WPX ENERGY, INC.
Form 10-Q
November 05, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-Q
(Mark One)
R QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 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)	74172-0172 (Zip Code)

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

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

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes R 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 R 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 R	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 R

The number of shares outstanding of the registrant's common stock at November 4, 2014 were 203,370,114.

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

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

- Amounts and nature of future capital expenditures;
- Expansion and growth of our business and operations;
- Financial condition and liquidity;
- Business strategy;
- Estimates of proved gas and oil reserves;
- Reserve potential;
- Development drilling potential;
- Cash flow from operations or results of operations;
- Acquisitions or divestitures;

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- 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)

	September 30, 2014	December 31, 2013
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$65	$ 99
Accounts receivable, net of allowance of $6 million at September 30, 2014 and $7 million at December 31, 2013	465	536
Deferred income taxes	31	49
Derivative assets	107	50
Inventories	70	71
Margin deposits	52	71
Assets classified as held for sale	184	1
Other	31	45
Total current assets	1,005	922
Investments	135	129
Properties and equipment (successful efforts method of accounting)	11,993	12,519
Less—accumulated depreciation, depletion and amortization	(4,956)	(5,445)
Properties and equipment, net	7,037	7,074
Derivative assets	22	7
Other noncurrent assets	45	297
Total assets	$8,244	$ 8,429
Liabilities and Equity		
Current liabilities:		
Accounts payable	$699	$ 652
Accrued and other current liabilities	175	187
Liabilities associated with assets held for sale	50	3
Customer margin deposits payable	14	55
Deferred income taxes	1	—
Derivative liabilities	72	110
Total current liabilities	1,011	1,007
Deferred income taxes	713	788
Long-term debt	2,047	1,916
Derivative liabilities	15	12
Asset retirement obligations	199	310
Other noncurrent liabilities	57	186
Contingent liabilities and commitments (Note 8)		
Equity:		
Stockholders’ equity:		
Preferred stock (100 million shares authorized at $0.01 par value; no shares issued)	—	—
Common stock (2 billion shares authorized at $0.01 par value; 203.4 million shares issued at September 30, 2014 and 201 million shares issued at December 31, 2013)	2	2
Additional paid-in-capital	5,556	5,516
Accumulated deficit	(1,463)	(1,408)
Accumulated other comprehensive income (loss)	(1)	(1)
Total stockholders’ equity	4,094	4,109

Noncontrolling interests in consolidated subsidiaries	108	101
Total equity	4,202	4,210
Total liabilities and equity	$ 8,244	$ 8,429

See accompanying notes.

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
	(Millions, except per-share amounts)			
Revenues:				
Product revenues:				
Natural gas sales	$207	$210	$798	$699
Oil and condensate sales	240	183	638	473
Natural gas liquid sales	54	57	170	169
Total product revenues	501	450	1,606	1,341
Gas management	145	176	937	642
Net gain (loss) on derivatives not designated as hedges (Note 10)	148	(15)	(64)	(31)
Other	—	5	6	16
Total revenues	794	616	2,485	1,968
Costs and expenses:				
Lease and facility operating	73	70	208	196
Gathering, processing and transportation	82	88	250	264
Taxes other than income	40	33	121	95
Gas management, including charges for unutilized pipeline capacity	164	201	788	666
Exploration (Note 4)	29	21	101	59
Depreciation, depletion and amortization	213	230	627	662
Impairment of costs of acquired unproved reserves (Note 4)	—	19	—	19
Loss on sale of working interests in the Piceance Basin	1	—	196	—
General and administrative	75	67	219	209
Other—net	3	1	9	10
Total costs and expenses	680	730	2,519	2,180
Operating income (loss)	114	(114)	(34)	(212)
Interest expense	(31)	(28)	(88)	(82)
Interest capitalized	1	1	1	1
Investment income and other	5	4	12	17
Income (loss) from continuing operations before income taxes	89	(137)	(109)	(276)
Provision (benefit) for income taxes	28	(29)	(31)	(79)
Income (loss) from continuing operations	61	(108)	(78)	(197)
Income (loss) from discontinued operations	5	(8)	30	(10)
Net income (loss)	66	(116)	(48)	(207)
Less: Net income (loss) attributable to noncontrolling interests	4	(2)	7	5
Net income (loss) attributable to WPX Energy, Inc.	$62	$(114)	$(55)	$(212)
Amounts attributable to WPX Energy, Inc. (Note 3):				
Basic and diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$0.28	$(0.53)	$(0.42)	$(1.01)
Income (loss) from discontinued operations	0.02	(0.04)	0.15	(0.05)
Net income (loss)	$0.30	$(0.57)	$(0.27)	$(1.06)
Basic weighted-average shares (millions)	203.3	200.7	202.5	200.3
Diluted weighted-average shares (millions)	207.5	200.7	202.5	200.3

