(5,554	) \$65.30

Derivatives related to crude oil production are fixed price swaps settled on the business day average and swaptions.

The derivatives related to natural gas production are fixed price swaps, basis swaps, calls, swaptions and costless (a)collars. 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.

(b)Natural gas volumes are reported in BBTu/day and crude oil volumes are reported in Bbl/day.

(c)The weighted average price for natural gas is reported in \$/MMBtu and the crude oil price is reported in \$/Bbl.

Derivatives primarily related to transportation

The following table sets forth the derivative notional volumes of the net long (short) positions of derivatives primarily related to transportation contracts, which are included in our commodity derivatives portfolio as of September 30, 2015. The 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.

Commodity	Period	Contract Type (a)	Location (b)	Notional Volume (c)
Natural Gas	Oct -Dec 2015	Index	Multiple	(39

- (a) We enter into exchange traded fixed price and basis swaps, over-the-counter fixed price and basis swaps, physical fixed price transactions and transactions with an index component.
- (b) We transact at multiple locations primarily around our core assets to maximize the economic value of our transportation and asset management agreements.
- (c) Natural gas volumes are reported in BBtu/day.

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, 2015		December 31, 2014	
	Assets (Millions)	Liabilities	Assets	Liabilities
Derivatives related to production	\$451	\$8	\$517	\$10
Derivatives related to physical marketing agreements	3	4	19	32
Total derivatives	\$454	\$12	\$536	\$42

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 on derivative instruments. The following table presents the net gain (loss) related to our energy commodity derivatives.

	Three months ended September 30, 2015		Nine months ended September 30, 2015	
	2015	2014	2015	2014
Gain (loss) from derivatives related to production (a)	\$206	\$150	\$260	\$40
Gain (loss) from derivatives related to physical marketing agreements (b)	(1 )	(2 )	(21 )	(104 )
Net gain (loss) on derivatives not designated as hedges	\$205	\$148	\$239	\$(64 )

Includes receipts totaling \$159 million and \$10 million for settlements of derivatives during the three months ended (a) September 30, 2015 and 2014, respectively; and receipts totaling \$454 million and payments totaling \$57 million for the nine months ended September 30, 2015 and 2014, respectively.

Includes payments totaling \$4 million and receipts totaling \$5 million for settlements of derivatives during the (b) three months ended September 30, 2015 and 2014, respectively; and payments totaling \$32 million and \$114 million for the nine months ended September 30, 2015 and 2014, respectively.

The cash flow impact of our derivative activities is presented in the Consolidated Statements of Cash Flows as changes in current and noncurrent derivative assets and liabilities.

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 (Millions)	Netting Adjustments (a)	Cash Collateral Posted (Received)	Net Amount
September 30, 2015				
Derivative assets with right of offset or master netting agreements	\$454	\$(11 )	\$—	\$443
Derivative liabilities with right of offset or master netting agreements	\$(12 )	\$11	\$1	\$—
December 31, 2014				
Derivative assets with right of offset or master netting agreements	\$536	\$(25 )	\$—	\$511
Derivative liabilities with right of offset or master netting agreements	\$(42 )	\$25	\$17	\$—

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, 2015, we had collateral totaling \$1 million posted to derivative counterparties, which includes \$1 million of maintenance margin for changes in the fair value of those positions, to support the aggregate fair value of our net \$1 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of less than \$1 million to our liability balance for our own nonperformance risk. There would have been no additional collateral 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, 2015.

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.

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 2015 and 2014, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net

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

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, 2015.

Counterparty Type	Gross Total (Millions)	Net Total
Financial institutions (Investment Grade)(a)	\$455	\$444
Credit reserves	(1	) (1
Credit exposure from derivatives	\$454	\$443

(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 nine largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. 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 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 our 2014 Annual Report on Form 10-K. 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 Annual Report on Form 10-K.

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 results of RKI after August 17, 2015 included in the following discussions include \$22 million of product revenues, \$5 million of net gain on derivatives, \$12 million of depreciation, depletion and amortization and \$7 million of lease operating expenses. In addition, we incurred \$104 million of acquisition related expenses 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.

On January 29, 2015, we completed the disposition of our international interests pursuant to the successful merger of Apco Oil and Gas International Inc. ("Apco") with a subsidiary of privately held Pluspetrol Resources Corporation. The results of Apco are reported as discontinued operations.

On September 1, 2015, we completed a portion of the Powder River Basin divestiture and on October 30, 2015, we closed on the remainder of the divestiture (see Note 3 of Notes to Consolidated Financial Statements). The results of operations of the Powder River Basin are reported as discontinued operations. In connection with the exit of the Powder River Basin, we have recorded charges totaling \$187 million associated with remaining obligations of certain pipeline transportation, gathering and treating contracts. These charges are also included in discontinued operations. Unless indicated otherwise, the following discussion relates to continuing operations.

### Overview

The following table presents our production volumes and financial highlights for the three and nine months ended September 30, 2015 and 2014:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Production Sales Data(a):				
Natural gas (MMcf)	61,143	68,614	186,008	212,117
Oil (MBbls)	3,241	2,373	9,333	6,269
NGLs (MBbls)	1,958	1,574	5,267	4,786
Combined equivalent volumes (MMcfe)(b)	92,334	92,295	273,610	278,450
Per day combined equivalent volumes (MMcfe/d)	1,004	1,003	1,002	1,020
Combined equivalent volumes (MBoe)(b)	15,389	15,383	45,602	46,408
Per day combined equivalent volumes (MBoe/d)	167.3	167.2	167.0	170.0
Financial Data (millions):				
Total revenues	\$537	\$747	\$1,393	\$2,368
Operating income (loss)	\$(29)	\$102	\$32	\$(54)
Cash capital expenditures(c)	\$211	\$597	\$890	\$1,325
Capital expenditure activity(c)	\$205	\$629	\$640	\$1,389

(a) Excludes production from our discontinued operations.

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

(c) Includes capital expenditures related to discontinued operations of \$1 million and \$27 million for the three months ended September 30, 2015 and 2014, respectively, and \$19 million and \$70 million for the nine months ended September 30, 2015 and 2014, respectively.



Our third-quarter 2015 operating results were \$131 million unfavorable compared to third-quarter 2014. The primary unfavorable impacts include \$159 million lower product revenues, \$41 million higher depreciation, depletion and amortization expense, \$28 million higher exploration expenses and \$23 million of acquisition costs, partially offset by \$57 million increase in net gain (loss) on derivatives and \$52 million in total from lower operating expenses, including lease and facility operating, gathering, processing and transportation, operating taxes and general and administrative expenses for the three months ended September 30, 2015 compared to the same period in 2014.

