

WPX ENERGY, INC.
Form 10-Q
May 07, 2014

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

Form 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2014

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

(State or Other Jurisdiction of

Incorporation or Organization)

45-1836028

(IRS Employer

Identification No.)

3500 One Williams Center,

Tulsa, Oklahoma

(Address of Principal Executive Offices)

855-979-2012

(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class

Common Stock, \$0.01 par value

Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

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

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

Large accelerated filer ☒

Accelerated filer ☐

Non-accelerated filer ☐ (Do not check if a smaller reporting company)

Smaller reporting company ☐

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

The number of shares outstanding of the registrant's common stock at May 6, 2014 were 202,150,303.

WPX Energy, Inc.
Index

		Page
Part I.	Financial Information	
Item 1.	Financial Statements (Unaudited)	
	<u>Consolidated Balance Sheets as of March 31, 2014 and December 31, 2013</u>	4
	<u>Consolidated Statements of Operations for the three months ended March 31, 2014 and 2013</u>	5
	<u>Consolidated Statements of Comprehensive Income (Loss) for the three months ended March 31, 2014 and 2013</u>	6
	<u>Consolidated Statements of Changes in Equity for the three months ended March 31, 2014</u>	7
	<u>Consolidated Statements of Cash Flows for the three months ended March 31, 2014 and 2013</u>	8
	<u>Notes to Consolidated Financial Statements</u>	9
Item 2.	<u>Management's Discussion and Analysis of Financial Condition and Results of Operations</u>	22
Item 3.	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	30
Item 4.	<u>Controls and Procedures</u>	31
Part II.	Other Information	
Item 1.	<u>Legal Proceedings</u>	33
Item 1A.	<u>Risk Factors</u>	33
Item 2.	<u>Unregistered Sales of Equity Securities and Use of Proceeds</u>	33
Item 3.	<u>Defaults Upon Senior Securities</u>	33
Item 4.	<u>Mine Safety Disclosures</u>	33
Item 5.	<u>Other Information</u>	33
Item 6.	<u>Exhibits</u>	34

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, 2013.

WPX Energy, Inc.
Consolidated Balance Sheets
(Unaudited)

	March 31, 2014	December 31, 2013
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	\$58	\$ 99
Accounts receivable, net of allowance of \$7 million at March 31, 2014 and December 31, 2013	664	536
Deferred income taxes	46	49
Derivative assets	25	50
Inventories	68	72
Margin deposits	72	71
Other	28	45
Total current assets	961	922
Investments	148	145
Properties and equipment (successful efforts method of accounting)	13,052	12,686
Less—accumulated depreciation, depletion and amortization	(5,654)	(5,445)
Properties and equipment, net	7,398	7,241
Derivative assets	17	7
Other noncurrent assets	113	114
Total assets	\$8,637	\$ 8,429
Liabilities and Equity		
Current liabilities:		
Accounts payable	\$758	\$ 652
Accrued and other current liabilities	147	190
Customer margin deposits payable	12	55
Derivative liabilities	128	110
Total current liabilities	1,045	1,007
Deferred income taxes	807	788
Long-term debt	2,039	1,916
Derivative liabilities	7	12
Asset retirement obligations	367	358
Other noncurrent liabilities	139	138
Contingent liabilities and commitments (Note 7)		
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; 202.2 million shares issued at March 31, 2014 and 201 million shares issued at December 31, 2013)	2	2
Additional paid-in-capital	5,520	5,516
Accumulated deficit	(1,390)	(1,408)
Accumulated other comprehensive income (loss)	(1)	(1)
Total stockholders' equity	4,131	4,109
Noncontrolling interests in consolidated subsidiaries	102	101
Total equity	4,233	4,210
Total liabilities and equity	\$8,637	\$ 8,429

See accompanying notes.

4

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

	Three months ended March 31,	
	2014	2013
	(Millions, except per-share amounts)	
Revenues:		
Product revenues:		
Natural gas sales	\$384	\$267
Oil and condensate sales	175	139
Natural gas liquid sales	61	54
Total product revenues	620	460
Gas management	561	261
Net gain (loss) on derivatives not designated as hedges (Note 9)	(195)	(94)
Other	1	4
Total revenues	987	631
Costs and expenses:		
Lease and facility operating	79	75
Gathering, processing and transportation	106	107
Taxes other than income	47	35
Gas management, including charges for unutilized pipeline capacity	391	243
Exploration (Note 3)	15	19
Depreciation, depletion and amortization	207	231
General and administrative	72	72
Other—net	3	7
Total costs and expenses	920	789
Operating income (loss)	67	(158)
Interest expense	(29)	(26)
Interest capitalized	—	1
Investment income and other	4	7
Income (loss) before income taxes	42	(176)
Provision (benefit) for income taxes	23	(63)
Net income (loss)	19	(113)
Less: Net income (loss) attributable to noncontrolling interests	1	3
Net income (loss) attributable to WPX Energy, Inc.	\$18	\$(116)
Amounts attributable to WPX Energy, Inc. (Note 2):		
Earnings (loss) per common share:		
Basic	\$0.09	\$(0.58)
Diluted	\$0.09	\$(0.58)
Weighted-average number of shares (millions):		
Basic	201.5	199.9
Diluted	205.2	199.9
See accompanying notes.		

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

	Three months ended March 31,	
	2014	2013
	(Millions)	
Net income (loss) attributable to WPX Energy, Inc.	\$ 18	\$(116)
Other comprehensive income (loss):		
Net reclassifications into earnings of net cash flow hedge realized gains, net of tax (a)	—	(3)
Other comprehensive income (loss), net of tax	—	(3)
Comprehensive income (loss) attributable to WPX Energy, Inc.	\$ 18	\$(119)

Net reclassifications into earnings of net cash flow hedge realized gains are net of \$2 million of income tax for the (a)three month ended March 31, 2013. Before tax amounts realized and reclassified to natural gas sales revenues on the Consolidated Statements of Operations were \$5 million for the three months ended March 31, 2013.