See accompanying notes.

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
	(Millions)			
Net income (loss) attributable to WPX Energy, Inc.	$62	$(114)	$(55)	$(212)
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.	$62	$(114)	$(55)	$(215)

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

See accompanying notes.

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

	WPX Energy, Inc., Stockholders					Noncontrolling	
	Common Stock	Additional Paid-In-Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Interests in Consolidated Subsidiaries (a)	Total Equity
	(Millions)						
Balance at December 31, 2013	$2	$5,516	$ (1,408)	$ (1)	$ 4,109	$ 101	$4,210
Comprehensive income (loss):							
Net income (loss)	—	—	(55)	—	(55)	7	(48)
Other comprehensive loss	—	—	—	—	—	—	—
Comprehensive income (loss)							(48)
Stock based compensation	—	40	—	—	40	—	40
Contribution from noncontrolling interest						—	—
Balance at September 30, 2014	$2	$5,556	$ (1,463)	$ (1)	$ 4,094	$ 108	$4,202

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

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

	Nine months ended September 30,	
	2014	2013
	(Millions)	
Operating Activities		
Net income (loss)	$(48)	$(207)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	638	699
Deferred income tax provision (benefit)	(55)	(67)
Provision for impairment of properties and equipment (including certain exploration expenses)	95	64
Amortization of stock-based awards	26	24
(Gain) loss on sale of assets	195	(5)
Cash provided (used) by operating assets and liabilities:		
Accounts receivable	71	55
Inventories	1	(5)
Margin deposits and customer margin deposit payable	(22)	(2)
Other current assets	16	(11)
Accounts payable	(15)	(5)
Accrued and other current liabilities	(22)	(32)
Changes in current and noncurrent derivative assets and liabilities	(106)	18
Other, including changes in other noncurrent assets and liabilities	5	(6)
Net cash provided by operating activities	779	520
Investing Activities		
Capital expenditures (a)	(1,325)	(843)
Proceeds from sale of assets (b)	389	10
Other	(3)	(3)
Net cash used in investing activities	(939)	(836)
Financing Activities		
Proceeds from common stock	15	4
Proceeds from long-term debt	500	—
Borrowings on credit facility	1,451	605
Payments on credit facility	(1,816)	(335)
Payments for debt issuance costs	(6)	—
Other	(12)	(1)
Net cash provided by financing activities	132	273
Net increase (decrease) in cash and cash equivalents	(28)	(43)
Effect of exchange rate changes on cash and cash equivalents	(6)	(2)
Cash and cash equivalents at beginning of period	99	153
Cash and cash equivalents at end of period	$65	$108

(a) Increase to properties and equipment	$(1,389)	$(864)
Changes in related accounts payable and accounts receivable	64	21
Capital expenditures	$(1,325)	$(843)