Our year-to-date 2015 operating results were \$86 million favorable compared to year-to-date 2014. The primary favorable impacts include \$279 million net gain on sales of assets in 2015 (see Note 5 of Notes to Consolidated Financial Statements) while 2014 included a \$196 million loss on the sale of a portion of our working interests in the Piceance Basin, a \$303 million favorable change in net gain (loss) on derivatives and \$125 million in total from lower operating expenses, including lease and facility operating, gathering, processing and transportation, operating taxes and general and administrative expenses for year to date 2015 compared to 2014. Unfavorable impacts include a \$592 million decrease in product revenues, \$110 million lower net gas management margin, \$89 million higher depreciation, depletion and amortization expense and \$23 million of acquisition costs.

#### Outlook

As previously disclosed, our strategy is to simplify our geographic focus and expand returns, margins and cash flow over the next five years. Key to this strategy are the core resource plays in North Dakota, New Mexico and now Texas. During 2015, we have made significant progress toward simplifying our geographic focus with the completion of the sales of our international interests in Argentina, a significant portion of our Appalachian Basin operations and our Powder River Basin properties. As stated in the past, the market conditions may be challenging for producers but may give rise to opportunities for acquisitions in areas that would be a complimentary addition to our portfolio. Such an opportunity arose for us and in August 2015, we completed the acquisition of privately-held RKI Exploration & Production, LLC ("RKI") (the "Acquisition"). See Note 2 of Notes to Consolidated Financial Statements for further discussion. Because of this transaction and the lower commodity price environment for which the industry finds itself, we have increased our leverage and have established goals of debt reduction via asset sales for 2015 and 2016. As an example, we have signed an agreement for the sale of our gathering assets in the Williston Basin. Combined, the Powder River divestiture and the Williston gathering asset sale place us more than half of the way toward our announced goal targeting \$400 to \$500 million in divestitures by the end of this year. We also are targeting another \$400 to \$500 million in asset sales in 2016. Other portfolio rationalization opportunities include the monetization of additional midstream infrastructure, non-operated properties or other asset sales, along with evaluating creative options to unlock Piceance Basin value. These targeted divestitures will provide proceeds to delever WPX after the debt incurred for the Acquisition; however, some divestitures may result in impairments or losses on the sale. We believe the RKI Acquisition accomplishes several strategic objectives for us and is complementary to our business strategies in the following ways:

**Build Asset Scale.** The Acquisition provides an entry into the Delaware Basin, a significant resource play with multiple horizons of oil in place. The asset scale and concentrated acreage position will allow for efficient, low-cost development activities over a number of years.

**Increase Margins.** The Delaware Basin assets associated with the Acquisition contain both current oil production and undeveloped resource potential, allowing for an increase in near term cash margins, along with the potential for oil reserve and production growth in the future.

**Continue Oil Development.** The entry into a new, oil-focused basin and the incremental drilling returns associated with the Acquisition will provide additional optionality to our portfolio, providing for a more balanced commodity mix and the opportunity to allocate capital in an additional basin where expected returns are attractive compared to our other assets.

**Operational Excellence.** Our management team's history of operating large-scale resource development plays will be complemented by the addition of a proven, established operational team from RKI and the associated midstream assets that provide the necessary infrastructure to increase development operations.

While the significant declines in forward commodity prices, especially oil, is challenging to the oil and gas industry as evidenced by the reduced 2015 capital plans among our peers and reductions in workforces across the industry, we are committed to our long-term strategy. However, we will remain flexible to adjust to market conditions and rebuilding

the strength of our balance sheet. For the remainder of 2015, approximately three-fourths of our expected natural gas production and oil production are hedged at prices above the current market, which provides significant protection to price downturns in 2015. For 2016, approximately two-thirds of our expected natural gas production and oil production are hedged at prices above the current market. Our 2015 drilling activity has been greatly reduced in comparison to 2014 as we continue to either drill locations that generate the highest economic returns, preserve leases or optimize the drilling rigs already under contract in an effort to reduce the impact of rig release penalties. Additionally, as we reduce our areas of focus, we have the opportunity to improve our cost structure and ensure that our organization is in alignment with growth objectives. We will continue to focus on

lowering costs through reduced drilling times, efficient use of pad design and completion activities, and working with our vendors to lower costs on goods and services. We continue to make progress in all of these areas. We continue to review our general and administrative costs and services. During the first and second quarters of 2015, we reduced our company-wide workforce by approximately 8 percent and consolidated most of our regional office staff in Denver, Colorado, with personnel at the Company's headquarters in Tulsa, Oklahoma.

Our 2015 capital program, excluding the Acquisition, is expected to be in line with our projected cash flow. Through September 30, 2015, our 2015 capital activity totaled \$640 million, including \$205 million in the third quarter, while third-quarter cash flow from operations was \$199 million. Planned capital investments for new activity in full-year 2015 are approximately \$825 million to \$925 million and includes Permian Basin capital investment activity of \$100 million to \$120 million after the closing of the Acquisition.

For the full-year 2015, we expect to spend \$285 million to \$305 million in the Williston Basin optimizing rigs already under contract at the beginning of the year and ramped down to one rig by late spring 2016. We are currently running two rigs in the basin. Additionally, we resumed completions of previously drilled wells for which we were deferring completions. We expect to spend \$290 million to \$310 million in the Gallup Sandstone in 2015 on drilling activity which is preserving the leases and forming units.

We will be reducing our natural gas drilling effort in the Piceance Basin because of lower expected natural gas pricing in the near term. The Piceance Basin offers scale and efficiency combined with significant infrastructure already in place. We expect to spend \$150 million to \$165 million in the Piceance Basin and have moved to a one rig program during the second half of 2015. A portion of the Piceance Basin activity includes limited drilling in the Niobrara Shale that is focused on resource evaluation, driving down costs and optimizing completion techniques. The results of recently completed Niobrara wells are under review. As previously stated, we are evaluating creative options to unlock Piceance Basin value. There is a potential that such options would be less than the net book value.

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 diversify our commodity portfolio (production and reserves) through the development of our oil play 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;
- lower than expected proceeds from asset sales;
- counterparty credit and performance risk;
- general economic, financial markets or industry downturn;
- 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;
- decreased drilling success; and
- unavailability of capital.

