WPX ENERGY, INC.
Form 10-Q
November 07, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)

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

For the quarterly period ended September 30, 2013
OR

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

For the transition period from to
Commission file number 1-35322
WPX Energy, Inc.
(Exact Name of Registrant as Specified in Its Charter)

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange

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 ý 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 ý 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 ý	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 ý

The number of shares outstanding of the registrant's common stock at November 6, 2013 were 200,808,558.

WPX Energy, Inc.
Index

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, crude oil, and natural gas liquids (“NGL”) 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; 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 I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2012.

WPX Energy, Inc.
Consolidated Balance Sheets
(Unaudited)

	September 30, 2013	December 31, 2012
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$108	$153
Accounts receivable, net of allowance of $8 million at September 30, 2013 and $11 million at December 31, 2012	390	443
Deferred income taxes	33	17
Derivative assets	44	58
Inventories	74	66
Other	45	35
Total current assets	694	772
Investments	161	145
Properties and equipment (successful efforts method of accounting)	14,115	13,339
Less—accumulated depreciation, depletion and amortization	(5,580)	(4,923)
Properties and equipment, net	8,535	8,416
Derivative assets	13	2
Other noncurrent assets	120	121
Total assets	$9,523	$9,456
Liabilities and Equity		
Current liabilities:		
Accounts payable	$518	$509
Accrued and other current liabilities	180	203
Deferred income taxes	—	—
Derivative liabilities	28	14
Total current liabilities	726	726
Deferred income taxes	1,348	1,401
Long-term debt	1,776	1,508
Derivative liabilities	7	1
Asset retirement obligations	355	316
Other noncurrent liabilities	126	133
Contingent liabilities and commitments (Note 8)		
Equity:		
Stockholders' equity:		
Preferred stock (100 million shares authorized at $0.01 par value; no shares issued)	—	—
Common stock (2 billion shares authorized at $0.01 par value; 200.7 million shares issued at September 30, 2013 and 199.3 million shares issued at December 31, 2012)	2	2
Additional paid-in-capital	5,508	5,487
Accumulated deficit	(435)	(223)
Accumulated other comprehensive income (loss)	(1)	2
Total stockholders' equity	5,074	5,268
Noncontrolling interests in consolidated subsidiaries	111	103
Total equity	5,185	5,371
Total liabilities and equity	$9,523	$9,456

See accompanying notes.

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

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions, except per-share amounts)			
Revenues:				
Product revenues:				
Natural gas sales	$252	$331	$835	$1,000
Oil and condensate sales	183	118	473	346
Natural gas liquid sales	57	65	169	236
Total product revenues	492	514	1,477	1,582
Gas management	176	186	642	710
Net gain (loss) on derivatives not designated as hedges (Note 10)	(15)	(22)	(31)	63
Other	5	(1)	16	7
Total revenues	658	677	2,104	2,362
Costs and expenses:				
Lease and facility operating	82	68	230	202
Gathering, processing and transportation	106	124	324	379
Taxes other than income	36	23	107	78
Gas management, including charges for unutilized pipeline capacity	201	200	666	749
Exploration	21	22	60	60
Depreciation, depletion and amortization	241	243	699	719
Impairment of costs of acquired unproved reserves (Note 4)	19	—	19	117
General and administrative	68	67	214	206
Other—net	10	5	18	8
Total costs and expenses	784	752	2,337	2,518
Operating income (loss)	(126)	(75)	(233)	(156)
Interest expense	(28)	(25)	(82)	(77)
Interest capitalized	2	2	4	7
Investment income and other	4	7	20	25
Income (loss) from continuing operations before income taxes	(148)	(91)	(291)	(201)
Provision (benefit) for income taxes	(32)	(28)	(84)	(71)
Income (loss) from continuing operations	(116)	(63)	(207)	(130)
Income (loss) from discontinued operations	—	2	—	23
Net income (loss)	(116)	(61)	(207)	(107)
Less: Net income (loss) attributable to noncontrolling interests	(2)	3	5	10
Net income (loss) attributable to WPX Energy	$(114)	$(64)	$(212)	$(117)
Amounts attributable to WPX Energy, Inc.:				
Basic and diluted earnings (loss) per common share (Note 3):				
Income (loss) from continuing operations	$(0.57)	$(0.33)	$(1.06)	$(0.70)
Income (loss) from discontinued operations	—	0.01	—	0.11
Net income (loss)	$(0.57)	$(0.32)	$(1.06)	$(0.59)
Weighted-average shares (millions)	200.7	199.1	200.3	198.7

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Comprehensive Income (Loss)
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Net income (loss) attributable to WPX Energy	$(114)	$(64)	$(212)	$(117)
Other comprehensive income (loss):				
Change in fair value of cash flow hedges, net of tax (a)	$—	$(12)	$—	$56
Net reclassifications into earnings of net cash flow hedge realized gains, net of tax (b)	—	(69)	(3)	(220)
Other comprehensive income (loss), net of tax	—	(81)	(3)	(164)
Comprehensive income (loss) attributable to WPX Energy	$(114)	$(145)	$(215)	$(281)

____

(a) Change in fair value of cash flow hedges is net of income tax of $7 million for the three months ended September 30, 2012 and $32 million for the nine months ended September 30, 2012. The nine months ended September 30, 2012, includes a $15 million before tax unrealized gain that was recognized in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations, as the underlying transaction was no longer probable of occurring (see Note 10).

(b) Net reclassifications into earnings of net cash flow hedge realized gains are net of $41 million of income tax for the three months ended September 30, 2012 and $2 million and $128 million for the nine months ended September 30, 2013 and 2012, respectively. Before tax amounts realized and reclassified to product revenues, primarily natural gas sales revenues, on the Consolidated Statements of Operations were $110 million for the three months ended September 30, 2012 and $5 million and $348 million for the nine months ended September 30, 2013 and 2012, respectively.

See accompanying notes.

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

	WPX Energy, Inc., Stockholders						
	Common Stock	Additional Paid-In-Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests in Consolidated Subsidiaries(a)	Total Equity
	(Millions)						
Balance at December 31, 2012	$2	$5,487	$ (223)	$ 2	$ 5,268	$ 103	$5,371
Comprehensive income (loss):							
Net income (loss)	—	—	(212)	—	(212)	5	(207)
Other comprehensive loss	—	—	—	(3)	(3)	—	(3)
Comprehensive income (loss)							(210)
Stock based compensation	—	21	—	—	21	—	21
Contribution from noncontrolling interest					—	3	3
Balance at September 30, 2013	$2	$5,508	$ (435)	$ (1)	$ 5,074	$ 111	$5,185

____

(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,	
	2013	2012
	(Millions)	
Operating Activities		
Net income (loss)	$(207)	$(107)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	699	727
Deferred income tax provision (benefit)	(67)	(90)
Provision for impairment of properties and equipment (including certain exploration expenses)	64	160
Amortization of stock-based awards	24	22
Gain on sale of assets	(5)	(42)
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	55	128
Inventories	(5)	2
Margin deposits and customer margin deposit payable	(2)	(5)
Other current assets	(11)	9
Accounts payable	(5)	(142)
Accrued and other current liabilities	(32)	(20)
Changes in current and noncurrent derivative assets and liabilities	18	(28)
Other, including changes in other noncurrent assets and liabilities	(8)	(25)
Net cash provided by operating activities	518	589
Investing Activities		
Capital expenditures (a)	(843)	(1,165)
Proceeds from sale of assets	10	310
Purchases of investments	(3)	(2)
Other	—	3
Net cash used in investing activities	(836)	(854)
Financing Activities		
Proceeds from common stock	4	2
Proceeds from long-term debt	—	6
Borrowings on credit facility	605	—
Payments on credit facility	(335)	—
Other	(1)	(29)
Net cash provided by (used in) financing activities	273	(21)
Net increase (decrease) in cash and cash equivalents	(45)	(286)
Cash and cash equivalents at beginning of period	153	526
Cash and cash equivalents at end of period	$108	$240

(a) Increase to properties and equipment	$(864)	$(1,073)
Changes in related accounts payable	21	(92)
Capital expenditures	$(843)	$(1,165)

See accompanying notes.

8

WPX Energy, Inc.