See accompanying notes.

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

	WPX Energy, Inc., Stockholders					Noncontrolling	
	Common	Additional	Accumulated	Accumulated	Total	Interests in	Total
	Stock	Paid-In-	Deficit	Other	Stockholders'	Consolidated	Equity
		Capital		Comprehensive	Equity	Subsidiaries(a)	
				Income (Loss)			
(Millions)							
Balance at December 31, 2013	\$2	\$5,516	\$ (1,408)	\$ (1)	\$ 4,109	\$ 101	\$4,210
Comprehensive income (loss):							
Net income (loss)	—	—	18	—	18	1	19
Other comprehensive loss	—	—	—	—	—	—	—
Comprehensive income (loss)							19
Stock based compensation	—	4	—	—	4	—	4
Contribution from noncontrolling interest						—	—
Balance at March 31, 2014	\$2	\$5,520	\$ (1,390)	\$ (1)	\$ 4,131	\$ 102	\$4,233

(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)

	Three months ended March 31, 2014 2013 (Millions)	
Operating Activities		
Net income (loss)	\$ 19	\$(113)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	207	231
Deferred income tax provision (benefit)	21	(68)
Provision for impairment of properties and equipment (including certain exploration expenses)	11	14
Amortization of stock-based awards	7	8
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	(128)) 33
Inventories	4	12
Margin deposits and customer margin deposit payable	(44)) (11)
Other current assets	20	(9)
Accounts payable	104	5
Accrued and other current liabilities	(51)) (63)
Changes in current and noncurrent derivative assets and liabilities	27	103
Other, including changes in other noncurrent assets and liabilities	9	2
Net cash provided by operating activities	206	144
Investing Activities		
Capital expenditures (a)	(352)) (271)
Other	(2)) —
Net cash used in investing activities	(354)) (271)
Financing Activities		
Proceeds from common stock	4	1
Borrowings on credit facility	622	80
Payments on credit facility	(497)) —
Other	(17)) 6
Net cash provided by financing activities	112	87
Net increase (decrease) in cash and cash equivalents	(36)) (40)
Effect of exchange rate changes on cash and cash equivalents	(5)) (1)
Cash and cash equivalents at beginning of period	99	153
Cash and cash equivalents at end of period	\$58	\$112
(a) Increase to properties and equipment	\$(372)) \$(277)
Changes in related accounts payable and accounts receivable	20	6
Capital expenditures	\$(352)) \$(271)
See accompanying notes.		

WPX Energy, Inc.

Notes to Consolidated Financial Statements

Note 1. Basis of Presentation and Description of Business

Basis of Presentation

The accompanying interim consolidated financial statements do not include all the notes included in our annual financial statements and, therefore, should be read in conjunction with the consolidated financial statements and notes thereto for the year ended December 31, 2013 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 March 31, 2014, results of operations for the three months ended March 31, 2014 and 2013, changes in equity for the three months ended March 31, 2014 and cash flows for the three months ended March 31, 2014 and 2013.

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, Williston, San Juan, Powder River, 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".

Note 2. Earnings (Loss) Per Common Share

The following table summarizes the calculation of earnings per share.

	Three months ended March 31, 2014 2013 (Millions, except per-share amounts)	
Income (loss) attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	\$ 18	\$(116)
Basic weighted-average shares	201.5	199.9
Effect of dilutive securities (a):		
Nonvested restricted stock units and awards	2.7	—
Stock options	1.0	—
Diluted weighted-average shares	205.2	199.9
Earnings (loss) per common share:		
Basic	\$0.09	\$(0.58)
Diluted	\$0.09	\$(0.58)

(a) For the three months ended March 31, 2013, 1.9 million weighted-average nonvested restricted stock units and awards and 0.8 million weighted-average stock options 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. for the three months ended March 31, 2013.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

The table below includes information related to stock options that were outstanding at March 31, 2014 and 2013 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the first quarter weighted-average market price of our common shares.

	March 31, 2014	2013
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
First quarter weighted-average market price	\$18.44	\$15.27

Note 3. Exploration Expenses

The following table presents a summary of exploration expenses.

	Three months ended March 31, 2014	2013 (Millions)
Geologic and geophysical costs	\$5	\$5
Dry hole costs	—	1
Unproved leasehold property impairment, amortization and expiration	10	13
Total exploration expenses	\$15	\$19

Note 4. Inventories

	March 31, 2014 (Millions)	December 31, 2013
Natural gas in underground storage	\$—	\$13
Crude oil production in transit	12	10
Material, supplies and other	56	49
	\$68	\$72

During the first quarter of 2014, we sold our natural gas in underground storage.

Note 5. Debt and Banking Arrangements

As of the indicated dates, our debt consisted of the following:

	March 31, 2014 (Millions)	December 31, 2013
5.250% Senior Notes due 2017	\$400	\$400
6.000% Senior Notes due 2022	1,100	1,100
Credit facility agreement	535	410
Apco	8	8
Other	1	1
Total debt	\$2,044	\$1,919
Less: Current portion of long-term debt	5	3
Total long-term debt	\$2,039	\$1,916

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 March 31, 2014, the variable interest rate was 2.17 percent on the \$535 million outstanding under the Credit Facility Agreement.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

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 March 31, 2014, a total of \$362 million in letters of credit have been issued.

Note 6. Provision (Benefit) for Income Taxes

The provision (benefit) for income taxes from continuing operations includes:

	Three months ended March 31, 2014 2013 (Millions)	
Current:		
Federal	\$ 1	\$ 1
State	—	—
Foreign	1	4
	2	5
Deferred:		
Federal	6	(62)
State	15	(6)
Foreign	—	—
	21	(68)
Total provision (benefit)	\$23	\$(63)

Tax reform legislation was enacted by the state of New York on March 31, 2014, and has an impact on us as a result of our marketing activities in the state. Key components of this reform measure relative to our business include water’s edge unitary combined reporting, single sales factor apportionment and the application of “economic nexus” to corporations with sales of \$1 million or more to New York customers. Generally accepted accounting principles require that we adjust our state deferred tax liability for the estimated impact of this legislation in the period of enactment. As a result we recorded an additional \$9 million of deferred tax expense in the first quarter to accrue for the impact of this new legislation.