Changes in the forward prices will be considered as we proceed with our 2015 capital program and plan for our 2016 capital program. Further, we continue to monitor the long-term market outlooks and forecasts for potential indicators of needed changes to our forecasted natural gas and oil prices. If forecasted natural gas and oil prices were to decline we would need to review the producing properties net book value for possible impairment. If impairments were required, the charges could be significant. The net book value of our predominantly natural gas proved properties is

\$3.5 billion and the net book value of our predominantly oil proved properties, excluding those recently acquired, is \$2.8 billion. See our discussion of impairment of

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long-lived assets in our critical accounting estimates discussion in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2014. 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.

#### Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. For the remainder of 2015 and 2016, we have the following contracts as of the date of this filing shown at weighted average volumes and basin-level weighted average prices:

Natural Gas	Oct - Dec 2015		2016	
	Volume (BBtu/d)	Weighted Average Price (\$/MMBtu)	Volume (BBtu/d)	Weighted Average Price (\$/MMBtu)
Fixed-price—Henry Hub	435	\$4.06	412	\$3.63
Swaptions—Henry Hub	—	\$—	90	\$4.23
Collars—Henry Hub	50	\$ 4.00 - 4.50	—	\$—
Basis swaps—NGPL	20	\$(0.18	) 5	\$(0.23 )
Basis swaps—Permian	—	\$—	25	\$(0.18 )
Basis swaps—San Juan	108	\$(0.11	) 73	\$(0.19 )
Basis swaps—Rockies	280	\$(0.17	) 163	\$(0.22 )
Basis swaps—SoCal	50	\$0.08	30	\$(0.02 )
Crude Oil	Oct - Dec 2015		2016	
	Volume (Bbls/d)	Weighted Average Price (\$/Bbl)	Volume (Bbls/d)	Weighted Average Price (\$/Bbl)
Fixed-price—WTI	30,146	\$85.63	27,549	\$61.70
Swaptions—WTI	—	\$—	11,000	\$77.95
Basis swaps—Midland	5,000	\$0.30	5,000	\$(0.45 )

## Results of Operations

Operations of our company include natural gas, oil and NGL development, production and gas management activities primarily located in Colorado, New Mexico, North Dakota and Texas. Our development and production techniques specialize in production from tight-sands and shale formations primarily in the Piceance, Williston and San Juan Basins and more recently, the Permian Basin. 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, coupled with the sale of our commodity volumes.

## Three Month-Over-Three Month Results of Operations

## Revenue Analysis

	Three months ended September 30, 2015                      2014 (Millions)		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change
Revenues:				
Natural gas sales	\$ 146	\$ 201	\$(55)	(27)%
Oil and condensate sales	124	199	(75)	(38)%
Natural gas liquid sales	24	53	(29)	(55)%
Total product revenues	294	453	(159)	(35)%
Gas management	35	145	(110)	(76)%
Net gain (loss) on derivatives	205	148	57	39%
Other	3	1	2	200%
Total revenues	\$ 537	\$ 747	\$(210)	(28)%

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:

\$55 million decrease in natural gas sales reflects \$33 million related to lower sales prices and a \$22 million decrease related to lower production sales volumes. The decrease in our production sales volumes is due in part to declines in the Piceance Basin and the impact of the sale of Appalachian Basin assets in the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements). Natural gas production from the Piceance Basin represents approximately 72 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for the three months ended September 30, 2015 and 2014:

	Three months ended September 30, 2015                      2014	
Natural gas sales (per Mcf)	\$ 2.39	\$ 2.92
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	0.91	0.15
Natural gas net price including derivative settlements (per Mcf)	\$ 3.30	\$ 3.07
Natural gas production sales volumes (MMcft)	61,143	68,614
Per day natural gas production sales volumes (MMcft/d)	665	746

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



\$75 million decrease in oil and condensate sales reflects \$130 million related to lower sales prices for the three months ended September 30, 2015 as compared to 2014, partially offset by a \$38 million increase related to higher production sales volumes and a \$17 million impact from the Permian Basin. The increase in production sales volumes primarily relates to continued development drilling in the Gallup Sandstone in the San Juan Basin. In the San Juan Basin, volumes were 10.4 MBbls per day for the three months ended September 30, 2015 compared to 3.9 MBbls per day for the same period in 2014. The following table reflects oil and condensate production prices and volumes for the three months ended September 30, 2015 and 2014:

	Three months ended September 30,	
	2015	2014
Oil sales (per barrel)	\$ 38.11	\$ 84.11
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	31.79	(0.70 )
Oil net price including derivative settlements (per barrel)	\$ 69.90	\$ 83.41
Oil and condensate production sales volumes (MBbls)	3,241	2,373
Per day oil and condensate production sales volumes (MBbls/d)	35.2	25.8

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

\$29 million decrease in natural gas liquids sales reflects \$42 million related to lower NGL sales prices partially offset by \$13 million higher production sales volumes for the three month ended September 30, 2015 compared to 2014.

The following table reflects NGL production prices and volumes for the three months ended September 30, 2015 and 2014:

	Three months ended September 30,	
	2015	2014
NGL sales (per barrel)	\$ 12.40	\$ 33.64
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	—	0.66
NGL net price including derivative settlements (per barrel)	\$ 12.40	\$ 34.30
NGL production sales volumes (MBbls)	1,958	1,574
Per day NGL production sales volumes (MBbls/d)	21.3	17.1

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

The following table summarizes the composition of the Piceance NGL barrel for the three months ended September 30, 2015 and 2014:

	Three months ended September 30,			
	2015		2014	
	% of barrel	\$/gallon	% of barrel	\$/gallon
Ethane	30	% \$0.20	29	% \$0.28
Propane	34	% \$0.41	33	% \$1.05
Iso-Butane	9	% \$0.56	9	% \$1.28
Normal Butane	8	% \$0.55	7	% \$1.25
Natural Gasoline	19	% \$0.99	22	% \$2.08

\$110 million decrease in gas management revenues primarily due to lower average prices on physical natural gas sales as well as lower natural gas sales volumes. The decrease in volumes primarily relates to the sale of a package of marketing contracts in the second quarter of 2015 and the release of certain firm transportation capacity in the first and second quarters of 2015 (see Note 5 of Notes to Consolidated Financial Statements). Most of the net gas management margin recognized in the winter months was a result of activity around these contracts and firm transportation capacity. As a result, gas management revenues, expenses and net margins in future periods will be significantly less than 2015

levels. We experienced a similar decrease of \$121 million in related gas management costs and expenses, discussed below.