Notes to Consolidated Financial Statements

Note 1. General, Description of Business and Basis of Presentation

General

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, 2012 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, 2013, results of operations for the three and nine months ended September 30, 2013 and 2012, changes in equity for the nine months ended September 30, 2013 and cash flows for the nine months ended September 30, 2013 and 2012.

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.

Description of Business

Operations of our company are located in the United States and South America and are organized into domestic and international reportable segments.

Domestic includes natural gas, oil and natural gas liquids ("NGL") development, production and gas management activities located in Colorado, New Mexico, North Dakota, Pennsylvania and Wyoming in the United States. We specialize in development and production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Williston, Appalachian and Green River Basins. 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, storage and related derivatives coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco Oil and Gas International Inc. (“Apco”, NASDAQ listed: APAGF), an oil and gas exploration and production company with activities in Argentina and Colombia.

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

Discontinued operations

During the second quarter of 2012, we completed the sale of our holdings in the Barnett Shale and the Arkoma Basin. The results of operations in 2012 for these holdings are reported as discontinued operations (see Note 2).

Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations.

Recently Issued Accounting Standards

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation Is Fixed at the Reporting Date ("ASU 2013-04"). The amendments in ASU 2013-04 provide guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements from which the total amount of the obligation within the scope of this guidance is fixed at the reporting date. ASU 2013-04 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The Company is currently evaluating the impact of ASU 2013-04, but we do not anticipate a material impact to the Company's financial position, results of operations or cash flows as a result of applying this ASU.

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

Recently Adopted Provisions of U.S. GAAP
In accordance with U.S. GAAP, the following provisions, which had no material impact on the Company's financial position, results of operations or cash flows, were effective as of January 1, 2013:

- The requirement to provide disclosures related to offsetting assets and liabilities, specifically as it relates to offsetting disclosures, wherein an entity must now make separate disclosures regarding the gross assets and liabilities, the offsetting amounts and the net assets and liabilities (see Note 10).
- The requirement to present significant amounts reclassified out of Accumulated Other Comprehensive Income (Loss) ("AOCI") by the respective line items in the results of operations. See Note 10 and the Consolidated Statements of Comprehensive Income (Loss).

Note 2. Discontinued Operations
Summarized Results of Discontinued Operations in 2012

	Three months ended September 30, 2012	Nine months ended September 30, 2012
	(Millions)	
Revenues	$(1)	$25
Income (loss) from discontinued operations before gain on sale and income taxes	$(1)	$(2)
Gain on sale	4	39
Provision for income taxes	(1)	(14)
Income (loss) from discontinued operations	$2	$23

Note 3. Earnings (Loss) Per Common Share from Continuing Operations
The following table summarizes the calculation of earnings per share.

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions, except per-share amounts)			
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$(114)	$(66)	$(212)	$(140)
Basic weighted-average shares	200.7	199.1	200.3	198.7
Diluted weighted-average shares (a)	200.7	199.1	200.3	198.7
Earnings (loss) per common share from continuing operations:				
Basic	$(0.57)	$(0.33)	$(1.06)	$(0.70)
Diluted	$(0.57)	$(0.33)	$(1.06)	$(0.70)

____

(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.

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Weighted-average nonvested restricted stock units and awards	2.7	1.7	2.3	1.9
Weighted-average stock options	1.2	0.9	1.1	1.1

10

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

The table below includes information related to stock options that were outstanding at September 30, 2013 and 2012 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,	
	2013	2012
Options excluded (millions)	0.4	1.8
Weighted-average exercise price of options excluded	$20.23	$17.50
Exercise price range of options excluded	$19.95 - $20.97	$15.67 - $20.97
Third quarter weighted-average market price	$19.23	$15.56

Note 4. Impairments and Exploration Expenses

Impairment of cost of acquired unproved reserves

As a result of declines in forward natural gas prices during third-quarter 2013 as compared to prior periods, we performed impairment assessments of our capitalized cost of acquired unproved reserves. Accordingly, we recorded a $19 million impairment of capitalized costs of acquired unproved reserves in the Kokopelli area of the Piceance Basin in the third quarter of 2013.

Additionally, as a result of declines in forward natural gas prices during 2012 as compared to forward natural gas prices as of December 31, 2011, we recorded $52 million and $65 million in impairments of capitalized costs of acquired unproved reserves primarily in the Powder River Basin in the first and second quarters of 2012, respectively. Our impairment analysis included an assessment of discounted future cash flows, which considered information obtained from drilling, other activities and oil and gas reserve quantities (see Note 9).

Exploration Expenses

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Geologic and geophysical costs	$6	$5	$15	$17
Dry hole costs	—	2	2	3
Unproved leasehold property impairment, amortization and expiration	15	15	43	40
Total exploration expenses	$21	$22	$60	$60

Note 5. Inventories

	September 30, 2013	December 31, 2012
	(Millions)	
Natural gas in underground storage	$13	$24
Crude oil production in transit	9	—
Material, supplies and other	52	42
	$74	$66

Due to lower natural gas prices, we recognized a lower of cost or market adjustment to natural gas in underground storage of $1 million at September 30, 2013. This adjustment is reflected in gas management expense on the Consolidated Statements of Operations for the three and nine months ended September 30, 2013.

During the first quarter of 2013, we terminated two of three storage capacity agreements and sold the related natural gas.

During 2013, we executed new rail and pipeline transportation agreements to move crude oil production to additional downstream sales markets. Portions of these production volumes, which remained in-transit and did not reach their final sales location at the end of third-quarter 2013, were recognized as crude oil production in transit inventory.

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

Note 6. Debt and Banking Arrangements
As of the indicated dates, our debt consisted of the following:

	September 30, 2013	December 31, 2012
	(Millions)	
5.250% Senior Notes due 2017	$400	$400
6.000% Senior Notes due 2022	1,100	1,100
Credit facility agreement	270	—
Apco	8	8
Other	2	2
Total debt	$1,780	$1,510
Less: Current portion of long-term debt	4	2
Total long-term debt	$1,776	$1,508

We have a $1.5 billion five-year senior unsecured revolving credit facility agreement (the "Credit Facility Agreement") that expires in 2016. Under the terms of the Credit Facility Agreement and subject to certain requirements, we may request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. As of September 30, 2013, the variable interest rate was 2.06 percent on the $270 million outstanding under the Credit Facility Agreement. Subsequent to September 30, 2013, we have borrowed an additional $60 million under the Credit Facility Agreement.

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 Agreement. At September 30, 2013, a total of $350 million in letters of credit have been issued.

Note 7. Provision (Benefit) for Income Taxes
The provision (benefit) for income taxes from continuing operations includes:

	Three months ended September 30, 2013	Three months ended September 30, 2012	Nine months ended September 30, 2013	Nine months ended September 30, 2012
	(Millions)			
Current:				
Federal	$(31)	$3	$(28)	$22
State	—	—	—	—
Foreign	3	4	11	12
	(28)	7	(17)	34
Deferred:				
Federal	(30)	(30)	(89)	(96)
State	13	(5)	8	(9)
Foreign	13	—	14	—
	(4)	(35)	(67)	(105)
Total provision (benefit)	$(32)	$(28)	$(84)	$(71)

In September 2013, the Argentine government enacted tax reform legislation related to dividends and capital gains which will apply to the Argentine operations of our consolidated investment in Apco, a Cayman Islands corporation. The new 10 percent dividend tax will be accrued by Apco when dividends are paid by its Argentine investments in future periods. The capital gains tax applies to the sale of Argentine securities by a non Argentine resident, such as Apco, making such sales subject to an effective 13.5 percent tax on the gross proceeds. As a result, Apco recorded approximately $14 million of a foreign deferred tax expense during third quarter 2013 for the excess book basis over tax basis in its equity investment in Petrolera Entre Lomas S.A., of which approximately $12 million relates to basis differences that occurred prior to 2013. This accrual

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

was partially offset by approximately $4 million of U.S. deferred tax benefit recorded by WPX related to the additional Argentine tax.

The effective income tax rate of the total benefit for the three and nine months ended September 30, 2013, is less than the federal statutory rate due primarily to taxes on foreign operations and state income taxes. State income taxes include a $9 million deferred tax provision related to an increase in a valuation allowance for certain state deferred tax assets.