(b) Proceeds in 2014 primarily relate to the sale of a portion of our working interests in the Piceance Basin and are subject to post-closing adjustments.
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 September 30, 2014, results of operations for the three and nine months ended September 30, 2014 and 2013, changes in equity for the nine months ended September 30, 2014 and cash flows for the nine months ended September 30, 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.
During the third quarter of 2014, we signed an agreement for the sale of our remaining mature, coalbed methane holdings in the Powder River Basin in Wyoming. As a result, we have reported the results of operations of the Powder River Basin as discontinued operations (see Note 2).
Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations.
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 primarily located in Colorado, New Mexico and North Dakota in the United States. We specialize in development and production from tight-sands and shale formations and coalbed methane reserves in the Piceance, Williston and San Juan Basins. We also have operations and interests in the Appalachian and Green River Basins located in Pennsylvania and Wyoming. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation, 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. See Note 12 for a discussion of a recently announced agreement to sell our international interests.
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".
Recently Issued Accounting Standards
In April 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2014-08, Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity that raised the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other material disposal transactions that do not meet the revised definition of discontinued operations. Under the updated standard, a disposal of a component or group of components of an entity is required to be reported as discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component or group of components of the entity (1) has been disposed of by a sale, (2) has been disposed of other than by sale or (3) is classified as held for sale. This accounting standards update is effective for annual periods beginning on or after December 15, 2014 and is applied prospectively. Early adoption is permitted but only for disposals (or classifications that are held for sale) that have not been reported in financial statements previously issued or available for use. We have elected to early adopt this standard during the third quarter of 2014. As such, any disposals which meet the criteria above are reported as discontinued operations (see Note 2).
In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. The core principles of the guidance in ASU 2014-09 are that an entity should recognize revenue to depict the transfer of promised goods or

services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 is effective for annual reporting periods beginning after December 15, 2016, including interim periods

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

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

Note 2. Discontinued Operations

During the third quarter of 2014, our management signed an agreement to sell our remaining mature, coalbed methane holdings in the Powder River Basin for $155 million, subject to closing adjustments such as net revenues from effective date to closing date. The transaction is expected to close in the fourth quarter of 2014. The mid-year proved reserves in the basin were 222 Bcfe and third quarter production was 146 MMcf per day, which includes operated and non-operated working interests in approximately 5,000 wells. The Company has not actively drilled in the basin since 2011.

Summarized Results of Discontinued Operations

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
	(Millions)			
Revenues	$41	$42	$151	$136
Costs and expenses:				
Lease and facility operating	11	12	32	34
Gathering, processing and transportation	16	18	51	60
Taxes other than income	4	3	12	12
Exploration	—	—	—	1
Depreciation, depletion and amortization	3	11	11	37
General and administrative	1	1	3	5
Other—net	—	9	—	8
Total costs and expenses	35	54	109	157
Operating income (loss)	6	(12)	42	(21)
Interest capitalized	—	1	1	3
Investment income and other	1	—	4	3
Income (loss) from discontinued operations before income taxes	7	(11)	47	(15)
Provision (benefit) for income taxes	2	(3)	17	(5)
Income (loss) from discontinued operations	$5	$(8)	$30	$(10)

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

Assets and Liabilities in the Consolidated Balance Sheet Attributable to Discontinued Operations

	September 30, 2014	December 31, 2013 (a)
	(Millions)	
Assets		
Current assets:		
Inventories	$1	$1
Total current assets	1	1
Investments	18	16
Properties and equipment (successful efforts method of accounting)	176	167
Less—accumulated depreciation, depletion and amortization	(11)	—
Properties and equipment, net	165	167
Total assets classified as held for sale (a)	$184	$184
Liabilities and Equity		
Current liabilities:		
Accrued and other current liabilities	$3	$3
Total current liabilities	3	3
Asset retirement obligations	47	48
Total liabilities associated with assets held for sale (a)	$50	$51

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(a) Noncurrent assets and liabilities as of December 31, 2013 that are attributable to discontinued operations have been reflected in other noncurrent assets and liabilities on the Consolidated Balance Sheet as of December 31, 2013.

Cash Flows Attributable to Discontinued Operations
Excluding taxes and changes to working capital related to Powder River, total cash provided by operating activities related to discontinued operations was $58 million and $23 million for the nine months ended September 30, 2014 and 2013, respectively. Total cash used in investing activities related to discontinued operations was $7 million and $3 million for the nine months ended September 30, 2014 and 2013, respectively.