The effective income tax rate of the total provision for the three months ended March 31, 2014, is greater than the federal statutory rate due primarily to state income taxes, partially offset by taxes on foreign operations.

The effective income tax rate of the total benefit for the three months ended March 31, 2013, is greater than the federal statutory rate due primarily to state income taxes, partially offset by taxes on foreign operations.

As of March 31, 2014, 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.

Pursuant to our tax sharing agreement with The Williams Companies, Inc. (“Williams”), we remain responsible for the tax from audit adjustments related to our business for periods prior to the spin-off. The 2011 consolidated tax filing by Williams is currently being audited by the IRS and is the only pre spin-off period for which we continue to have exposure to audit adjustments as part of Williams. We are not aware of any significant issues related to our business, but the alternative minimum tax credit deferred tax asset that was allocated to us by Williams at the time of the spin-off could change due to audit issues unrelated to our business.

Note 7. 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

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

royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim related to the issue of whether we are required to have proportionately increased the value of natural gas by transporting that gas on mainline transmission lines and, if required, whether we did so and are entitled to deduct a proportionate share of transportation costs in calculating royalty payments. Plaintiffs had claimed damages of approximately \$20 million plus interest for the period from July 2000 to July 2008. The court issued pretrial orders finding that we do bear the burden of demonstrating enhancement of the value of gas in order to deduct transportation costs and that the enhancement test must be applied on a monthly basis in order to determine the reasonableness of post-production transportation costs. Trial occurred in December 2013 on the issue of whether we have met that burden. Following that trial, the court issued its order rejecting plaintiffs' proposed standard and accepting our position as to the methodology to use in determining the standard by which our activity should be judged. We are in the process of conducting an accounting under that standard. However, we continue to 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.

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 April 2007 through March 2014, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately \$109 million.

Environmental matters

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

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

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 FERC approved settlement agreement with certain California utilities aimed at eliminating this exposure. Once implemented, 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 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 March 31, 2014, 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.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

Summary

As of March 31, 2014 and December 31, 2013, the Company had accrued approximately \$16 million for loss contingencies associated with royalty litigation and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

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

Note 8. Fair Value Measurements

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

	March 31, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	\$15	\$27	\$—	\$42	\$30	\$26	\$1	\$57
Energy derivative liabilities	\$58	\$77	\$—	\$135	\$83	\$38	\$1	\$122
Total debt (a)	\$—	\$2,093	\$—	\$2,093	\$—	\$1,945	\$—	\$1,945

(a) The carrying value of total debt, excluding capital leases, was \$2,043 million and \$1,918 million as of March 31, 2014 and December 31, 2013, 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.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

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 100 percent of the net fair value of our derivatives portfolio expiring at the end of 2015. Due to the nature of the products and tenure, we are consistently able to obtain market pricing. All pricing is reviewed on a daily basis and is formally validated with broker quotes or market indications and documented on a monthly basis.

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 were less than \$1 million at March 31, 2014, and consist primarily of natural gas index transactions that are used to manage our physical requirements.

Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. No significant transfers occurred during the periods ended March 31, 2014 and 2013.

There have been no material changes in the fair value of our net energy derivatives and other assets classified as Level 3 in the fair value hierarchy.

Note 9. 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 associated with these contracts. Derivatives for transportation and storage contracts economically hedge the expected cash flows generated by those agreements.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

The following table sets forth the derivative notional volumes that are economic hedges of production volumes as well as notional volumes of the net long (short) positions of derivatives primarily related to storage and transportation contracts, both which are included in our commodity derivatives portfolio as of March 31, 2014.

Derivatives related to production

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)	Weighted Average Price (c)
Crude Oil	Apr-Dec 2014	Fixed Price Swaps	WTI	(12,750) \$94.62
Crude Oil	Apr-Dec 2014	Basis Swaps	Brent	(2,978) \$9.64
Natural Gas	Apr-Dec 2014	Fixed Price Swaps	Henry Hub	(315) \$4.19
Natural Gas	Apr-Dec 2014	Swaptions	Henry Hub	(50) \$4.24
Natural Gas	Apr-Dec 2014	Costless Collars	Henry Hub	(190) \$ 4.04 - 4.66
Natural Gas	Apr-Dec 2014	Basis Swaps	Northeast	(89) \$(0.73)
Natural Gas	Apr-Dec 2014	Basis Swaps	MidCon	(220) \$(0.18)
Natural Gas	Apr-Dec 2014	Basis Swaps	Rockies	(110) \$(0.18)
Natural Gas	Apr-Dec 2014	Basis Swaps	West	(55) \$0.10
NGL Ethane	Apr-Dec 2014	Fixed Price Swaps	Mont Belvieu	(3,273) \$0.29
NGL Propane	Apr-Dec 2014	Fixed Price Swaps	Mont Belvieu	(491) \$1.17
NGL Iso Butane	Apr-Dec 2014	Fixed Price Swaps	Mont Belvieu	(655) \$1.37
NGL Normal Butane	Apr-Dec 2014	Fixed Price Swaps	Mont Belvieu	(327) \$1.38
NGL Natural Gasoline	Apr-Dec 2014	Fixed Price Swaps	Mont Belvieu	(1,636) \$2.06
Crude Oil	2015	Swaptions	WTI	(1,750) \$98.54
Natural Gas	2015	Fixed Price Swaps	Henry Hub	(180) \$4.34
Natural Gas	2015	Swaptions	Henry Hub	(50) \$4.38
Natural Gas	2015	Costless Collars	Henry Hub	(50) \$ 4.00 - 4.50

Derivatives primarily related to storage and transportation

Commodity	Period	Contract Type (d)	Location (e)	Notional Volume (b)	Weighted Average Price (f)
Natural Gas	Apr-Dec 2014	Basis Swaps	Multiple	(38) —
Natural Gas	Apr-Dec 2014	Index	Multiple	(151) —
Natural Gas	2015	Basis Swaps	Multiple	(8) —
Natural Gas	2015	Index	Multiple	(115) —
Natural Gas	2016	Index	Multiple	(70) —
Natural Gas	2017+	Index	Multiple	(478) —

Derivatives related to crude oil production are business day average swaps, basis swaps, and swaptions. The derivatives related to natural gas production are fixed price swaps, basis swaps, swaptions and costless collars. The derivatives related to natural gas liquids are fixed price swaps. 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.