The effective income tax rate of the total benefit for the three months ended September 30, 2012, is less than the federal statutory rate due primarily to taxes on foreign operations and an adjustment to the minimum tax credit that was allocated to us by our former parent, The Williams Companies ("Williams") as part of the separation from Williams, partially offset by state income taxes.

The effective income tax rate of the total benefit for the nine months ended September 30, 2012, is greater than the federal statutory rate due primarily to state income taxes, partially offset by taxes on foreign operations and an adjustment to the minimum tax credit that was allocated to us by Williams as part of the separation from Williams.

As of September 30, 2013, 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 associated with domestic or international matters will result in a significant increase or decrease of our unrecognized tax benefit.

Note 8. 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 to be tried was 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. The court has 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 enhancement test must be applied on a monthly basis in order to determine the reasonableness of post-production transportation costs. We are currently scheduled for trial in late 2013 on the issue of whether we have met that burden. Plaintiffs have claimed damages of approximately $20 million plus interest for the period from July 2000 to July 2008. However, we believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law.

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, fraud, fraud 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 seek monetary damages and a declaratory judgment enjoining activities relating to production, payments and future reporting. This matter has been removed to the United States District Court for New Mexico. 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, 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.

In February 2013, a potential class of royalty owners filed suit in Campbell County District Court, Wyoming, alleging violations of the Wyoming Royalty Payment Act by failing to properly and timely pay and report royalty and overriding royalty. Plaintiffs seek monetary damages, interest and penalties, and declaratory and injunctive relief. The case has been removed to Federal Court. As a result of recent analysis and related developments, we do not expect that our future exposure to this matter will be material.

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 other states 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 2006 through September 2013, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $103 million.

Environmental matters

The Environmental Protection Agency ("EPA"), other federal agencies, and various state regulatory agencies routinely promulgate and propose new rules, and issue updated guidance to existing rules. These new rules and rulemakings include, but are not limited to, rules for reciprocating internal combustion engine maximum achievable control technology, new air quality standards for ground level ozone, 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.

Matters related to Williams' former power business

In connection with the Separation and Distribution Agreement, Williams is obligated to indemnify and hold us harmless from any losses arising out of liabilities assumed by us, and we are obligated to pay Williams any net proceeds realized from, the pending or threatened litigation described below relating to the 2000-2001 California energy crisis and the reporting of certain natural gas-related information to trade publications.

California energy crisis

Our former power business was engaged in power marketing in various geographic areas, including California. Prices charged for power by us and other traders and generators in California and other western states in 2000 and 2001 were challenged in various proceedings, including those before the Federal Energy Regulatory Commission ("FERC"). We have entered into settlements with the State of California ("State Settlement"), major California utilities ("Utilities Settlement") and others that substantially resolved each of these issues with these parties.

Although the State Settlement and Utilities Settlement resolved a significant portion of the refund issues among the settling parties, we continue to have potential refund exposure to nonsettling parties, including various California end users that did not participate in the Utilities Settlement. We currently have a settlement agreement in principle with certain California utilities aimed at eliminating and substantially reducing this exposure. Once finalized, the settlement agreement will also resolve our collection of accrued interest from counterparties as well as our payment of accrued interest on refund amounts. Thus, as currently contemplated by the parties, the settlement agreement will resolve most, if not all, of our legal issues arising from the 2000-2001 California energy crisis. With respect to these matters, amounts accrued are not material to our financial position.

Certain other issues also remain open at the FERC and for other nonsettling parties.

Reporting of 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 have 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 on the Western States Antitrust Litigation. The panel held that the Natural Gas Act does not preempt the plaintiffs' state antitrust claims, reversing the summary judgment entered in favor of the defendants. The panel further held that the district court did not abuse its discretion in denying the plaintiffs' motions for leave to amend complaints. Defendants' filed a petition for writ of certiorari with the U.S. Supreme Court. 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, 2013, 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 have 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, 2013 and December 31, 2012, the Company had accrued approximately $24 million and $18 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 9. 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 and restricted cash approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	September 30, 2013				December 31, 2012			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$17	$39	$1	$57	$20	$38	$2	$60
Energy derivative liabilities	$12	$21	$2	$35	$11	$1	$3	$15
Long-term debt (a)	$—	$1,809	$—	$1,809	$—	$1,617	$—	$1,617

____

(a) The carrying value of long-term debt, excluding capital leases, was $1,776 million and $1,508 million as of September 30, 2013 and December 31, 2012, 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 and option 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 is relatively short with 97 percent of the net fair value of our derivatives portfolio expiring at the end of 2014. 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 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 included in Level 3 at September 30, 2013, 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, 2013 and 2012.

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

The following table presents a reconciliation of changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)			
Beginning balance	$(1)	$—	$(1)	$1
Realized and unrealized gain (loss):				
Included in income (loss) from continuing operations	(2)	—	(2)	3
Purchases, issuances, and settlements	2	—	2	(4)
Ending balance	$(1)	$—	$(1)	$—
Unrealized gain (loss) included in income (loss) from continuing operations relating to instruments still held at September 30	$(1)	$(1)	$(1)	$—

Realized and unrealized gain (loss) included in income (loss) from continuing operations for the above periods are reported in revenues in our Consolidated Statements of Operations.
The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Total losses for the nine months ended September 30,	
	2013	2012
	(Millions)	
Impairments:		
Costs of acquired unproved reserves (see Note 4) (a)	$19	$117

(a) Due to significant declines in forward natural gas prices, we assessed the carrying value of our natural gas costs of acquired unproved reserves for impairments. The impairment in 2013 is related to costs of acquired unproved reserves in the Kokopelli area of the Piceance Basin. Most of the impairment charge in 2012 is related to costs of acquired unproved reserves in the Powder River Basin. Our assessment utilized estimates of future discounted cash flows. Significant judgments and assumptions in these assessments include estimates of probable and possible reserve quantities, estimates of future natural gas prices using a forward NYMEX curve adjusted for locational basis differentials, future natural gas liquids prices, expectation for market participant drilling plans, expected capital costs and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.

Note 10. 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. Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we entered into commodity derivative contracts that continued to serve as economic hedges but were not designated as cash flow hedges for accounting purposes as we elected not to utilize this method of accounting on new derivatives instruments. Remaining commodity derivatives recorded at December 31, 2011 that were designated as cash flow hedges were fully realized by the end of the first quarter of 2013.

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 options, a combination of options that comprise a net purchased option or a zero- cost collar or swaptions.
We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity 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

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

associated with these contracts. Derivatives for transportation and storage contracts economically hedge the expected cash flows generated by those agreements.
The following table sets forth the derivative volumes that are economic hedges of production volumes as well as the notional amounts of the net long (short) positions which do not represent economic hedges of our production, both which are included in our commodity derivatives portfolio as of September 30, 2013.

Derivatives related to production

Commodity	Period	Contract Type(a)	Location	Notional Volume (b)	Weighted Average Price(c)
Crude Oil	Oct-Dec 2013	Fixed Price Swaps	WTI	(8,500)	$ 100.70
Crude Oil	Oct-Dec 2013	Fixed Price Swaps	LLS	(2,500)	$ 106.87
Natural Gas	Oct-Dec 2013	Fixed Price Swaps	Henry Hub	(470)	$ 3.59
Natural Gas	Oct-Dec 2013	Basis Swaps	Northeast	(60)	$ 0.19
Natural Gas	Oct-Dec 2013	Basis Swaps	Mid-Con	(20)	$ (0.16)
Natural Gas	Oct-Dec 2013	Basis Swaps	Rockies	(20)	$ (0.15)
NGL Propane	Oct-Dec 2013	Fixed Price Swaps	Mont Belvieu	(815)	$ 1.165
NGL Natural Gasoline	Oct-Dec 2013	Fixed Price Swaps	Mont Belvieu	(815)	$ 2.265
Crude Oil	2014	Fixed Price Swaps	WTI	(11,250)	$ 94.55
Natural Gas	2014	Fixed Price Swaps	Henry Hub	(40)	$ 4.35
Natural Gas	2014	Swaptions	Henry Hub	(40)	$ 4.35
Natural Gas	2014	Costless Collars	Henry Hub	(145)	$ 4.00 - 4.66
Natural Gas	2014	Basis Swaps	Northeast	(21)	$ (0.62)
Crude Oil	2015	Swaptions	WTI	(1,750)	$ 98.54

Derivatives primarily related to storage and transportation

Commodity	Period	Contract Type(d)	Location(e)	Notional Volume (b)	Weighted Average Price(f)
Natural Gas	Oct-Dec 2013	Fixed Price Swaps	Multiple	13	—
Natural Gas	Oct-Dec 2013	Basis Swaps	Multiple	5	—
Natural Gas	Oct-Dec 2013	Index	Multiple	(127)	—
Natural Gas	2014	Fixed Price Swaps	Multiple	(11)	—
Natural Gas	2014	Basis Swaps	Multiple	(6)	—
Natural Gas	2014	Index	Multiple	(87)	—
Natural Gas	2015	Index	Multiple	(41)	—
Natural Gas	2016	Index	Multiple	2	—
Natural Gas	2017	Index	Multiple	2	—

(a) Derivatives related to crude oil production are business day average swaps and the derivatives related to natural gas production are fixed price swaps, basis swaps, swaptions and costless 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, crude oil volumes are reported in Bbl/day, and natural gas liquids are reported in Bbl/day.