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

	Three months ended September 30, 2014	Three months ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
	(Millions, except per-share amounts)			
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$57	$(106)	$(85)	$(202)
Basic weighted-average shares	203.3	200.7	202.5	200.3
Effect of dilutive securities (a):				
Nonvested restricted stock units and awards	3.2	—	—	—
Stock options	1.0	—	—	—
Diluted weighted-average shares	207.5	200.7	202.5	200.3
Earnings (loss) per common share:				
Basic	$0.28	$(0.53)	$(0.42)	$(1.01)
Diluted	$0.28	$(0.53)	$(0.42)	$(1.01)

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(a) For the nine months ended September 30, 2014, 2.8 million weighted-average nonvested restricted stock units and awards and 1.0 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.

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

for the nine months ended September 30, 2014. For the three and nine months ended September 30, 2013, 2.7 million and 2.3 million, respectively, weighted-average nonvested restricted stock units and awards and 1.2 million and 1.1 million, respectively, 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 and nine months ended September 30, 2013.

The table below includes information related to stock options that were outstanding as of September 30, 2013 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the third quarter weighted-average market price of our common shares.

	September 30,	
	2014	2013
Options excluded (millions)	—	0.4
Weighted-average exercise price of options excluded	$—	$20.23
Exercise price range of options excluded	—	$19.95 - $20.97
Third quarter weighted-average market price	$23.67	$19.23

Note 4. Asset Sale, Impairments and Exploration Expenses

Asset Sale

In May 2014, we agreed to the sale of 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 terms of the sale also provided us with a 10 percent ownership in a newly created class of incentive distribution rights (“IDR”) of Legacy. The working interests represent approximately 300 billion cubic feet of proved reserves, or approximately 6 percent of WPX’s year-end 2013 proved reserves. Production related to these working interests for January through May approximated 70 MMcfe/day of our production. The sale closed at the beginning of June and we received proceeds of $337 million which were subject to post closing adjustments including settlement of production for April and May. We estimate the amount to be remitted to Legacy in the fourth quarter will be $12 million. Based on an estimated total value received of $329 million, which represents estimated final cash proceeds and an estimated fair value of the IDRs, we recorded a $195 million loss on the sale in second quarter 2014. In the third quarter of 2014, we recorded an additional loss on sale of $1 million related to this transaction.

Impairment of Cost of Acquired Unproved Reserves

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

Exploration Expenses

The following table presents a summary of exploration expenses.

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
	(Millions)			
Geologic and geophysical costs	$1	$6	$8	$14
Dry hole costs and impairments of exploratory area well costs	7	—	25	2
Unproved leasehold property impairment, amortization and expiration	21	15	68	43
Total exploration expenses	$29	$21	$101	$59

Dry hole costs and impairments of exploratory area well costs for the three and nine months ended September 30, 2014 includes $6 million and $16 million, respectively, of impairments of well costs in exploratory areas in the United States where management has determined to cease exploratory activities. The remaining amount represents impairment of international well costs and dry hole costs associated with exploratory wells in the United States where hydrocarbons were not detected. As of September 30, 2014, our total domestic capitalized well costs associated with our exploratory areas, including the Niobrara Shale in the Piceance Basin, totaled approximately $70 million.

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

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

Note 5. Inventories and Properties and Equipment

Inventories

	September 30, 2014	December 31, 2013
	(Millions)	
Natural gas in underground storage	$14	$13
Crude oil production in transit	3	10
Material, supplies and other	53	48
	$70	$71

Properties and Equipment

During the third quarter of 2014, we purchased oil and natural gas properties in the San Juan Basin for $150 million. The properties purchased included both producing wells and undeveloped locations. Approximately $50 million of the purchase price was allocated to proved producing properties and the remainder to proved undeveloped or unproved leasehold within properties and equipment. The purchase price is subject to post closing adjustments and therefore, the allocation is preliminary. The purchase is included within our capital expenditures on the Consolidated Statement of Cash Flows.

Also during the third quarter of 2014, we closed an agreement to farmout a portion of our Trail Ridge properties in the Piceance Basin with TRDC LLC, a subsidiary of G2X Energy. We received $50 million in cash for 49 percent of our working interests in approximately 100 proved developed wells and certain incurred drilling costs. TRDC LLC has committed to a $170 million drilling carry on nearly 400 future wells and will make additional investments for its 49 percent working interest.