(a) 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.

(b) 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.

(c) 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.

	March 31, 2014		December 31, 2013	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production not designated as hedging instruments	\$27	\$77	\$26	\$39
Derivatives related to physical marketing agreements not designated as hedging instruments	15	58	31	83
Total derivatives not designated as hedging instruments	\$42	\$135	\$57	\$122

During the first quarter of 2013, we reclassified \$5 million of net gain on derivatives designated as cash flow hedges from accumulated other comprehensive income (loss) into income. These gains primarily represent realized gains on derivatives designated as hedges of our production and are reflected in natural gas 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 the net gain (loss) related to our energy commodity derivatives.

	Three months ended March 31,	
	2014	2013
	(Millions)	
Gain (loss) from derivatives related to production not designated as hedging instruments (a)	\$(86)	\$(89)
Gain (loss) from derivatives related to physical marketing agreements not designated as hedging instruments (b)	(109)	(5)
Net gain (loss) on derivatives not designated as hedges	\$(195)	\$(94)

(a) Includes payment of \$50 million for settlement of derivatives during the three months ended March 31, 2014 and receipt of \$5 million for the three months ended March 31, 2013.

(b) Includes payment of \$118 million for settlement of derivatives during the three months ended March 31, 2014 and receipt of \$4 million for the three months ended March 31, 2013.

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

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

Offsetting of derivative assets and liabilities

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

	Gross Amount Presented on Balance Sheet (Millions)	Netting Adjustments (a)	Cash Collateral Posted (Received)	Net Amount
March 31, 2014				
Derivative assets with right of offset or master netting agreements	\$42	\$(41)	\$—	\$1
Derivative liabilities with right of offset or master netting agreements	\$(135)	\$41	\$43	\$(51)
December 31, 2013				
Derivative assets with right of offset or master netting agreements	\$57	\$(50)	\$—	\$7
Derivative liabilities with right of offset or master netting agreements	\$(122)	\$50	\$52	\$(20)

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.

- (a) 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 March 31, 2014, we had collateral totaling \$98 million (\$72 million in cash and the remainder in letters of credit) posted to derivative counterparties, which included \$55 million of initial margin to clearinghouses or exchanges to enter into positions and \$43 million of maintenance margin for changes in the fair value of those positions, to support the aggregate fair value of our net \$94 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 \$51 million at March 31, 2014.

Concentration of Credit Risk

Cash equivalents

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

Derivative assets and liabilities

We have a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors.

Risk of loss is impacted by several factors, including credit considerations and the regulatory environment in which a counterparty transacts. We attempt to minimize credit-risk exposure to derivative counterparties and brokers through formal credit policies, consideration of credit ratings from public ratings agencies, monitoring procedures, master netting agreements and collateral support under certain circumstances. Collateral support could include letters of credit, payment under margin agreements and guarantees of payment by credit worthy parties.

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

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2014 and 2013, 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 March 31, 2014, is summarized as follows:

Counterparty Type	Gross Investment Grade (a) (Millions)	Gross Total	Net Investment Grade (a)	Net Total
Financial institutions	\$42	\$42	\$1	\$1
Credit reserves	\$42	42	\$1	1
Credit exposure from derivatives		\$42		\$1

(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 90 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.

Other

At March 31, 2014, we held collateral support of approximately \$69 million (\$12 million in cash and the remainder in letters of credit) related to our gas management sales agreements.

Note 10. 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.

WPX Energy, Inc.

Notes to Consolidated Financial Statements — (Continued)

	Domestic	International (Millions)	Total	
Three months ended March 31, 2014				
Total revenues	\$956	\$31	\$987	
Costs and expenses:				
Lease and facility operating	\$71	\$8	\$79	
Gathering, processing and transportation	106	—	106	
Taxes other than income	41	6	47	
Gas management, including charges for unutilized pipeline capacity	391	—	391	
Exploration	15	—	15	
Depreciation, depletion and amortization	197	10	207	
General and administrative	68	4	72	
Other—net	2	1	3	
Total costs and expenses	\$891	\$29	\$920	
Operating income (loss)	\$65	\$2	\$67	
Interest expense	(29) —	(29)
Interest capitalized	—	—	—	
Investment income and other	2	2	4	
Income (loss) before income taxes	\$38	\$4	\$42	
Three months ended March 31, 2013				
Total revenues	\$595	\$36	\$631	
Costs and expenses:				
Lease and facility operating	\$67	\$8	\$75	
Gathering, processing and transportation	106	1	107	
Taxes other than income	29	6	35	
Gas management, including charges for unutilized pipeline capacity	243	—	243	
Exploration	18	1	19	
Depreciation, depletion and amortization	224	7	231	
General and administrative	69	3	72	
Other—net	6	1	7	
Total costs and expenses	\$762	\$27	\$789	
Operating income (loss)	\$(167) \$9	\$(158)
Interest expense	(26) —	(26)
Interest capitalized	1	—	1	
Investment income and other	2	5	7	
Income (loss) before income taxes	\$(190) \$14	\$(176)
Total assets				
Total assets as of March 31, 2014	\$8,257	\$380	\$8,637	
Total assets as of December 31, 2013	\$8,046	\$383	\$8,429	

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

Note 11. Subsequent Events

On May 6, 2014, we announced an agreement to sell portions of our working interests in certain Piceance Basin wells to Legacy Reserves LP for \$355 million cash, subject to closing adjustments and based on an effective date of January 1, 2014. The parties expect to close the sale during the second quarter 2014. The working interests represent approximately 300 billion cubic feet equivalent of proved reserves, or approximately 6 percent of WPX's year-end 2013 proved reserves. The sale will result in a loss on sale which is currently estimated to be in the range of \$200 million to \$250 million. Upon the closing of this transaction, we expect to have access to approximately 90 percent of our \$1.5 billion Credit Facility Agreement. One of the calculations to determine available borrowing capacity is the requirement to maintain a ratio of net present value of projected future cash flows from proved reserves to Consolidated Indebtedness of at least 1.50 to 1.00.