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

(d) WPX Marketing enters 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.

(e) WPX Marketing transacts at multiple locations primarily around our core assets to maximize the economic value of our transportation, storage and asset management agreements.

(f) 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.

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, 2013		December 31, 2012	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production designated as hedging instruments	$—	$—	$5	$—
Not designated as hedging instruments:				
Derivatives related to production not designated as hedging instruments	39	21	33	—
Legacy natural gas contracts from former power business	—	—	2	2
All other	18	14	20	13
Total derivatives not designated as hedging instruments	57	35	55	15
Total derivatives	$57	$35	$60	$15

The following table presents pre-tax gains and losses for our energy commodity derivatives designated as cash flow hedges, as recognized in AOCI or revenues.

	Three months ended September 30,		Nine months ended September 30,		
	2013	2012	2013	2012	Classification
	(Millions)		(Millions)		
Net gain (loss) recognized in other comprehensive income (loss) (effective portion)	$—	$(19)	$—	$88	AOCI
Net gain reclassified from accumulated other comprehensive income (loss) into income (effective portion) (a)	$—	$110	$5	$348	Revenues

(a) Gains reclassified from accumulated other comprehensive income (loss) primarily represent realized gains on derivatives designated as hedges of our production and are reflected in natural gas sales and oil and condensate sales.

There were no gains or losses recognized in income as a result of excluding amounts from the assessment of hedge effectiveness.

The following table presents pre-tax gains and losses recognized in revenues for our energy commodity derivatives not designated as hedging instruments.

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
	(Millions)		(Millions)	
Unrealized gain (loss)	$(13)	$(31)	$(18)	$28

Realized gain (loss)	(2)	9	(13)	35
Net gain (loss)	$(15)	$(22)	$(31)	$63

The cash flow impact of our unrealized gain (loss) on 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.

September 30, 2013	Gross Amount Presented on Balance Sheet (Millions)	Netting Adjustments (a)	Cash Collateral Posted(Received)	Net Amount
Derivative assets with right of offset or master netting agreements	$57	$(29)	$ —	$28
Derivative liabilities with right of offset or master netting agreements	$(35)	$29	$ —	$(6)
December 31, 2012				
Derivative assets with right of offset or master netting agreements	$60	$(10)	$ (2)	$48
Derivative liabilities with right of offset or master netting agreements	$(15)	$10	$ —	$(5)

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

Credit-risk-related features

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

As of September 30, 2013, we had a net $6 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. The 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, was $6 million.

Cash flow hedges

Changes in the fair value of our cash flow hedges, to the extent effective, are deferred in AOCI and reclassified into earnings in the same period or periods in which the hedged forecasted purchases or sales affect earnings, or when it is probable that the hedged forecasted transaction will not occur by the end of the originally specified time period. During the first quarter of 2012, approximately $15 million of unrealized gains were recognized into earnings in 2012 for hedge transactions where the underlying transactions were no longer probable of occurring due to the sale of our Barnett Shale properties. The $15 million gain is included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations for 2012. As of September 30, 2013, no derivatives were designated as cash flow hedges.

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.

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

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 2013 and 2012, we did not incur any significant losses due to counterparty bankruptcy filings. We assess our credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. We offset our credit exposure to each counterparty with amounts we owe the counterparty under derivative contracts.

The gross and net credit exposure from our derivative contracts as of September 30, 2013, is summarized as follows:

Counterparty Type	Gross Investment Grade (a) (Millions)	Gross Total	Net Investment Grade (a)	Net Total
Energy marketers and traders and other	$—	$—	$—	$—
Financial institutions	57	57	28	28
	$57	57	$28	28
Credit reserves		—		—
Credit exposure from derivatives		$57		$28

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

Our four largest net counterparty positions represent approximately 95 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, we, nor the participating financial institutions, are required to provide collateral support related to hedging activities.

At September 30, 2013, we did not hold any collateral support, either in the form of cash or letters of credit, related to our other derivative positions.

Note 11. Segment Disclosures

Our reporting segments are domestic and international (see Note 1).

Our segment presentation is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions. Domestic and international maintain separate capital and cash management structures. These factors, coupled with differences in the business environment associated with operating in different countries, serve to differentiate the management of this entity as a whole.

Performance Measurement

We evaluate performance based upon segment revenues and segment operating income (loss). There are no intersegment sales between domestic and international.

The following tables reflect the reconciliation of segment revenues and segment operating income (loss) to revenues and operating income (loss) as reported in the Consolidated Statements of Operations.

21

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

	Domestic	International (Millions)	Total
Three months ended September 30, 2013			
Total revenues	$623	$35	$658
Costs and expenses:			
Lease and facility operating	$74	$8	$82
Gathering, processing and transportation	106	—	106
Taxes other than income	30	6	36
Gas management, including charges for unutilized pipeline capacity	201	—	201
Exploration	21	—	21
Depreciation, depletion and amortization	233	8	241
Impairment of costs of acquired unproved reserves (Note 4)	19	—	19
General and administrative	65	3	68
Other—net	7	3	10
Total costs and expenses	$756	$28	$784
Operating income (loss)	$(133)	$7	$(126)
Interest expense	(28)	—	(28)
Interest capitalized	2	—	2
Investment income and other	—	4	4
Income (loss) from continuing operations before income taxes	$(159)	$11	$(148)
Three months ended September 30, 2012			
Total revenues	$642	$35	$677
Costs and expenses:			
Lease and facility operating	$60	$8	$68
Gathering, processing and transportation	124	—	124
Taxes other than income	17	6	23
Gas management, including charges for unutilized pipeline capacity	200	—	200
Exploration	19	3	22
Depreciation, depletion and amortization	236	7	243
General and administrative	64	3	67
Other—net	4	1	5
Total costs and expenses	$724	$28	$752
Operating income (loss)	$(82)	$7	$(75)
Interest expense	(25)	—	(25)
Interest capitalized	2	—	2
Investment income and other	1	6	7
Income (loss) from continuing operations before income taxes	$(104)	$13	$(91)

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

	Domestic	International (Millions)	Total
Nine months ended September 30, 2013			
Total revenues	$1,991	$113	$2,104
Costs and expenses:			
Lease and facility operating	$204	$26	$230
Gathering, processing and transportation	322	2	324
Taxes other than income	89	18	107
Gas management, including charges for unutilized pipeline capacity	666	—	666
Exploration	56	4	60
Depreciation, depletion and amortization	674	25	699
Impairment of costs of acquired unproved reserves (Note 4)	19	—	19
General and administrative	203	11	214
Other—net	18	—	18
Total costs and expenses	$2,251	$86	$2,337
Operating income (loss)	$(260)	$27	$(233)
Interest expense	(82)	—	(82)
Interest capitalized	4	—	4
Investment income and other	4	16	20
Income (loss) from continuing operations before income taxes	$(334)	$43	$(291)
Nine months ended September 30, 2012			
Total revenues	$2,262	$100	$2,362
Costs and expenses:			
Lease and facility operating	$181	$21	$202
Gathering, processing and transportation	379	—	379
Taxes other than income	60	18	78
Gas management, including charges for unutilized pipeline capacity	749	—	749
Exploration	49	11	60
Depreciation, depletion and amortization	700	19	719
Impairment of costs of acquired unproved reserves (Note 4)	117	—	117
General and administrative	197	9	206
Other—net	9	(1)	8
Total costs and expenses	$2,441	$77	$2,518
Operating income (loss)	$(179)	$23	$(156)
Interest expense	(77)	—	(77)
Interest capitalized	7	—	7
Investment income and other	3	22	25
Income (loss) from continuing operations before income taxes	$(246)	$45	$(201)
Total assets			
Total assets as of September 30, 2013	$9,150	$373	$9,523
Total assets as of December 31, 2012	$9,113	$343	$9,456

Note 12. Subsequent Events

In October 2013, we completed the sale of deep rights on approximately 140,000 net acres in the Powder River Basin for approximately $40 million. This sale does not include our producing coal bed methane assets in the Powder River Basin.