\$57 million favorable change in net gain (loss) on derivatives primarily as a result of decreases in forward prices. We received cash proceeds of \$159 million and \$10 million from our derivatives for the three months ended September 30, 2015 and 2014, respectively.

Cost and operating expense and operating income (loss) analysis

	Three months ended September 30, 2015		2014		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change
Costs and expenses:						
Lease and facility operating	\$50	\$63	\$13	21		%
Gathering, processing and transportation	75	82	7	9		%
Taxes other than income	17	32	15	47		%
Gas management, including charges for unutilized pipeline capacity	43	164	121	74		%
Exploration	56	28	(28	) (100	)	%
Depreciation, depletion and amortization	242	201	(41	) (20	)	%
Net (gain) loss on sales of assets	(1	) —	1	NM		
Loss on sale of working interests in the Piceance Basin	—	1	1	100		%
General and administrative	54	71	17	24		%
Acquisition costs	23	—	(23	) NM		
Other—net	7	3	(4	) (133	)	%
Total costs and expenses	\$566	\$645	\$79	12		%
Operating income (loss)	\$(29	) \$102	\$(131	) 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 components of our costs and expenses are comprised of the following:

\$13 million decrease in lease and facility operating expenses primarily relates to lower natural gas volumes due to the sales of a portion of our Appalachian Basin assets in the first quarter of 2015 as well as cost reduction efforts in the Williston and Piceance Basins. This decrease is partially offset by higher oil production volumes and approximately \$7 million related to the Permian Basin since the Acquisition date. Lease and facility operating expense averaged \$3.27 per Boe for the three months ended September 30, 2015 compared to \$4.05 per Boe for the same period in 2014.

\$7 million decrease in gathering, processing and transportation expenses primarily related to lower natural gas volumes. Gathering, processing and transportation expenses averaged \$4.84 per Boe for the three months ended September 30, 2015 and \$5.32 per Boe for the same period in 2014.

\$15 million decrease in taxes other than income from 2015 compared to 2014 primarily relates to lower commodity prices and decreased natural gas production volumes, partially offset by higher oil production volumes. Taxes other than income averaged \$1.10 per Boe for the three months ended September 30, 2015 compared to \$2.09 per Boe for the same period in 2014.

\$121 million decrease in gas management expenses primarily due to lower average prices on physical natural gas cost of sales as well as lower natural gas purchase volumes, as previously discussed. Also included in gas management expenses are \$8 million and \$16 million for the three months ended September 30, 2015 and 2014, respectively, for unutilized pipeline capacity. Unutilized pipeline capacity expenses will be less in the future as a result of the charge included in discontinued operations (see Note 3 of Notes to Consolidated Financial Statements); however, we will continue to have cash outflows associated with these contracts.

\$28 million increase in exploration expenses primarily relates to a non-core exploratory play where we no longer intend to continue exploration activities (see Note 5 of Notes to Consolidated Financial Statements). As a result of the Acquisition and market conditions, our exploratory activities in non-core areas will be limited in the near future.

\$41 million increase in depreciation, depletion and amortization partially due to a higher rate, higher oil production volumes and approximately \$12 million related to the Permian Basin. The higher rate is due in part to the fact that we

adjusted the proved reserves used for the calculation of depletion and amortization to reflect the impact of a decrease in the 12-month average price resulting in approximately \$16 million of additional depreciation, depletion and amortization coupled with the \$5 million and \$7 million impacts from first and second quarters, respectively. Further decreases in the 12-month average price may result in additional increases in our depreciation, depletion and amortization expense. During the three months ended September 30, 2015, our depreciation, depletion and amortization averaged \$15.72 per Boe compared to an average \$13.09 per Boe for the same period in 2014. \$17 million decrease in general and administrative expenses primarily due to the absence of \$8 million of costs associated with an early exit program offered in 2014 and reduced employee and related costs as a result of headcount reductions. General and administrative expenses averaged \$3.55 per Boe for the three months ended September 30, 2015 compared to \$4.61 per Boe for the same period in 2014.

\$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,		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change
	2015	2014		
	(Millions)			
Operating income (loss)	\$ (29)	) \$ 102	\$ (131)	) NM
Interest expense	(65)	) (31)	) (34)	) (110) %
Loss on extinguishment of acquired debt	(65)	) —	(65)	) NM
Investment income and other	1	) —	1	) NM
Income (loss) from continuing operations before income taxes	(158)	) 71	(229)	) NM
Provision (benefit) for income taxes	(52)	) 25	77	) NM
Income (loss) from continuing operations	(106)	) 46	(152)	) NM
Income (loss) from discontinued operations	(124)	) 20	(144)	) NM
Net income (loss)	(230)	) 66	(296)	) NM
Less: Net income (loss) attributable to noncontrolling interests	—	) 4	(4)	) (100) %
Net income (loss) attributable to WPX Energy, Inc.	\$ (230)	) \$ 62	\$ (292)	) NM

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 \$15 million associated with the notes issued in the third quarter of 2015 and \$16 million of fees 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, including a make whole premium, relates to the satisfaction and discharge of RKI's senior notes at the time of the closing of the Acquisition (see Note 2 of Notes to Consolidated Financial Statements).

Provision (benefit) for income taxes changed favorably due to a pre-tax loss for the three months ended September 30, 2015 compared to pre-tax income for the same period in 2014. 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.

The change in income (loss) from discontinued operations was primarily due to the absence of operating results of Apco, 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 under pipeline capacity, gathering and treating agreements, partially offset by \$13 million received in third-quarter 2015 from the settlement of the escrow from a previous sales agreement for the Powder River Basin assets (see Note 3 of Notes to Consolidated Financial Statements).