Asset Retirement Obligation

A rollforward of our asset retirement obligations for the current year is presented below.

	Nine months ended September 30, 2014
	(Millions)
Balance, January 1, 2014	$313
Liabilities incurred	17
Liabilities settled	(1)
Liabilities associated with assets sold	(65)
Estimate revisions (a)	(78)
Accretion expense	16
Balance, September 30, 2014	202
Amount reflected as current	$3

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(a) Estimate revisions are primarily associated with decreases in anticipated future plug and abandonment costs.

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

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

	September 30, 2014	December 31, 2013
	(Millions)	
5.250% Senior Notes due 2017	$400	$400
6.000% Senior Notes due 2022	1,100	1,100
5.250% Senior Notes due 2024	500	—
Credit facility agreement	45	410
Apco	6	8
Other	1	1
Total debt	$2,052	$1,919
Less: Current portion of long-term debt	5	3
Total long-term debt	$2,047	$1,916

Senior Notes
In September 2014, we issued $500 million in face value 5.25% Senior Notes due 2024 (the "Notes") pursuant to our automatic shelf registration statement on Form S-3 filed with the Securities and Exchange Commission. The Notes were issued under an indenture, as supplemented by a supplemental indenture, each between us and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Indenture"). The net proceeds from the offering of the Notes were approximately $494 million after deducting the initial purchasers' discounts and our offering expenses. The proceeds were used to repay borrowings under our Credit Facility and for related transaction fees and expenses.
Optional Redemption. We have the option, at any time or from time to time prior to June 15, 2024 (which is three months prior to the maturity date of the 2024 notes) to redeem some or all of the Notes at a specified "make whole" premium as described in the Indenture. We also have the option at any time or from time to time on or after June 15, 2024, to redeem some or all of the Notes at a redemption price equal to 100% of the principal amount of the Notes to be redeemed.
Change of Control. If we experience a change of control (as defined in the indenture governing the Notes) accompanied by a specified rating decline, we must offer to repurchase the Notes at 101% of their principal amount, plus accrued and unpaid interest.
Covenants. The terms of the Indenture restrict our ability and the ability of our subsidiaries to incur additional indebtedness secured by liens and to effect a consolidation, merger or sale of substantially all our assets. The Indenture also requires us to file with the trustee and the SEC certain documents and reports within certain time limits set forth in the Indenture. However, these limitations and requirements are subject to a number of important qualifications and exceptions. The Indenture does not require the maintenance of any financial ratios or specified levels of net worth or liquidity.
Events of Default. Each of the following is an "Event of Default" under the Indenture with respect to the Notes:
(1) a default in the payment of interest on the Notes when due that continues for 30 days;
(2) a default in the payment of the principal of or any premium, if any, on the Notes when due at their stated maturity, upon redemption, or otherwise;
(3) failure by us to duly observe or perform any other of the covenants or agreements (other than those described in clause (1) or (2) above) in the indenture, which failure continues for a period of 60 days, or, in the case of the reporting covenant under the indenture, which failure continues for a period of 90 days, after the date on which written notice of such failure has been given to us by the trustee; provided, however, that if such failure is not capable of cure within such 60-day or 90-day period, as the case may be, such 60-day or 90-day period, as the case may be, will be automatically extended by an additional 60 days so long as (i) such failure is subject to cure and (ii) we are using commercially reasonable efforts to cure such failure; and
(4) certain events of bankruptcy, insolvency or reorganization described in the Indenture.
Credit Facility