23

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 in Part I, Item 1 in this Form 10-Q and our 2012 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.

Overview

The following table presents our production volumes and financial highlights for the three and nine months ended September 30, 2013 and 2012:

	Three months ended September 30,		Nine months ended September 30,	
	2013	2012	2013	2012
Production Sales Data:				
Domestic natural gas (MMcf)	91,392	97,310	271,825	300,819
Domestic oil (MBbls)	1,575	1,076	4,189	3,147
Domestic NGLs (MBbls)	1,811	2,613	5,613	8,138
Domestic combined equivalent volumes (MMcfe) (a)	111,707	119,443	330,638	368,528
Domestic per day combined equivalent volumes (MMcfe/d)	1,214	1,298	1,211	1,345
Domestic combined equivalent volumes (MBoe)	18,618	19,907	55,106	61,421
International combined equivalent volumes (MMcfe) (a)(b)	4,862	5,569	14,839	15,983
International per day combined equivalent volumes (MMcfe/d)	53	61	54	58
Financial Data (millions):				
Total domestic revenues	$623	$642	$1,991	$2,262
Total international revenues	$35	$35	$113	$100
Consolidated operating income (loss)	$(126)	$(75)	$(233)	$(156)
Consolidated capital expenditures	$295	$337	$843	$1,165

(a) Oil and NGLs were converted to MMcfe using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.

(b) Includes approximately 69 percent of Apco's production (which corresponds to our ownership interest in Apco) and other minor directly held interests.

Our third quarter 2013 operating results were $51 million unfavorable compared to third quarter 2012. The primary unfavorable impacts to our quarter over quarter operating results include the absence of $107 million of gains realized in 2012 on natural gas derivatives designated as hedges for accounting purposes, the impact to revenues from lower domestic natural gas and natural gas liquids volumes, higher lease and facility operating expenses, higher operating taxes and a $19 million impairment of costs of acquired unproved reserves in the Kokopelli area of the Piceance Basin recorded in 2013. Favorable impacts include higher domestic oil and condensate prices and production volumes, higher natural gas (excluding hedges) and NGL prices, and lower gathering, processing and transportation expenses.

Our year to date 2013 operating results were $77 million unfavorable compared to year to date 2012. The primary unfavorable impacts include the absence of $346 million of gains realized in 2012 on natural gas derivatives designated as hedges for accounting purposes, $94 million unfavorable change in derivatives not designated as hedges, $73 million related to lower NGL production volumes and $62 million related to lower natural gas production volumes. Operating results were favorably impacted by $237 million related to higher realized domestic natural gas prices (excluding hedges), $124 million from higher domestic oil prices and production volumes, and $55 million lower gathering, processing and transportation costs. Additionally, a $19 million impairment of costs of acquired unproved reserves was recorded for 2013 compared to $117 million of impairments recorded in 2012.

Outlook

For the remainder of 2013, we will focus on growing our oil production and developing oil reserves, primarily those located in the Williston Basin, specifically on the development of reserves in the middle Bakken and upper Three Forks formations of this basin. Continued Williston Basin operational improvements should facilitate the drilling and completion of 51 total wells by the end of 2013.

We will also remain disciplined in the development of our natural gas reserves. We will continue to focus our natural gas drilling effort in the Piceance Basin, because of our scale and efficiency of that operation, together with significant infrastructure already in place. We are moving to increase our natural gas volumes over current production by maintaining seven drilling rigs in the Piceance Basin for the remainder of the year. In the Appalachian Basin, we will initially focus on completing our inventory of drilled locations. Our drilling program in the Appalachian Basin will be limited. Specifically, drilling capital in Susquehanna County will be minimal due to constraints on our third party gatherer's system. Until those constraints have been rectified, we will look to develop opportunities in Westmoreland County in the Appalachian Basin.

We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities and negotiated cost savings on vendor contracts. Additionally, more favorable, previously negotiated gathering and processing contract provisions became effective earlier in 2013.

Approximately 8 percent to 10 percent of our estimated annual capital spending will be for exploratory activities, primarily focused on oil. During 2013, WPX began oil development in New Mexico's San Juan Basin after exploratory drilling yielded commercially economic results from the Gallup Sandstone in the Mancos formation. By the end of 2013, we expect to have drilled 15 wells in 2013 in the Gallup Sandstone with an expected year end exit rate of 3,400 Boe per day. We are also in the process of drilling test wells in another new area. We will also continue to look at purchasing land in these and other areas. Additionally, our Niobrara Shale discovery well in the Piceance Basin produced 2.0 billion cubic feet of natural gas production in the first 10 months of operation. We finished drilling our second Niobrara Shale well which began initial production at the end of the third quarter. A third well was drilled during the third quarter 2013 and will be sidetracked due to a casing failure that occurred before completion operations could be commenced. Two additional Niobrara Shale wells are scheduled to be spud in November 2013.

We anticipate our total capital spending in 2013 will be approximately $1.2 billion. Through September 30, 2013, our capital expenditures totaled $843 million.

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 invest in and grow our production and reserves;
- Continuing to diversify our commodity portfolio through the development of our Bakken Shale oil play position, Gallup Sandstone oil play and liquids-rich basins (primarily Piceance Basin) with high concentrations of NGLs;
- Fully delineate Niobrara Shale potential through drilling and 3-D seismic;
- Continuing to pursue cost improvements and efficiency gains;
- Continuing to invest in exploration projects to add new development opportunities to our portfolio;
- Retaining the flexibility to make adjustments to our planned levels of capital and 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;
- Higher capital costs of developing our properties;
- Lower than expected levels of cash flow from operations;
- Counterparty credit and performance risk;
- General economic, financial markets or industry downturn;
- 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.

While we did see some improvement in natural gas prices during the first nine months of 2013, recent gas prices have softened. The future prices will be considered as we develop our plans for 2014. We continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

From time to time, we may consider strategic acquisitions or dispositions of assets that could be material to our financial condition or results of operations. During second quarter, we completed a data room process for our holdings in Wyoming's Powder River Basin. In management's view, retaining ownership of the assets at the present time represents greater value for shareholders than the bids received. We remain open to the potential sale or partial monetization of these assets in the future. Subsequent to September 30, 2013, we completed the sale of deep rights on approximately 140,000 net acres in the Powder River Basin for approximately $40 million. This sale does not include our producing coal bed methane assets in the Powder River Basin.

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 2013 and 2014, 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 2013		2014	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Natural gas fixed-price—Henry Hub	470	$ 3.59	40	$ 4.35
Natural gas swaptions—Henry Hub	—	$ —	40	$ 4.35
Natural gas collars—Henry Hub	—	$ —	145	$ 4.00 - $4.66
Basis swaps—Northeast	60	$ 0.19	23	$ 0.09
Basis swaps—Mid-Continent	20	$ (0.16)	10	$ (0.14)
Basis swaps—Rockies	20	$ (0.15)	40	$ (0.15)

Crude Oil	Oct - Dec 2013		2014	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Crude oil fixed-price—WTI	8,500	$ 100.70	11,743	$ 94.78
Crude oil fixed-price—LLS	2,500	$ 106.87	—	$ —
Basis swaps—Brent	3,033	$ 9.64	4,463	$ 9.64

Natural Gas Liquids	Oct - Dec 2013		2014	
	Volume (Bbls/d)	Weighted Average Price ($/Gal)	Volume (Bbls/d)	Weighted Average Price ($/Gal)
Propane fixed-price—Mont Belvieu	815	$ 1.165	—	$ —
Natural Gasoline fixed-priced—Mont Belvieu	815	$ 2.265	—	$ —

Additionally, we utilize contracted pipeline capacity to move our production from the Rockies to other locations when pricing differentials are favorable to Rockies pricing. We also hold a long-term obligation to deliver on a firm basis 200,000 MMbtu/d of natural gas at Appalachian monthly index pricing less transportation to a buyer at the White River Hub (Greasewood-Meeker, CO), which is a major market hub exiting the Piceance Basin. Currently, this contract yields a price that is lower than the Rockies index price. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation, which expires in 2014.