## Nine Month-Over-Nine Month Results of Operations

## Revenue Analysis

	Nine months ended September 30, 2015                      2014 (Millions)		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
Revenues:					
Natural gas sales	\$440	\$780	\$(340)	(44)	)%
Oil and condensate sales	386	542	(156)	(29)	)%
Natural gas liquid sales	72	168	(96)	(57)	)%
Total product revenues	898	1,490	(592)	(40)	)%
Gas management	250	937	(687)	(73)	)%
Net gain (loss) on derivatives	239	(64)	) 303	NM	
Other	6	5	1	20	%
Total revenues	\$1,393	\$2,368	\$(975)	(41)	)%

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:

\$340 million decrease in natural gas sales is primarily due to \$244 million related to lower sales prices and \$96 million related to lower production sales volumes. The decrease in our production sales volumes is due in part to the impact of the sales of Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during second-quarter 2014. Natural gas production from the Piceance Basin represented approximately 74 percent of our total natural gas production. The following table reflects natural gas production prices and volumes for the nine months ended September 30, 2015 and 2014:

	Nine months ended September 30, 2015                      2014	
Natural gas sales (per Mcf)	\$2.37	\$3.68
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	0.99	(0.21)
Natural gas net price including derivative settlements (per Mcf)	\$3.36	\$3.47
Natural gas production sales volumes (MMcf)	186,008	212,117
Per day natural gas production sales volumes (MMcf/d)	681	777

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

\$156 million decrease in oil and condensate sales reflects \$401 million related to lower sales prices partially offset by a \$228 million increase related to higher production sales volumes for 2015 compared to 2014 and \$17 million impact from the Permian Basin. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin and the Gallup Sandstone in the San Juan Basin. In the Williston and San Juan Basins, volumes were 22.1 MBbls per day and 9.0 MBbls per day, respectively, for the first nine months of 2015 compared to 18.2 MBbls per day and 2.9 MBbls per day, respectively, for the same period in 2014. The following table reflects oil and condensate production prices and volumes for the nine months ended September 30, 2015 and 2014:

	Nine months ended September 30,	
	2015	2014
Oil sales (per barrel)	\$41.30	\$86.47
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	28.83	(2.07 )
Oil net price including derivative settlements (per barrel)	\$70.13	\$84.40
Oil and condensate production sales volumes (MBbls)	9,333	6,269
Per day oil and condensate production sales volumes (MBbls/d)	34.2	23.0

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

\$96 million decrease in natural gas liquids sales primarily reflects lower NGL prices for 2015 compared to 2014. The following table reflects NGL production prices and volumes for the nine months ended September 30, 2015 and 2014:

	Nine months ended September 30,	
	2015	2014
NGL sales (per barrel)	\$13.73	\$35.16
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	—	(0.05 )
NGL net price including derivative settlements (per barrel)	\$13.73	\$35.11
NGL production sales volumes (MBbls)	5,267	4,786
Per day NGL production sales volumes (MBbls/d)	19.3	17.5

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

The following table summarizes the composition of the Piceance NGL barrel for the nine months ended September 30, 2015 and 2014:

	Nine months ended September 30,			
	2015		2014	
	% of barrel	\$/gallon	% of barrel	\$/gallon
Ethane	31	% \$0.21	31	% \$0.29
Propane	33	% \$0.48	32	% \$1.13
Iso-Butane	9	% \$0.62	9	% \$1.33
Normal Butane	8	% \$0.62	8	% \$1.29
Natural Gasoline	19	% \$1.10	20	% \$2.13

\$687 million decrease in gas management revenues is primarily due to lower average prices on physical natural gas sales as well as lower commodity sales volumes. The decrease in volumes primarily relates to the sale of a package of marketing contracts in the second quarter of 2015 and release of certain related firm transportation capacity in the first and second quarters of 2015 (see Note 5 of Notes to Consolidated Financial Statements). The decrease in the sales

price was greater than the decrease in the purchase price as reflected in the \$577 million decrease in related gas management costs and expenses, discussed below.



\$303 million favorable change in net gain (loss) on derivatives primarily as a result of decreases in forward natural gas prices. We received cash proceeds of \$454 million and \$57 million from our derivatives for the nine months ended September 30, 2015 and 2014, respectively.

Cost and operating expense and operating income (loss) analysis

	Nine months ended September 30,		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
	2015	2014			
	(Millions)				
Costs and expenses:					
Lease and facility operating	\$ 158	\$ 182	\$ 24	13	%
Gathering, processing and transportation	217	249	32	13	%
Taxes other than income	58	100	42	42	%
Gas management, including charges for unutilized pipeline capacity	211	788	577	73	%
Exploration	69	97	28	29	%
Depreciation, depletion and amortization	685	596	(89)	(15)	) %
Net (gain) loss on sales of assets	(279)	) —	279	NM	
Loss on sale of working interests in the Piceance Basin	—	196	196	100	%
General and administrative	181	208	27	13	%
Acquisition costs	23	—	(23)	NM	)
Other—net	38	6	(32)	NM	)
Total costs and expenses	\$ 1,361	\$ 2,422	\$ 1,061	44	%
Operating income (loss)	\$ 32	\$ (54)	) \$ 86	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 components on our domestic costs and expenses are comprised of the following:

\$24 million decrease in lease and facility operating expenses primarily relates to lower natural gas volumes due to the sales of a portion of our Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during the second-quarter 2014, as well as cost reduction efforts in the Williston and Piceance Basins. This decrease is partially offset by higher oil production volumes and approximately \$7 million related to the Permian Basin since the Acquisition date. Lease and facility operating expense averaged \$3.46 per Boe for the nine months ended September 30, 2015 compared to \$3.93 per Boe for the same period in 2014.

\$32 million decrease in gathering, processing and transportation expenses primarily relates to lower natural gas volumes. Additionally, during the nine months ended September 30, 2014, we recognized approximately \$5 million related to a tariff rate refund received in prior years which was no longer under appeal by the pipeline company.

Gathering, processing and transportation charges averaged \$4.75 per Boe for 2015 and \$5.37 per Boe for 2014.

\$42 million decrease in taxes other than income primarily relates to lower commodity prices and decreased natural gas production volumes, partially offset by higher oil production volumes. Taxes other than income averaged \$1.26 per Boe for the nine months ended September 30, 2015 compared to \$2.15 per Boe for the same period in 2014.

\$577 million decrease in gas management expenses is primarily due to lower average prices on physical natural gas cost of sales as well as lower commodity purchase volumes, as previously discussed. Additionally in 2014, we recognized approximately \$11 million related to a tariff rate refund received in prior years which was no longer under appeal by the pipeline company. Also included in gas management expenses are \$27 million and \$44 million for the nine months ended September 30, 2015 and 2014, respectively, for unutilized pipeline capacity. Unutilized pipeline capacity expenses will be less in the future as a result of the charge included in discontinued operations (see Note 3 of Notes to Consolidated Financial Statements); however, we will continue to have cash outflows associated with these contracts.

\$28 million decrease in exploration expenses primarily relates to a higher total of impairments in 2014 of exploratory area leasehold and well costs in non-core exploratory plays for which management no longer intends to continue exploratory activities as compared to 2015 (see Note 5 of Notes to Consolidated Financial Statements).