At September 30, 2014 we had a $1.5 billion five-year senior unsecured revolving credit facility agreement (the “Credit Facility Agreement”) that was set to expire in 2016. Under the terms of the Credit Facility Agreement and subject to certain

requirements, we could request an increase in the commitments of up to an additional $300 million by either commitments from new lenders or increased commitments from existing lenders. As of September 30, 2014, the variable interest rate was 4.13 percent on the $45 million outstanding under the Credit Facility Agreement.
Subsequent to September 30, 2014, we amended and restated the Credit Facility Agreement, hereafter referred to as the "New Credit Facility Agreement". The terms of the New Credit Facility Agreement are materially the same as our Credit Facility Agreement, except that the New Credit Facility Agreement matures on October 28, 2019, the letters of credit sublimit is $750 million and we changed the Applicable Rates and revised our financial covenants as set forth below. As of November 4, 2014, we had $210 million outstanding under the New Credit Facility Agreement and approximately $1.3 billion of available capacity.
Under the New Credit Facility Agreement, when our Index Debt is not rated BBB- or better by S&P or Baa3 or better by Moody's and not less than BB+ or Ba1 by the other such agency, we will be required to maintain a ratio of Consolidated Net Indebtedness (as defined in the New Credit Facility Agreement) to Consolidated EBITDAX (as defined in the New Credit Facility Agreement) of not greater than 3.75 to 1.00. Consolidated Net Indebtedness includes a reduction attributable to unrestricted cash and cash equivalents not to exceed $50 million. Consolidated EBITDAX will be calculated for the four fiscal quarters ending on the last day of any fiscal quarter for which financial statements have been or were required to be delivered. Additionally, the ratio of Consolidated Indebtedness (as defined in the New Credit Facility Agreement) to Consolidated Total Capitalization (defined as Consolidated Indebtedness plus Consolidated Net Worth) will not be permitted to be greater than 60 percent and will be applicable for the life of the agreement. During a Downgrade Period (as defined in the New Credit Facility Agreement), we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the New Credit Facility Agreement, to Consolidated Indebtedness ratio of at least 1.25 to 1.00 for fiscal periods ending on or prior to December 31, 2015, and 1.50 to 1.00 thereafter. This covenant will not apply after the occurrence of the Investment Grade Date, which is the first date after closing on which our Index Debt ratings are BBB- or better by S&P or Baa3 or better by Moody's (without negative outlook or watch by either agency), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody's.

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 New Credit Facility Agreement. At September 30, 2014, a total of $324 million in letters of credit have been issued.

Note 7. Provision (Benefit) for Income Taxes

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
	(Millions)			
Current:				
Federal	$(5)	$(31)	$12	$(28)
State	(3)	—	1	—
Foreign	4	3	8	11
	(4)	(28)	21	(17)
Deferred:				
Federal	29	(27)	(59)	(84)
State	3	12	6	8
Foreign	—	14	1	14
	32	(1)	(52)	(62)
Total provision (benefit)	$28	$(29)	$(31)	$(79)

The effective tax rate for all periods presented above differs from the federal statutory rate primarily due to the effects of state income taxes and taxes on foreign operations.

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. As a result we recorded an additional $9 million of deferred tax expense in the first quarter of 2014 to accrue for the impact of this new legislation.

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Notes to Consolidated Financial Statements — (Continued)

As of September 30, 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.

In September 2013, the Argentine government enacted tax reform legislation related to dividends and capital gains which will apply to the Argentine operations of our consolidated investment in Apco, a Cayman Islands corporation. As a result, Apco recorded approximately $14 million of foreign deferred tax expense during third quarter 2013. This accrual was partially offset by approximately $4 million of U.S. deferred tax benefit recorded by WPX.

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 adjustments unrelated to our business.