Results of Operations

Operations of our company are located in the United States and South America and are organized into domestic and international reportable segments.

Domestic includes natural gas, oil and natural gas liquids development, production and gas management activities located in Colorado, New Mexico, North Dakota, Pennsylvania and Wyoming in the United States. Our development and production techniques specialize in production from tight-sands and shale formations and coal bed methane reserves in the Piceance, San Juan, Powder River, Williston, Appalachian and Green River Basins. 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, storage and related derivatives coupled with the sale of our commodity volumes.

International primarily consists of our ownership in Apco, an oil and gas exploration and production company with activities in Argentina and Colombia.

Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges for accounting purposes. Most all of our commodity derivative contracts entered into after 2011 continue to serve as economic hedges but are not designated as hedges for accounting purposes as we have elected not to utilize hedge accounting on new derivatives instruments. Changes in the fair value of non-hedge derivative instruments, hereafter referred to as economic hedges, are recognized as gains or losses in the earnings of the periods in which they occur, accordingly we believe this will result in future earnings that are more volatile. Hedged derivatives recorded at December 31, 2012 that are included in accumulated other comprehensive income were realized during first-quarter 2013.

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended September 30, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Domestic revenues:				
Natural gas sales	$248	$327	$(79)	(24)%
Oil and condensate sales	154	87	67	77%
Natural gas liquid sales	57	65	(8)	(12)%
Total product revenues	459	479	(20)	(4)%
Gas management	176	186	(10)	(5)%
Net gain (loss) on derivatives not designated as hedges	(15)	(22)	7	32%
Other	3	(1)	4	NM
Total domestic revenues	$623	$642	$(19)	(3)%
Total international revenues	$35	$35	$—	—%
Total revenues	$658	$677	$(19)	(3)%

____

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

Domestic Revenues

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

- $79 million decrease in natural gas sales primarily due to the absence of $107 million of realized gains in 2012 from derivatives designated as hedges and $13 million related to lower production sales volumes offset by $41 million related to higher sales prices. The Company no longer designated derivatives entered into after December 31, 2011 as hedges for accounting purposes. The average realized price per Mcf (excluding hedges) was $2.72 on production sales volumes of 91,392 MMcf for the three months ended September 30, 2013 compared to $2.26 on production sales volumes of 97,310 MMcf for the three months ended September 30, 2012. Including the impact of realized gains on derivatives designated as hedges, our natural gas price per Mcf was $2.72 for 2013 compared to $3.35 for 2012. Also included in the realized price for 2013 is the impact of an $11 million adjustment related to prior quarters which is offset in gathering, processing and transportation expense.
- $67 million increase in oil and condensate sales reflects increased production sales volumes of 1,575 MBbls compared to 1,076 MBbls as well as a higher price per barrel of $97.91 compared to $82.31 (including the impact of hedges in 2012) for the three months ended September 30, 2013 and 2012, respectively. The increase in production sales volumes primarily relate to increased production in the Williston Basin where the per day volumes were 14.0

MBbls per day for third quarter 2013 compared to 9.6 MBbls per day for the same period in 2012. The San Juan Basin also had production of 1.1 MBbls per day for third quarter 2013.

- $8 million decrease in natural gas liquids sales reflects decreased production sales volumes of 1,811 MBbls for the three months ended September 30, 2013 compared to 2,613 MBbls for the same period in 2012, part of this decrease relates to lower ethane recovery rates as a result of ethane prices in the Piceance Basin during 2013. The average per barrel price for natural gas liquids was $31.19 compared to $24.43 for the three months ended September 30, 2013 and 2012, respectively, and reflects a change in the composition of the barrel due to lower ethane recovery rates.

- $10 million decrease in gas management revenues primarily due to 17 percent lower natural gas sales volumes partially offset by a 23 percent increase in average prices on physical natural gas sales.
- $7 million change in net gain (loss) on derivatives not designated as hedges reflects the following:

	Three months ended September 30, 2013	2012
	(Millions)	
Unrealized gain (loss)	$(13)	$(31)
Realized gain (loss)	(2)	9
Net gain (loss)	$(15)	$(22)

Both the unrealized loss and realized loss in third quarter 2013 primarily related to crude derivatives. The unrealized loss in 2012 primarily related to crude and NGL derivatives and the realized gain in 2012 related to natural gas and NGL derivatives.

Cost and operating expense and operating income (loss) analysis:

	Three months ended September 30, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$74	$60	$(14)	(23)%
Gathering, processing and transportation	106	124	18	15%
Taxes other than income	30	17	(13)	(76)%
Gas management, including charges for unutilized pipeline capacity	201	200	(1)	(1)%
Exploration	21	19	(2)	(11)%
Depreciation, depletion and amortization	233	236	3	1%
Impairment of costs of acquired unproved reserves	19	—	(19)	NM
General and administrative	65	64	(1)	(2)%
Other—net	7	4	(3)	(75)%
Total domestic costs and expenses	$756	$724	$(32)	(4)%
International costs and expenses:				
Lease and facility operating	$8	$8	$—	—%
Taxes other than income	6	6	—	—%
Exploration	—	3	3	100%
Depreciation, depletion and amortization	8	7	(1)	(14)%
General and administrative	3	3	—	—%
Other—net	3	1	(2)	(200)%
Total international costs and expenses	$28	$28	$—	—%
Total costs and expenses	$784	$752	$(32)	(4)%
Domestic operating income (loss)	$(133)	$(82)	$(51)	(62)%
International operating income	$7	$7	$—	—%

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

28

Domestic Costs

Significant components on our domestic costs and expenses are comprised of the following:

- $14 million increase in lease and facility operating expense primarily relates to the impact of increased Williston Basin production in relation to our overall portfolio as well as increased water disposal costs in other basins due in part to decreased drilling in the Appalachian Basin and the corresponding utilization of produced water in the well hydraulic fracturing process. Lease and facility operating expense averaged $0.65 per Mcfe for the three months ended September 30, 2013 compared to $0.51 per Mcfe for the same period in 2012.
- $18 million decrease in gathering, processing and transportation charges primarily related to new favorable contract terms for gathering and processing services in the Piceance Basin as well as lower volumes, partially offset by the $6 million impact of costs associated with the transportation of Williston production to points outside the basin. Also included in gathering, processing and transportation costs for the three months ended September 30, 2013, was a $13 million adjustment related to prior quarters that is offset in revenues. Gathering, processing and transportation expenses averaged $0.94 per Mcfe compared to $1.04 per Mcfe for the three months ended September 30, 2013 and 2012, respectively. Excluding the adjustment, gathering, processing and transportation expenses would have averaged $1.05 per Mcfe in 2013.
- $13 million increase in taxes other than income from 2013 compared to 2012 relates to the increase in natural gas prices (excluding derivatives), increased crude oil production volumes and higher crude oil prices. Taxes other than income averaged $0.27 per Mcfe for the third quarter 2013 compared to $0.14 per Mcfe for the same period in 2012.
- The change in gas management expenses reflect the 32 percent increase in average prices on physical natural gas cost of sales offset by 17 percent lower natural gas sales volumes. Also included in gas management expenses are $17 million and $12 million for the three months ended September 30, 2013 and 2012, respectively, for unutilized pipeline capacity. Gas management expenses for the period ended September 30, 2013 also includes $1 million related to lower of cost or market charges to the carrying value of natural gas inventories in storage.
- During the three months ended September 30, 2013, our depreciation, depletion and amortization averaged $2.09 per Mcfe compared to an average $1.98 per Mcfe for the same period in 2012. The increase in the rate is due to Williston Basin and Marcellus Shale becoming a higher percentage of our production.
- $19 million of property impairments of cost of acquired unproved reserves for the three months ended September 30, 2013, as previously discussed.
- General and administrative expense averaged $0.58 per Mcfe compared to $0.53 per Mcfe for the three months ended September 30, 2013 and 2012, respectively.
- Other expenses for three months ended September 30, 2013 includes a $7 million accrual for litigation.