\$89 million increase in depreciation, depletion and amortization is primarily due to a higher rate, higher oil production volumes and approximately \$12 million related to the Permian Basin. The higher rate is due in part to the fact that we have adjusted the proved reserves used for the calculation of depletion and amortization to reflect the impact of a decrease in the 12-month average price resulting in a \$45 million addition to depreciation, depletion and amortization. Further decreases in the 12-month average price may result in additional increases in our depreciation, depletion and amortization expense. During the nine months ended September 30, 2015, our depreciation, depletion and amortization averaged \$15.03 per Boe compared to an average \$12.85 per Boe for the same period in 2014.

\$279 million net gain on sales of assets primarily relates to the sales of a package of marketing contracts and release of certain related firm transportation capacity in the second quarter of 2015 and a portion of our Appalachian Basin assets in the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).

\$27 million decrease in general and administrative expenses is primarily due to reduced employee and related costs as a result of headcount reductions partially offset by approximately \$16 million of severance and relocation costs associated with the workforce reduction and office consolidation announced during the first quarter of 2015. General and administrative expenses averaged \$3.97 per Boe for the nine months ended September 30, 2015 compared to \$4.47 per Boe for the same period in 2014. Excluding the severance and relocation costs, general and administrative expenses would have averaged \$3.62 per Boe for 2015.

\$23 million of acquisition costs in 2015 related to the Acquisition (see Note 2 of Notes to Consolidated Financial Statements).

\$32 million increase in other expenses primarily relates 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, 2015		2014		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change
	(Millions)					
Operating income (loss)	\$32	\$(54)	)	\$86		NM
Interest expense	(130)	) (88)	)	(42)	)	(48) %
Loss on extinguishment of acquired debt	(65)	) —	)	(65)	)	NM
Investment income and other	3	) —	)	3	)	NM
Income (loss) from continuing operations before income taxes	(160)	) (142)	)	(18)	)	(13) %
Provision (benefit) for income taxes	(53)	) (44)	)	9	)	20 %
Income (loss) from continuing operations	(107)	) (98)	)	(9)	)	(9) %
Income (loss) from discontinued operations	(85)	) 50	)	(135)	)	NM
Net income (loss)	(192)	) (48)	)	(144)	)	NM
Less: Net income (loss) attributable to noncontrolling interests	1	) 7	)	(6)	)	(86) %
Net income (loss) attributable to WPX Energy, Inc.	\$(193)	) \$(55)	)	\$(138)	)	NM

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 \$15 million associated with the notes issued in the third quarter of 2015 and \$16 million of fees associated with acquisition bridge financing arrangements related to the acquisition of RKI. No borrowings were made under the acquisition bridge financing arrangements.

The loss on extinguishment of acquired debt, including a make whole premium, relates to the satisfaction and discharge of RKI's senior notes at the time of the closing of the Acquisition (see Note 2 of Notes to Consolidated Financial Statements).

Provision (benefit) for income taxes in 2015 changed favorably compared to 2014 primarily due to an unfavorable change in pre-tax loss for the nine months ended September 30, 2015 compared to 2014. 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. The provision for income taxes in 2014 reflects an additional \$9 million of deferred tax expense to accrue for the impact of new legislation enacted by the state of New York on March 31, 2014 (see Note 7 of Notes to Consolidated Financial Statements).

The change in income (loss) from discontinued operations was primarily due to the completion of the sale of Apco in first-quarter 2015 and 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 under pipeline capacity, gathering and treating agreements, partially offset by \$13 million received from the settlement of the escrow from a previous sales contract for the Powder River Basin assets for the nine months ended September 30, 2015 (see Note 3 of Notes to Consolidated Financial Statements).

## 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, 2015, 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 2015 are expected cash flows from operations, proceeds from the debt and equity offerings noted below, proceeds from monetization of assets and, if necessary, borrowings on our \$1.75 billion credit facility. We anticipate that the combination of these sources should be sufficient to allow us to pursue our business strategy and goals for 2015.

We note the following assumptions for 2015:

our planned capital expenditures, including RKI, are estimated to be approximately \$825 million to \$925 million in 2015 while cash capital expenditures are estimated to be \$1,025 million to \$1,125 million due to costs incurred in 2014 that were paid in 2015. The new spending is generally considered to be largely discretionary;

targeting to delever through \$400 million to \$500 million in asset divestitures by the end of 2015 or shortly thereafter (with similar levels targeted in 2016); and

for the remainder of 2015 we have hedged approximately three-fourths of our anticipated 2015 natural gas production at a weighted-average price of \$4.06 per MMBtu, and approximately three-fourths of anticipated 2015 oil production at a weighted-average price of \$85.63 per barrel.

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

lower than expected levels of cash flow from operations, primarily resulting from lower energy commodity prices;

lower than expected proceeds from asset sales;

higher than expected collateral obligations that may be required, including those required under new commercial agreements;

significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold; and

reduced access to our credit facility pursuant to our financial covenants.

### 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 2015. In addition, we are evaluating the level of our 2016 capital program given our expectations of our operating cash flows for 2016. Our internal and external sources of consolidated liquidity include cash generated from operations, cash and cash equivalents on hand, and our 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.

### Equity Offerings

On July 22, 2015, we completed equity offerings of (a) 30,000,000 shares of our common stock for gross proceeds of approximately \$303 million at the public offering price of \$10.10 per share and (b) \$350 million of aggregate

liquidation preference of 6.25% series A mandatory convertible preferred stock (see Note 10 of Notes to Consolidated Financial Statements).

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### Senior Notes

On July 22, 2015, we completed an offering of (i) \$500 million aggregate principal amount of the Company's 7.50% Senior Notes due 2020 (the "2020 Notes") and (ii) \$500 million aggregate principal amount of the Company's 8.25% Senior Notes due 2023 (the "2023 Notes" and together with the 2020 Notes, the "Notes"). The Notes were issued under an Indenture, dated as of September 8, 2014 (the "Base Indenture"), as supplemented by the Second Supplemental Indenture, dated as of July 22, 2015 (the "Second Supplemental Indenture"), each between the Company and The Bank of New York Mellon Trust Company, N.A., as trustee (as so supplemented, the "Indenture").