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 2013 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 months ended March 31, 2014 and 2013:

	Three months ended March 31,	
	2014	2013
Production Sales Data:		
Domestic natural gas (MMcf)	85,988	90,411
Domestic oil (MBbls)	1,738	1,242
Domestic NGLs (MBbls)	1,587	1,907
Domestic combined equivalent volumes (MMcfe) (a)	105,936	109,303
Domestic per day combined equivalent volumes (MMcfe/d)	1,177	1,215
Domestic combined equivalent volumes (MBoe)	17,656	18,217
International combined equivalent volumes (MMcfe) (a)(b)	4,766	4,775
International per day combined equivalent volumes (MMcfe/d)	53	53
International combined equivalent volumes (MBoe) (b)	794	796
Financial Data (millions):		
Total domestic revenues	\$956	\$595
Total international revenues	\$31	\$36
Consolidated operating income (loss)	\$67	\$(158)
Consolidated capital expenditures	\$352	\$271

(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 first quarter 2014 operating results were \$225 million favorable compared to first quarter 2013. The primary favorable impacts to our quarter over quarter operating results include \$160 million higher product sales, a \$152 million increase in gas management margin and \$24 million decrease in depreciation, depletion and amortization. Offsetting the favorable items was a \$104 million increase in the loss on derivatives related to gas management.

Outlook

In 2014, we will continue our focus of growing our oil production and developing oil reserves, primarily those located in the Williston Basin and the Gallup Sandstone in the San Juan Basin. More than half of our planned 2014 capital expenditures are in domestic oil properties which includes a goal of 62 oil wells (gross) in the Williston Basin, an increase of 25 percent versus 2013, and 29 oil wells (gross) in the Gallup Sandstone which would nearly double 2013 activity.

We will also continue to focus our natural gas drilling effort in the Piceance Basin because of our scale and efficiency of that operation combined with significant infrastructure already in place. We have a goal of increasing our natural gas volumes over current production in the Piceance Basin by planning to deploy an average of nine drilling rigs in the Piceance Basin for 2014 which includes drilling focused on the Niobrara Shale discussed below. Our drilling program in the Appalachian Basin will be limited to completions in 2014. We may resume development in 2015.

We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities and negotiating cost savings on vendor contracts. Additionally, we are undertaking extensive review of our general and administrative costs and services.

As previously disclosed in our Form 10-K, we had begun the process of forming a Master Limited Partnership (“MLP”) to which we would contribute mature, natural gas properties located in the Piceance Basin. In early 2014, an alternative transaction for these assets was considered. On May 6, 2014, we announced an agreement to sell portions of our working interests in certain Piceance Basin wells to Legacy Reserves LP (“Legacy”) for \$355 million cash, subject to closing adjustments and based on an effective date of January 1, 2014. The parties expect to close the sale during the second-quarter 2014. The working interests represent approximately 300 billion cubic feet equivalent of proved reserves, or approximately 6 percent of WPX’s year-end 2013 proved reserves. The sale will result in a loss on sale which is currently estimated to be in the range of \$200 million to \$250 million. The terms of the sale also provide us with 10 percent ownership in a newly created class of incentive distribution rights (“IDR”) with Legacy. WPX has the opportunity to increase its ownership in the units to 30 percent, contingent upon completing other transactions in the future. This would include the potential to partner on third-party acquisitions. Additionally, we are evaluating other transactions that would monetize certain of our assets and enable us to redeploy the sales proceeds in areas where there is an opportunity for a higher return.

Approximately 12 percent of our estimated annual capital spending in 2014 will be for exploratory activities, primarily for further delineation of our Niobrara Shale discovery in the Piceance Basin. We are also in the process of drilling test wells in other new areas. We will also continue to evaluate the purchase of leasehold in these and other areas. Our initial Niobrara Shale discovery well in the Piceance Basin produced 2.2 billion cubic feet of natural gas production in the first year of operation. We drilled four additional wells in 2013, two of which are producing, one that is a vertical test well and one that will be plugged due to a casing issue in the lateral section before completion began. WPX is planning to re-drill another well from this same location later this year that will parallel the original lateral by a couple hundred feet. Initial drilling thus far has validated the existence of a highly pressured continuous gas accumulation capable of producing pipeline-quality gas. Future drilling will focus on driving down costs while optimizing completion techniques. We plan to double our Niobrara delineation drilling in 2014 with up to 10 wells expected and we also initiated 3-D seismic work in the Piceance Valley to aid in the delineation. This activity will provide 70 percent seismic coverage of our Piceance Valley acreage.

We anticipate our total capital spending in 2014 will be up to \$1.5 billion. The execution of transactions to monetize certain of our assets as previously mentioned is an important component to achieving the necessary capital to fund our spending program. The previously discussed transaction with Legacy will provide a significant portion of funding for our capital program that was not provided by cash flow from operations. If we are unable to successfully execute on additional assets sales, we may reduce our capital spending or make additional borrowings on our revolver. Through March 31, 2014, our capital expenditures totaled \$352 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 Williston Basin oil play position, Gallup Sandstone oil play and liquids-rich basins (primarily Piceance Basin) with high concentrations of NGLs;
- Fully delineating 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;
- Lower than expected proceeds from asset sales;

Counterparty credit and performance risk;
General economic, financial markets or industry downturn;
Changes in the political and regulatory environments;
Increase in the cost of, or shortages or delays in the availability of, drilling rigs and equipment supplies, skilled labor or transportation;

Decreased drilling success; and
Unavailability of capital.