Consolidated results below operating income (loss)

	Three months ended September 30, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Consolidated operating income (loss)	$(126)	$(75)	$(51)	(68)%
Interest expense	(28)	(25)	(3)	(12)%
Interest capitalized	2	2	—	—%
Investment income and other	4	7	(3)	(43)%
Income (loss) from continuing operations before income taxes	(148)	(91)	(57)	(63)%
Provision (benefit) for income taxes	(32)	(28)	4	14%
Income (loss) from continuing operations	(116)	(63)	(53)	(84)%
Income (loss) from discontinued operations	—	2	(2)	(100)%
Net income (loss)	(116)	(61)	(55)	(90)%
Less: Net income (loss) attributable to noncontrolling interests	(2)	3	(5)	NM
Net income (loss) attributable to WPX Energy	$(114)	$(64)	$(50)	(78)%

____

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

Income taxes changed favorably primarily due to greater pre-tax loss for third quarter 2013 compared to third quarter 2012. Income taxes in 2013 include a $9 million deferred tax provision related to the increase in a valuation allowance on certain state deferred tax assets. Income taxes in 2013 also included a $10 million provision related to the impact of the new capital tax law in Argentina. In September 2013, the Argentine government enacted tax reform legislation related to dividends and capital gains which will apply to the Argentine operations of our consolidated investment in Apco, a Cayman Islands corporation. The new 10 percent dividend tax will be accrued by Apco when dividends are paid by its Argentine investments in future periods. The capital gains tax applies to the sale of Argentine securities by a non Argentine resident, such as Apco, making such sales subject to an effective 13.5 percent tax on the gross proceeds. As a result, Apco recorded approximately $14 million of a foreign deferred tax expense during third quarter 2013 for the excess book basis over tax basis in its equity investment in Petrolera Entre Lomas S.A., of which approximately $12 million relates to basis differences that occurred prior to 2013. This accrual was partially offset by approximately $4 million of U.S. deferred tax benefit recorded by WPX related to the additional Argentine tax. See Note 7 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 net income (loss) attributable to noncontrolling interests is primarily due to a $4 million impact in 2013 as a result of the new Argentine tax law.

Nine Month-Over-Nine Month Results of Operations

Revenue Analysis

	Nine months ended September 30, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Domestic revenues:				
Natural gas sales	$821	$987	$(166)	(17)%
Oil and condensate sales	386	262	124	47%
Natural gas liquid sales	168	234	(66)	(28)%
Total product revenues	1,375	1,483	(108)	(7)%
Gas management	642	710	(68)	(10)%
Net gain (loss) on derivatives not designated as hedges	(31)	63	(94)	NM
Other	5	6	(1)	(17)%
Total domestic revenues	$1,991	$2,262	$(271)	(12)%
Total international revenues	$113	$100	$13	13%
Total revenues	$2,104	$2,362	$(258)	(11)%

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

Domestic Revenues

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

- $166 million decrease in natural gas sales primarily due to the absence of $346 million of realized gains from derivatives designated as hedges and $62 million related to lower volumes, partially offset by a $237 million increase related to higher prices (excluding hedges). The Company no longer designated derivatives entered into after December 31, 2011 as hedges for accounting purposes. The average realized price per Mcf (excluding hedges) was $3.00 on production sales volumes of 271,825 MMcf for the nine months ended September 30, 2013 compared to $2.13 on production sales volumes of 300,819 MMcf for the nine months ended September 30, 2012. Including the impact of realized gains on derivatives designated as hedges, our natural gas price per Mcf was $3.02 for 2013 compared to $3.28 for 2012. We also incurred $21 million in 2013 of realized losses on natural gas derivatives that were not designated as hedges, compared to $10 million in 2012 of realized gains; however, these losses are included in net gain (loss) on derivatives not designated as hedges as discussed below. The decrease in our production sales volumes is due in part to our disciplined development of natural gas reserves in a low natural gas price environment. However, natural gas production in the Appalachian Basin has increased over prior year but third party infrastructure constraints are continuing. We also have increased drilling in the Piceance Basin that will increase production from current levels in that basin. Natural gas production from the Piceance Basin represents approximately 60 percent of our total domestic natural gas production.

- $124 million increase in oil and condensate sales reflects both increased production sales volumes of 4,189 MBbls compared to 3,147 MBbls and increased price per barrel of $92.17 compared to $83.54 (including the impact of hedges in 2012) for the nine months ended September 30, 2013 and 2012, respectively. The increase in production sales volumes primarily relate to increased production in the Williston Basin where the volumes were 12.6 MBbls per day for the first nine months 2013 compared to 8.9 MBbls per day for the same period in 2012.
- $66 million decrease in natural gas liquids sales reflects decreased production sales volumes of 5,613 MBbls for the nine months ended September 30, 2013 compared to 8,138 MBbls for the same period in 2012, part of this decrease relates to lower ethane recovery rates as a result of ethane prices in the Piceance Basin during 2013. The average per barrel price for natural gas liquids was $29.85 compared to $28.68 for the nine months ended September 30, 2013 and 2012 respectively, and reflects a change in the composition of the barrel due to lower ethane recovery rates.
- $68 million decrease in gas management revenues primarily due to 36 percent lower natural gas sales volumes partially offset by a 49 percent increase in average prices on physical natural gas sales. We experienced a decrease of $83 million in related gas management costs and expenses.
- $94 million change in net gain (loss) on derivatives not designated as hedges reflects the following:

	Nine months ended September 30,	
	2013	2012
	(Millions)	
Unrealized gain (loss)	$(18)	$28
Realized gain (loss)	(13)	35
Net gain (loss)	$(31)	$63

The unrealized loss in 2013 primarily related to crude derivatives and the unrealized gain in 2012 primarily related to crude and NGL derivatives. The realized loss in 2013 primarily reflects $21 million related to natural gas derivatives. The realized gain in 2012 related to natural gas and natural gas liquids derivatives.

International Revenues

International revenues increased primarily due to the reinstatement of a government hydrocarbon subsidy program in Argentina in 2013.

Cost and operating expense and operating income (loss) analysis:

	Nine months ended September 30, 2013 (Millions)	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Domestic costs and expenses:				
Lease and facility operating	$204	$181	$(23)	(13)%
Gathering, processing and transportation	322	379	57	15%
Taxes other than income	89	60	(29)	(48)%
Gas management, including charges for unutilized pipeline capacity	666	749	83	11%
Exploration	56	49	(7)	(14)%
Depreciation, depletion and amortization	674	700	26	4%
Impairment of costs of acquired unproved reserves	19	117	98	84%
General and administrative	203	197	(6)	(3)%
Other—net	18	9	(9)	(100)%
Total domestic costs and expenses	$2,251	$2,441	$190	8%
International costs and expenses:				
Lease and facility operating	$26	$21	$(5)	(24)%
Gathering, processing and transportation	2	—	(2)	NM
Taxes other than income	18	18	—	—%
Exploration	4	11	7	64%
Depreciation, depletion and amortization	25	19	(6)	(32)%
General and administrative	11	9	(2)	(22)%
Other—net	—	(1)	(1)	(100)%
Total international costs and expenses	$86	$77	$(9)	(12)%
Total costs and expenses	$2,337	$2,518	$181	7%
Domestic operating income (loss)	$(260)	$(179)	$(81)	(45)%
International operating income	$27	$23	$4	17%

____

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

Domestic Costs

Significant components on our domestic costs and expenses are comprised of the following:

- $23 million increase in lease and facility operating expense primarily relates to the impact of increased Williston Basin production in relation to our overall portfolio, along with higher workover expense and increased water disposal costs in other basins. The increased water disposal costs were due in part to decreased drilling in the Appalachian Basin and the corresponding utilization of produced water in the well hydraulic fracturing process. Lease and facility operating expense averaged $0.62 per Mcfe for the nine months ended September 30, 2013 compared to $0.49 for the same period in 2012 and the increase partially reflects the growth of Williston Basin in relation to the total.
- $57 million decrease in gathering, processing and transportation charges primarily related to lower volumes and the effect of new favorable contract terms for gathering and processing services in the Piceance Basin. Gathering, processing and transportation for 2012 includes a $9 million adjustment related to royalty calculations for prior periods. Gathering, processing and transportation charges averaged $0.97 per Mcfe for 2013 and $1.00 per Mcfe (excluding the adjustment discussed above) for 2012.
- $29 million increase in taxes other than income for 2013 compared to 2012 relates to the increase in natural gas prices (excluding derivatives), increased crude oil production volumes and higher crude oil prices. Taxes other than income averaged $0.27 per Mcfe for the first nine months of 2013 compared to $0.16 per Mcfe for the same period in 2012.
- $83 million decrease in gas management expenses, primarily due to 36 percent lower natural gas sales volumes partially offset by a 47 percent increase in average prices on physical natural gas cost of sales. Also included in gas

management expenses are $44 million and $35 million for the nine months ended

32

September 30, 2013 and 2012, respectively, for unutilized pipeline capacity. Gas management expenses also includes $1 million and $11 million related to lower of cost or market charges to the carrying value of natural gas inventories in storage for the nine months ended September 30, 2013 and 2012, respectively.