The Notes are the Company's senior unsecured obligations ranking equally with the Company's other existing and future senior unsecured indebtedness. The 2020 Notes bear interest at a rate of 7.50% per annum, and the 2023 Notes bear interest at a rate of 8.25% per annum. Interest is payable on the Notes semiannually in arrears on February 1 and August 1 of each year commencing on February 1, 2016. The 2020 Notes will mature on August 1, 2020. The 2023 Notes will mature on August 1, 2023. At any time or from time to time prior to July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, the Company may, at its option, redeem the applicable series of Notes, in whole or in part, at a make-whole redemption price as set forth in the Indenture. The Company also has the option, at any time or from time to time on or after July 1, 2020, in the case of the 2020 Notes, and June 1, 2023, in the case of the 2023 Notes, to redeem some or all of the applicable series of Notes at a redemption price equal to 100% of the principal amount of the Notes to be redeemed, as more fully described in the Indenture. The Indenture contains covenants that, among other things, restrict the Company's ability to grant liens on its assets and merge, consolidate or transfer or lease all or substantially all of its assets, subject to certain qualifications and exceptions.

### Credit Facility

We have a \$1.75 billion five-year senior unsecured revolving credit facility 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 matures on October 28, 2019. 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, 2015, we were in compliance with our financial covenants, had full access to the Credit Facility and had outstanding borrowings of \$400 million. For additional information regarding the terms of our Credit Facility, see our Annual Report on Form 10-K for the year ended December 31, 2014.

#### Amendments to Credit Facility and commitment increase

On July 16, 2015, the Company amended its Credit Facility to, among other things (a) modify the financial covenants in a manner favorable to the Company in respect of (i) the ratio of PV to Consolidated Indebtedness and (ii) the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX and (b) add a financial covenant requiring a minimum ratio of Consolidated EBITDAX to Consolidated Interest Charges (each capitalized term used herein but not defined is defined in the Company's Credit Facility, as amended).

Under the amended Credit Facility, if the Company's Corporate Rating is (a) BB- or worse by S&P and Ba3 or worse by Moody's or (b) B+ or worse by S&P or B1 or worse by Moody's, we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the Credit Facility, to Consolidated Indebtedness of at least 1.10 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and at least 1.50 to 1.00 thereafter unless and until (i) the Company's Corporate Rating is (A) BBB- or better with S&P (without negative outlook or negative watch) or (B) Baa3 or better by Moody's (without negative outlook or negative watch) and (ii) the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody's. As of the date of this filing our credit rating with S&P was BB, positive outlook and our credit rating with Moody's is Ba1, negative outlook.

In addition, the amendment increased the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX we are required to maintain to 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. Furthermore, the amendment added a financial covenant requiring us to not permit the ratio of Consolidated EBITDAX to Consolidated Interest Charges to be less than 2.50 to 1.00.

On July 31, 2015, the commitments from existing lenders were increased by \$250 million, for total commitments of \$1.75 billion. For additional information regarding activity on the Credit Facility subsequent to September 30, 2015, see Note 7 of Notes to Consolidated Financial Statements.



We have three bilateral, uncommitted letter of credit agreements which we anticipate will be renewed annually. 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. At September 30, 2015, a total of \$239 million in letters of credit have been issued.

## Sources (Uses) of Cash

	Nine months ended September 30,	
	2015	2014
	(Millions)	
Net cash provided (used) by:		
Operating activities	\$629	\$779
Investing activities	(1,259)	(939)
Financing activities	659	132
Increase (decrease) in cash and cash equivalents	\$29	\$(28)
Operating activities		

Our net cash provided by operating activities for the nine months ended September 30, 2015 decreased from the same period in 2014 primarily due to a decrease in total cash provided by operating activities related to discontinued operations. Total cash used by operating activities related to discontinued operations was approximately \$9 million for the nine months ended September 30, 2015 and total cash provided by operating activities related to discontinued operations for the nine months ended September 30, 2014 was approximately \$135 million. In addition, total cash provided by operating activities related to continuing operations decreased due to a decrease in commodity prices and natural gas volumes, substantially offset by cash received on settlement of derivative contracts and higher oil volumes. Total cash provided by operating activities for the nine months ended September 30, 2015 also includes approximately \$23 million of acquisition costs related to the Acquisition.

## Investing activities

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 yet to be remitted.

Cash capital expenditures for drilling and completion were \$774 million and \$961 million for the nine months ended September 30, 2015 and 2014, respectively. Capital expenditures incurred totaled \$640 million and \$1.4 billion during the nine months ended September 30, 2015 and 2014, respectively, including drilling and completions of \$555 million in 2015 and \$1 billion in 2014. Domestic land activities were \$37 million and \$254 million during the nine months ended September 30, 2015 and 2014, respectively. In addition, expenditures related to international were \$15 million and \$61 million for the nine months ended September 30, 2015 and 2014, respectively.

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

## 2015

- \$50 million for the portion of our Powder River Basin asset sale that closed during the third quarter of 2015, subject to post closing adjustments (see Note 3 of Notes to Consolidated Financial Statements).
- \$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).
- \$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).

## 2014

- We received approximately \$329 million for the sale of a portion of our working interests in certain Piceance Basin wells to Legacy during the second quarter of 2014 (see Note 5 of Notes to Consolidated Financial Statements).



### Financing activities

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. (see Note 10 of Notes to Consolidated Financial Statements).

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. (see Note 7 of Notes to Consolidated Financial Statements).

Cash provided by financing activities for the nine months ended September 30, 2015 also includes 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 includes 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.

During the third quarter of 2014 we issued \$500 million of senior unsecured notes at an interest rate of 5.25%. We used the proceeds from this offering to repay borrowings under our credit facility and for related transaction fees and expenses. (see Note 7 of Notes to Consolidated Financial Statements).

### Contractual Obligations

In conjunction with certain assets sales during the first half of 2015, our contractual obligations were reduced by the following:

- Approximately \$390 million in future demand payment obligations for transportation commitments (see Note 5 of Notes to Consolidated Financial Statements); and

- Approximately \$1.6 billion in liabilities associated with physical and financial derivatives in which the purchase obligation was assigned to a third party.

### Critical Accounting Estimates

As a result of the acquisition of RKI, we have the following addition to our critical accounting estimates described in Part II, Item 7 of our Annual Report on Form 10-K.

### Purchase Accounting

We periodically acquire assets and assume liabilities in transactions accounted for as business combinations, such as the RKI Acquisition. In connection with a business combination, we must allocate the fair value of consideration given to the assets acquired and liabilities assumed based on estimated fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of the acquired assets and assumed liabilities. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill. The amount of goodwill or gain on bargain purchase recorded in any particular business combination can vary significantly depending upon the values attributed to assets acquired and liabilities assumed. In addition, estimates of fair value may not be completed as of the filing date and therefore, adjustments to the purchase price allocation would be finalized in future periods, not to exceed one year from the acquisition date.