Currently the forward natural gas prices for the remainder of 2014 are higher than our realized prices for 2013. However, forward natural gas and oil prices for 2015 and after are lower than the 2014 prices. Changes in the forward prices will be considered as we proceed with our 2014 capital program. Additionally, if forward natural gas prices were to decline by 6 to 8 percent or forward oil prices were to decline by 11 to 13 percent as compared to the forward prices at December 31, 2013, we would need to review a substantial portion of the producing properties net book value for impairment. With the exception of potential impairments, we continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we utilize master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements.

Commodity Price Risk Management

To manage the commodity price risk and volatility of owning producing gas and oil properties, we enter into derivative contracts for a portion of our future production. We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. For the remainder of 2014 and 2015, 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	Apr - Dec 2014		2015	
	Volume (BBtu/d)	Weighted Average Price (\$/MMBtu)	Volume (BBtu/d)	Weighted Average Price (\$/MMBtu)
Fixed-price—Henry Hub	315	\$4.19	182	\$4.35
Swaptions—Henry Hub	50	\$4.24	50	\$4.38
Collars—Henry Hub	190	\$ 4.04 - 4.66	50	\$ 4.00 - 4.50
Basis swaps—Northeast	89	\$(0.73)	—	\$—
Basis swaps—Mid-Continent	265	\$(0.16)	—	\$—
Basis swaps—West	71	\$0.13	—	\$—
Basis swaps—Rockies	139	\$(0.15)	—	\$—

Crude Oil	Apr - Dec 2014		2015	
	Volume (Bbls/d)	Weighted Average Price (\$/Bbl)	Volume (Bbls/d)	Weighted Average Price (\$/Bbl)
Fixed-price—WTI	12,750	\$94.62	3,500	\$93.33
Swaptions—WTI	—	\$—	5,250	\$95.06
Basis swaps—Brent	2,978	\$9.64	—	\$—

Natural Gas Liquids	Apr - Dec 2014	
	Volume (Bbls/d)	Weighted Average Price (\$/Gal)
Fixed-price—Mont Belvieu Ethane	3,273	\$0.29
Fixed-price—Mont Belvieu Propane	491	\$1.17
Fixed-price—Mont Belvieu Iso Butane	655	\$1.37
Fixed-price—Mont Belvieu Normal Butane	327	\$1.38
Fixed-price—Mont Belvieu Natural Gasoline	1,636	\$2.06

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 an obligation, which expires in November 2014, to deliver on a firm basis 200,000 MMBtu/d of natural gas at monthly index pricing to a buyer at the White River Hub (Greasewood-Meeker, CO), which is a major market hub exiting the Piceance Basin. However, the price received is based on a Northeast index and was less than the index price in the Rockies in 2014 and 2013. Our interests in the Piceance Basin hold sufficient reserves to meet this obligation.

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 as well as coal bed methane reserves in the Piceance, Williston, San Juan, Powder River, 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.

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended March 31, 2014 2013 (Millions)		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change	
Domestic revenues:					
Natural gas sales	\$379	\$263	\$116	44	%
Oil and condensate sales	149	111	38	34	%
Natural gas liquid sales	61	53	8	15	%
Total product revenues	589	427	162	38	%
Gas management	561	261	300	115	%
Net gain (loss) on derivatives not designated as hedges	(195) (94) (101) (107)%
Other	1	1	—	—	%
Total domestic revenues	\$956	\$595	\$361	61	%
Total international revenues	\$31	\$36	\$(5) (14)%
Total revenues	\$987	\$631	\$356	56	%

Domestic Revenues

Significant variances in the respective line items of domestic revenues are comprised of the following: \$116 million increase in natural gas sales is primarily due to \$129 million related to higher sales prices partially offset by \$13 million related to lower production sales volumes. The decrease in our production sales volumes is due to the level of development of our natural gas reserves in the low natural gas price environment experienced over the past two years. We 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. The following table reflects natural gas production prices and volumes for the three months ended March 31, 2014 and 2013:

	Three months ended March 31, 2014 2013	
Natural gas sales (per Mcf) (a)	\$ 4.40	\$ 2.90
Impact of net cash received (paid) related to settlement of derivatives (per Mcf) (b)	(0.52)) 0.01
Natural gas net price including derivative settlements (per Mcf)	\$ 3.88	\$ 2.91
Natural gas production sales volumes (MMcf)	85,988	90,411
Per day natural gas production sales volumes (MMcf/d)	955	1,005

(a) Includes \$0.05 per Mcf impact of net cash received on derivatives designated as hedges for the three months ended March 31, 2013.

(b) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations. \$38 million increase in oil and condensate sales reflects increased production sales volumes for the three months ended March 31, 2014 and 2013, respectively. The increase in production sales volumes primarily relate to increased production in the Williston Basin where the volumes were 15.6 MBbls per day for the first three months 2014 compared to 11.5 MBbls per day for the same period in 2013. The San Juan Basin also had production of 1.7 MBbls per day for 2014 related to the Gallup Sandstone development. The following table reflects oil and condensate production prices and volumes for first quarter 2014 and 2013:

	Three months ended March 31, 2014 2013	
Oil sales (per barrel)	\$ 86.24	\$ 89.77
Impact of net cash received (paid) related to settlement of derivatives (per barrel) (a)	(2.30)) 4.03
Oil net price including derivative settlements (per barrel)	\$ 83.94	\$ 93.80
Oil and condensate production sales volumes (MBbls)	1,738	1,242
Per day oil and condensate production sales volumes (MBbls/d)	19.3	13.8