- $7 million increase in exploration expense relates to higher geological and geophysical costs for 2013.
- $26 million decrease in depreciation, depletion and amortization primarily due to lower production volumes in 2013 compared to 2012. Also during 2013, we have adjusted our proved reserves used for the calculation of depletion and amortization to reflect the impact of an increase in the 12 month average price and continued lower ethane recovery; this resulted in a net $13 million reduction of depreciation, depletion and amortization expense for the nine months ended September 30, 2013. During the nine months ended September 30, 2013, our depreciation, depletion and amortization averaged $2.04 per Mcfe compared to an average $1.90 per Mcfe for the same period in 2012. This increase partially reflects the growth of the Williston Basin as part of our portfolio.
- $19 million property impairment of cost of acquired unproved reserves in the Kokopelli area of the Piceance Basin for the nine months ended September 30, 2013 compared to $117 million of impairments, primarily in the Powder River Basin, for the nine months ended September 30, 2012, as previously discussed.
- General and administrative expense averaged $0.61 per Mcfe compared to $0.53 per Mcfe for the nine months ended September 30, 2013 and 2012, respectively.
- $9 million change in other expenses for 2013 includes a $7 million accrual for litigation.

International costs

International costs increased primarily due to higher depreciation, depletion and amortization costs related to our Colombian operations which began production in the third quarter of 2012 as well as higher lease and facility operating costs. These increases were partially offset by lower exploration expense for the first nine of 2013 compared to the same period in 2012.

Consolidated results below operating income (loss)

	Nine months ended September 30, 2013	2012	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Consolidated operating income (loss)	$(233)	$(156)	$(77)	(49)%
Interest expense	(82)	(77)	(5)	(6)%
Interest capitalized	4	7	(3)	(43)%
Investment income and other	20	25	(5)	(20)%
Income (loss) from continuing operations before income taxes	(291)	(201)	(90)	(45)%
Provision (benefit) for income taxes	(84)	(71)	13	18 %
Income (loss) from continuing operations	(207)	(130)	(77)	(59)%
Income (loss) from discontinued operations	—	23	(23)	(100)%
Net income (loss)	(207)	(107)	(100)	(93)%
Less: Net income (loss) attributable to noncontrolling interests	5	10	(5)	(50)%
Net income (loss) attributable to WPX Energy	$(212)	$(117)	$(95)	(81)%

Investment income results are primarily from equity earnings associated with our international and domestic equity investments.

Benefit for income taxes changed favorably primarily due to the greater pre-tax loss in 2013 compared to 2012. Income taxes in 2013 include a $9 million deferred tax provision related to the increase in a valuation allowance on certain state deferred tax assets. Income taxes in 2013 also included a $10 million provision related to the impact of the new capital tax law in Argentina. In September 2013, the Argentine government enacted tax reform legislation related to dividends and capital gains which will apply to the Argentine operations of our consolidated investment in Apco, a Cayman Islands corporation. The new 10 percent dividend tax will be accrued by Apco when dividends are paid by its Argentine investments in future periods. The capital gains tax applies to the sale of Argentine securities by a non Argentine resident, such as Apco, making such sales subject to an effective 13.5 percent tax on the gross proceeds. As a result, Apco recorded approximately $14 million of a foreign deferred tax expense during third quarter 2013 for the excess book basis over tax basis in its equity investment in Petrolera Entre Lomas S.A., of which approximately $12 million relates to basis differences that occurred prior to

33

2013. This accrual was partially offset by approximately $4 million of U.S. deferred tax benefit recorded by WPX related to the additional Argentine tax. See Note 7 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 net income attributable to noncontrolling interests is primarily due to a $4 million impact in 2013 as a result of the new Argentine tax law.

Management's Discussion and Analysis of Financial Condition and Liquidity
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 2013 will continue to be expected cash flow from operations and borrowings on our $1.5 billion credit facility. The combination of these sources should be sufficient to allow us to pursue our business strategy and goals for the remainder of 2013.
We note the following assumptions for the remainder of 2013:

- Our capital expenditures, including international, are estimated to be approximately $1.2 billion in 2013, and are generally considered to be largely discretionary; and
- Apco's liquidity requirements will continue to be provided from its cash flows from operations and cash on hand.

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;
- 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 leaseholds; and
- Reduced access to our credit facility.

Liquidity
We plan to conservatively manage our balance sheet and our level of capital spending. 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 2013. 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 bank financings, proceeds from the issuance of long-term debt and equity securities and proceeds from asset sales.
Sources (Uses) of Cash

	Nine months ended September 30,	
	2013	2012
	(Millions)	
Net cash provided (used) by:		
Operating activities	$518	$589
Investing activities	(836)	(854)
Financing activities	273	(21)
Increase (decrease) in cash and cash equivalents	$(45)	$(286)

Operating activities
Our net cash provided by operating activities for the nine months ended September 30, 2013 decreased from the same period in 2012 primarily due to the decrease in our operating results driven by lower natural gas (including the impact of hedges) and NGL sales revenues.
Investing activities
Significant transactions include expenditures for drilling and completion of $691 million and $955 million for the nine months ended September 30, 2013 and 2012, respectively. Also included in 2012 are proceeds from asset sales of $310 million primarily related to the disposition of the Barnett Shale and Arkoma Basin properties.

34

Financing activities

Net cash provided by financing activities in 2013 primarily relates to borrowings under our revolving credit facility agreement (see Note 6 of Notes to Consolidated Financial Statements) made to partially fund capital expenditures during 2013. The use of cash in 2012 primarily relates to changes in our cash overdrafts.

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, 2013 or at December 31, 2012.

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 2013.

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.

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 market forward prices, while correlations and volatilities are derived from historical forward prices. 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, 2013 and a net asset of $1 million at December 31, 2012. The value at risk for contracts held for trading purposes was less than $1 million at both September 30, 2013 and December 31, 2012.

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our natural gas purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $22 million at September 30, 2013 and a net asset of $39 million at December 31, 2012.

The value at risk for derivative contracts held for nontrading purposes was $12 million at September 30, 2013, and $6 million at December 31, 2012. During the last 12 months, our value at risk for these contracts ranged from a high of $15 million to a low of $6 million.

35

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 controls 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.

Third-Quarter 2013 Changes in Internal Controls

There have been no changes during the third quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our Internal Controls.

Part II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 8 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors

Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 2012, 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, 2013.

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

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

EXHIBITS

Exhibit No.	Description
2.1	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)
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 (File No. 001-35322) filed with the SEC on January 6, 2012)
3.2	Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
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)
10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) 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 (File No. 001-35322) 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 (File No. 001-35322) 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)
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 (File No. 001-35322) 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 (File No. 001-35322) filed with the SEC on July 23, 2012) (1)

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.

Exhibit No.	Description
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 (File No. 001-35322) 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 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, 2012) (1)
10.14	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.14 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.15	Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.16	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)
10.17	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)
12*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema

101.CAL**	XBRL Taxonomy Extension Calculation Linkbase
101.DEF**	XBRL Taxonomy Extension Definition Linkbase
101.LAB**	XBRL Taxonomy Extension Label Linkbase
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith
** Furnished herewith
(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/ J. KEVIN VANN
J. Kevin Vann
Controller (Principal Accounting Officer)

Date: November 7, 2013