In estimating the fair values of assets acquired and liabilities assumed in a business combination, we must make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved and unproved oil and gas properties. If sufficient market data is not available regarding the fair values of proved and unproved properties, we must prepare estimates and/or engage the assistance of valuation experts. Significant judgments and assumptions are inherent in these estimates and include estimates of reserves quantities, estimates of future commodity prices (developed in consideration of market information, internal forecasts and published forward prices adjusted for locational basis differentials), drilling plans, expected capital and lease operating costs and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates.

Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional

information becomes known.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in higher depreciation, depletion and amortization expense, which results in

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lower net earnings or a higher net loss. A lower fair value assigned to property and related deferred taxes may result in the recording of goodwill. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value, or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income or increase in net loss for the period in which the impairment is recorded. See Note 2 - Acquisitions for additional information regarding purchase price allocations.

#### 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, 2015 or at December 31, 2014.

### 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 2015.

#### Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, oil 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 a net liability of less than \$1 million at September 30, 2015 and a net asset of less than \$1 million at December 31, 2014, respectively. The value at risk for contracts held for trading purposes was less than \$1 million at September 30, 2015 and December 31, 2014.

#### Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas and crude oil purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of \$442 million and \$493 million at September 30, 2015 and December 31, 2014, respectively.



The value at risk for derivative contracts held for nontrading purposes was \$23 million at September 30, 2015 and \$16 million at December 31, 2014. During the last 12 months, our value at risk for these contracts ranged from a high of \$23 million to a low of \$16 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

As previously noted, we completed our acquisition of RKI on August 17, 2015. We are analyzing RKI’s internal controls over financial reporting and are integrating them within our framework of controls. As required by the SEC, we plan to complete this process by the first anniversary of the RKI acquisition. We have implemented certain interim review and transactional controls during the third quarter that provide reasonable assurance that a material misstatement related to the RKI acquisition would be prevented or detected.

Other than described above, there have been no changes in internal controls during the third quarter of 2015 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.

We are in the process of completing the remediation of a historical impoundment in Westmoreland County, Pennsylvania under the guidance and oversight of the Pennsylvania Department of Environmental Protection. The impoundment historically held treated water from a licensed water recycler, and has allegedly affected surrounding water wells above their pre-drill water quality results, even though most of the constituents present in the surrounding wells meet state secondary drinking water standards. We have installed appropriate treatment systems to ensure that the water quality from the wells meets pre-drill standards while the remediation is completed. We believe it is likely that we will be subject to a fine in excess of \$100,000 in connection with this matter.

### Item 1A. Risk Factors

#### Risk Factors Relating to the Acquisition

We may be unable to successfully integrate RKI's operations or to realize targeted cost savings, revenues or other benefits of the Acquisition.

We believe that the Acquisition will be beneficial to us. Achieving the targeted benefits of the Acquisition will depend in part upon whether we can integrate RKI's businesses in an efficient and effective manner. We may not be able to accomplish this integration process smoothly or successfully. The successful acquisition of producing properties, including those acquired from RKI, requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas and oil prices and their appropriate differentials;
- availability and cost of transportation of production to markets;
- availability and cost of drilling equipment and of skilled personnel;
- development and operating costs and potential environmental and other liabilities;
- regulatory, permitting and similar matters; and
- our ability to obtain external financing to fund the purchase price.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we have performed a review of the subject properties that we believe to be generally consistent with industry practices. Our review may not reveal all existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections will not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. As is the case with the Acquisition, we are often not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis, and, as is the case with certain liabilities associated with the assets to be acquired, we are entitled to indemnification for only certain environmental liabilities. The integration process may be subject to delays or changed circumstances, and we can give no assurance that the acquired properties will perform in accordance with our expectations or that our expectations with respect to integration or cost savings as a result of the Acquisition will materialize.

Significant acquisitions, including the Acquisition, and other strategic transactions may involve other risks that may cause our business to suffer, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of ours while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate assets;
- the challenge of attracting and retaining personnel associated with acquired operations; and
- the failure to realize the full benefit that we expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition, or to realize these benefits within the expected time frame.





We will incur significant transaction and acquisition-related costs in connection with the Acquisition. We expect to incur significant costs associated with the Acquisition and combining the operations of the two companies, including costs to achieve targeted cost-savings. The substantial majority of the expenses resulting from the Acquisition will be composed of transaction costs related to the Acquisition, systems consolidation costs, and business integration and employment-related costs, including costs for severance, retention and other restructuring. We may also incur transaction fees and costs related to formulating integration plans. Additional unanticipated costs may be incurred in the integration of the two companies' businesses. Although we expect that the elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, should allow us to offset incremental transaction and acquisition-related costs over time, this net benefit may not be achieved in the near term, or at all.

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 2014, 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, 2015.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Except for the issuance of 40 million shares of common stock issued in connection with the Acquisition, as more fully described in our Current Report on Form 8-K filed on August 17, 2015, there were no unregistered sales of our securities for the period covered by this report.

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	Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company, LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
2.2**	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)
2.3**	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)
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	

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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 Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on January 6, 2012)

10.5 Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011)

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Exhibit No.	Description
10.6#	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
10.7	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)
10.8	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)
10.9	First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011)
10.10	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)
10.11	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)
10.12	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)
10.13	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)
10.14	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)
10.15	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)
10.16	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)
10.17	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)

- 10.18 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)
- 10.19 Agreement, dated December 17, 2013, between WPX Energy, Inc. and Taconic Capital Advisors L.P. (incorporated herein by reference to Exhibit 99.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 18, 2013)
- 10.20 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)
- 10.21 Severance Agreement, dated February 18, 2014, between WPX Energy, Inc. and Neal A. Buck (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 19, 2014) (1)

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Exhibit No.	Description
10.22	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)
10.23	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)
10.24	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)
10.25	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)
10.26	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)
10.27	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)
10.28	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)
10.29	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)
10.30	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)
10.31	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)
10.32	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)
10.33	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,

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Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)

- 10.34 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)
- 10.35\* Registration Rights Agreement dated August 17, 2015, among WPX Energy, Inc. and the signatures thereto
- 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



Exhibit No.	Description
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

- # Certain portions have been omitted pursuant to an Order Granting Confidential Treatment issued by the SEC on December 5, 2011. Omitted information has been filed separately with the SEC.
- \* 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 5, 2015