(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

\$8 million increase in natural gas liquids sales reflects higher NGL prices for 2014 compared to 2013. The increased average per barrel price for natural gas liquids partially reflects a change in the composition of the barrel, as noted in the table below, due to lower ethane recovery rates. The following table reflects NGL production prices and volumes for the three months ended March 31, 2014 and 2013:

	Three months ended March 31,	
	2014	2013
NGL sales (per barrel)	\$38.27	\$28.21
Impact of net cash received (paid) related to settlement of derivatives (per barrel) (a)	(0.48)	—
NGL net price including derivative settlements (per barrel)	\$37.79	\$28.21
NGL production sales volumes (MBbls)	1,587	1,907
Per day NGL production sales volumes (MBbls/d)	17.6	21.2

(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

The following table summarizes the composition of the Piceance NGL barrel for the three months ended March 31, 2014 and 2013:

	Three months ended March 31,			
	2014		2013	
	% of barrel	\$/gallon	% of barrel	\$/gallon
Ethane	32	% \$0.30	44	% \$0.26
Propane	32	% \$1.28	26	% \$0.84
Iso-Butane	9	% \$1.40	8	% \$1.59
Normal Butane	8	% \$1.37	7	% \$1.52
Natural Gasoline	19	% \$2.11	15	% \$2.14

\$300 million increase in gas management revenues primarily due to higher average prices on physical natural gas sales as well as higher oil sales volumes. The higher natural gas prices reflect the benefit of an increase in natural gas prices at sales points utilizing contracted pipeline capacity in the Northeast. The increase in the sales price was greater than the increase in the purchase price as reflected in the \$148 million increase in related gas management costs and expenses, discussed below. The increase in gas management revenues was also partially offset by a \$107 million increase in net loss related to derivatives associated with gas management activities which are included in net gain (loss) on derivatives not designated as hedges, a separate line on the income statement, and is discussed below. \$101 million unfavorable change in net gain (loss) on derivatives not designated as hedges primarily reflects \$122 million unfavorable change realized on gas management derivatives as well as \$55 million unfavorable change realized on derivatives for our production, primarily natural gas and crude. The realized unfavorable changes were partially offset by a \$59 million decrease in unrealized losses on derivatives related to production, primarily natural gas, and a \$17 million favorable change in the unrealized portion of gas management derivatives.

International Revenues

International revenues decreased primarily due to lower oil sales and the absence in 2014 of significant revenues realized from the government hydrocarbon subsidy program in Argentina.

Cost and operating expense and operating income (loss) analysis

	Three months ended March 31, 2014 (Millions)	2013	Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change
Domestic costs and expenses:				
Lease and facility operating	\$71	\$67	\$(4)	(6)%
Gathering, processing and transportation	106	106	—	—%
Taxes other than income	41	29	(12)	(41)%
Gas management, including charges for unutilized pipeline capacity	391	243	(148)	(61)%
Exploration	15	18	3	17%
Depreciation, depletion and amortization	197	224	27	12%
General and administrative	68	69	1	1%
Other—net	2	6	4	67%
Total domestic costs and expenses	\$891	\$762	\$(129)	(17)%
International costs and expenses:				
Lease and facility operating	\$8	\$8	\$—	—%
Gathering, processing and transportation	—	1	1	100%
Taxes other than income	6	6	—	—%
Exploration	—	1	1	100%
Depreciation, depletion and amortization	10	7	(3)	(43)%
General and administrative	4	3	(1)	(33)%
Other—net	1	1	—	—%
Total international costs and expenses	\$29	\$27	\$(2)	(7)%
Total costs and expenses	\$920	\$789	\$(131)	(17)%
Domestic operating income (loss)	\$65	\$(167)	\$232	NM
International operating income	\$2	\$9	\$(7)	(78)%

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:

\$4 million increase in lease and facility operating expense primarily relates to the impact of increased Williston and San Juan Basin production in relation to our overall portfolio, along with higher workover expense in other basins.

Lease and facility operating expense averaged \$0.67 per Mcfe for the three months ended March 31, 2014 compared to \$0.61 for the same period in 2013 and the increase partially reflects the growth of our oil properties in the Williston and San Juan basins in relation to the total.

Gathering, processing and transportation charges averaged \$1.00 per Mcfe for 2014 and \$0.98 per Mcfe for 2013.

\$12 million increase in taxes other than income primarily relates to the increase in product revenues for 2014 compared to 2013. Taxes other than income averaged \$0.39 per Mcfe for the first three months of 2014 compared to \$0.27 per Mcfe for the same period in 2013.

\$148 million increase in gas management expenses, primarily due to higher average prices on physical natural gas cost of sales as well as higher oil purchase volumes. Also included in gas management expenses are \$16 million and \$13 million for the three months ended March 31, 2014 and 2013, respectively, for unutilized pipeline capacity.

\$27 million decrease in depreciation, depletion and amortization primarily due to lower production volumes in 2014 compared to 2013 and the impact of impairments taken in 2013 in the Appalachia and Powder River Basins. During the three months ended March 31, 2014, our depreciation, depletion and amortization averaged \$1.86 per Mcfe compared to an average \$2.04 per Mcfe for the same period in 2013.

General and administrative expense averaged \$0.65 per Mcfe compared to \$0.62 per Mcfe for the three months ended March 31, 2014 and 2013, respectively.

Consolidated results below operating income (loss)

	Three months ended March 31, 2014 2013 (Millions)		Favorable (Unfavorable) \$ Change	Favorable (Unfavorable) % Change
Consolidated operating income (loss)	\$67	\$(158)) \$225	NM
Interest expense	(29)) (26)) (3)) (12) %
Interest capitalized	—	1	(1)) (100) %
Investment income and other	4	7	(3)) (43) %
Income (loss) before income taxes	42	(176)) 218	NM
Provision (benefit) for income taxes	23	(63)) (86)) NM
Net income (loss)	19	(113)) 132	NM
Less: Net income (loss) attributable to noncontrolling interests	1	3	(2)) (67) %
Net income (loss) attributable to WPX Energy, Inc.	\$18	\$(116)) \$134	NM

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

The increase in interest expense primarily relates to a higher amount outstanding on our revolver for the three months ended March 31, 2014 compared to the same period in 2013.

Provision for income taxes changed unfavorably due to pre-tax income in 2014 compared to pre-tax loss in 2013. See Note 6 for a discussion of the effective tax rates compared to the federal statutory rate for both periods. Also, we recorded an additional \$9 million of deferred tax expense in the first quarter to accrue for the impact of new legislation. Tax reform legislation was enacted by the state of New York on March 31, 2014 and has an impact on us as a result of our marketing activities in the state. Key components of this reform measure relative to our business include water's edge unitary combined reporting, single sales factor apportionment and the application of "economic nexus" to corporations with sales of \$1 million or more to New York customers. Generally accepted accounting principles require that we adjust our state deferred tax liability for the estimated impact of this legislation in the period of enactment.

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 2014 are expected cash flows from operations, proceeds from monetization of assets and additional 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 2014.

We note the following assumptions for 2014:

• Our capital expenditures, including international, are estimated to be up to \$1.5 billion in 2014, 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. Included in our cash and cash equivalents at March 31, 2014 is \$42 million related to our international operations. Potential risks associated with our planned levels of liquidity and the planned capital and investment expenditures discussed above include:

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

• Lower than expected proceeds from asset sales;

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

• Significantly lower than expected capital expenditures could result in the loss of undeveloped 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 2014. 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

	Three months ended March 31, 2014 2013 (Millions)	
Net cash provided (used) by:		
Operating activities	\$206	\$144
Investing activities	(354)) (271)
Financing activities	112	87
Increase (decrease) in cash and cash equivalents	\$(36)) \$(40)
Operating activities		

Our net cash provided by operating activities for the three months ended March 31, 2014 increased from the same period in 2013 primarily due to the increase in our operating results offset by unfavorable changes in working capital, primarily margin deposits and customer margin deposits payable.

Investing activities

Expenditures for domestic drilling and completion were \$268 million and \$232 million for the three months ended March 31, 2014 and 2013, respectively. Domestic land acquisitions were \$47 million during the first quarter of 2014. In addition, expenditures for international were \$21 million and \$12 million for the three months ended March 31, 2014 and 2013, respectively.

Financing activities

Net cash provided by financing activities in 2014 and 2013 primarily relates to borrowings under our revolving credit facility agreement (see Note 5 of Notes to Consolidated Financial Statements) made to partially fund capital expenditures for the first quarters of 2014 and 2013.

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 March 31, 2014 or at December 31, 2013.

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 three months of 2014.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of natural gas, oil and natural gas liquids as well as other market factors, such as market volatility and energy commodity price correlations. We are exposed to these risks in connection with our owned energy-related assets, our long-term energy-related contracts and our marketing trading activities. We manage the risks associated with these market fluctuations using various derivatives and nonderivative energy-related contracts. The fair value of derivative contracts is subject to many factors, including changes in energy commodity market prices, the liquidity and volatility of the markets in which the contracts are transacted and changes in interest rates. See Notes 8 and 9 of Notes to Consolidated Financial Statements.

We measure the risk in our portfolios using a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. Our value-at-risk model uses a Monte

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

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

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

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net liability of \$1 million at both March 31, 2014 and December 31, 2013. The value at risk for contracts held for trading purposes was zero at March 31, 2014 and less than \$1 million at December 31, 2013.

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 liability of \$92 million and \$64 million at March 31, 2014 and December 31, 2013, respectively.

The value at risk for derivative contracts held for nontrading purposes was \$17 million at March 31, 2014, and \$19 million at December 31, 2013. During the last 12 months, our value at risk for these contracts ranged from a high of \$19 million to a low of \$12 million.

Item 4. Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act) (“Disclosure Controls”) or our internal 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.

First-Quarter 2014 Changes in Internal Controls

There have been no changes during the first quarter of 2014 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 7 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, 2013, includes certain risk factors that could materially affect our business, financial condition or future results. Those risk factors have not materially changed as of March 31, 2014.

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 | Amended and Restated Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on March 21, 2014) |
| 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.

Edgar Filing: WPX ENERGY, INC. - Form 10-Q

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 (1)
10.14*	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (1)
10.15*	Form of Stock Option Agreement between WPX Energy, Inc. and Section 16 Executive Officers (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)
10.18	Agreement, dated December 17, 2013, between WPX Energy, Inc. and Taconic Capital Advisors LP (incorporated herein by reference to Exhibit 99.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 18, 2013)
10.19	Retirement Agreement, dated December 16, 2013, between WPX Energy, Inc. and Ralph A. Hill (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 17, 2013)
10.20	Severance Agreement, dated February 18, 2014, between WPX Energy, Inc. and Neal A. Buck (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s current report on Form 8-K filed with the SEC on February 19, 2014) (1)
10.21	Employment Agreement, dated April 29, 2014, between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on 8-K filed with the SEC on May 2, 2014) (1)
10.22	Form of Nonqualified Stock Option Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current Report on 8-K filed

with the SEC on May 2, 2014) (1)

- 10.23 Form of 2014 Time-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current Report on 8-K filed with the SEC on May 2, 2014) (1)
- 10.24 Form of 2014 Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current Report on 8-K filed with the SEC on May 2, 2014) (1)
- 10.25 Form of Time-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.5 to WPX Energy, Inc.'s Current Report on 8-K filed with the SEC on May 2, 2014) (1)
- 10.26 Form of Performance-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.6 to WPX Energy, Inc.'s Current Report on 8-K filed with the SEC on May 2, 2014) (1)

Exhibit No.	Description
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

(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
Senior Vice President and Chief Financial
Officer (Principal Accounting Officer)

Date: May 7, 2014