Note 8. Contingent Liabilities

Royalty litigation

In September 2006, royalty interest owners in Garfield County, Colorado, filed a class action suit in District Court, Garfield County, Colorado, alleging we improperly calculated oil and gas royalty payments, failed to account for proceeds received from the sale of natural gas and extracted products, improperly charged certain expenses and failed to refund amounts withheld in excess of ad valorem tax obligations. Plaintiffs sought to certify a class of royalty interest owners, recover underpayment of royalties and obtain corrected payments related to calculation errors. We entered into a final partial settlement agreement. The partial settlement agreement defined the class for certification, resolved claims relating to past calculation of royalty and overriding royalty payments, established certain rules to govern future royalty and overriding royalty payments, resolved claims related to past withholding for ad valorem tax payments, established a procedure for refunds of any such excess withholding in the future, and reserved two claims for court resolution. We have prevailed at the trial court and all levels of appeal on the first reserved claim regarding whether we are allowed to deduct mainline pipeline transportation costs pursuant to certain lease agreements. The remaining claim 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 have completed the process under that standard of conducting an accounting, and the parties have jointly submitted the information to the court for approval. 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, fraudulent concealment, conversion, misstatement of the value of gas and affiliated sales, breach of duty to market hydrocarbons in Colorado, violation of the New Mexico Oil and Gas Proceeds Payment Act, and bad faith breach of contract. Plaintiffs 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

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

to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (“ONRR”) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The guidelines for New Mexico properties were revised slightly in September 2013 as a result of additional work performed by the ONRR. The revisions did not change the basic function of the original guidance. The ONRR’s guidance provides its view as to how much of a producer’s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in other states though such guidelines are expected in the future. However, the timing of any such guidance is uncertain and, independent of the issuance of additional guidance, ONRR asked producers to attempt to evaluate the deductibility of these fees directly with the midstream companies that transport and process gas. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR’s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR’s predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From October 2007 through September 2014, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $113 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.

Matter 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 litigation described below relating to the reporting of certain natural gas-related information to trade publications.

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

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs’ state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs’ class certification motion as moot. The plaintiffs appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion 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. The U.S. Supreme Court granted Defendants' writ of certiorari. 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.

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

At September 30, 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.

Summary

As of September 30, 2014 and December 31, 2013, the Company had accrued approximately $20 million and $16 million, respectively, for loss contingencies associated with royalty litigation and other contingencies. In certain circumstances, we may be eligible for insurance recoveries, or reimbursement from others. Any such recoveries or reimbursements will be recognized only when realizable.

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

Note 9. Fair Value Measurements

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

	September 30, 2014				December 31, 2013			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(Millions)				(Millions)			
Energy derivative assets	$18	$110	$1	$129	$30	$26	$1	$57
Energy derivative liabilities	$61	$26	$—	$87	$83	$38	$1	$122
Total debt (a)	$—	$2,081	$—	$2,081	$—	$1,945	$—	$1,945

(a) The carrying value of total debt, excluding capital leases, was $2,051 million and $1,918 million as of September 30, 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, option and swaption contracts included in Level 2 are valued using an income approach including present value techniques and option pricing models. Option contracts, which hedge future sales of our production, are structured as costless collars or as swaptions and are financially settled. All of our financial options are valued using an industry standard Black-Scholes option pricing model. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions grant the counterparty the option to enter into future swaps with us. Significant inputs into our Level 2 valuations include commodity prices, implied volatility and interest rates, as well as considering executed transactions or broker quotes corroborated by other market data. These broker quotes are based on observable market prices at which transactions could currently be executed. In certain instances where these inputs are not observable for all periods, relationships of observable market data and historical observations are used as a means to estimate fair value. Also categorized as Level 2 is the fair value of our debt, which is determined on market rates and the prices of similar securities with similar terms and credit ratings. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Our energy derivatives portfolio is largely comprised of exchange-traded products or like products and the tenure of our derivatives portfolio 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 a net asset of $1 million at September 30, 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 September 30, 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 10. Derivatives and Concentration of Credit Risk

Energy Commodity Derivatives

Risk Management Activities

We are exposed to market risk from changes in energy commodity prices within our operations. We utilize derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas, oil and natural gas liquids attributable to commodity price risk. Through December 2011, we elected to designate the majority of our applicable derivative instruments as cash flow hedges. Beginning in 2012, we entered into commodity derivative contracts that continued to serve as economic hedges but were not designated as cash flow hedges for accounting purposes as we elected not to utilize this method of accounting on new derivatives instruments. Remaining commodity derivatives recorded at December 31, 2011 that were designated as cash flow hedges were fully realized by the end of the first quarter of 2013.

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

We also enter into forward contracts to buy and sell natural gas to maximize the economic value of transportation agreements and storage capacity agreements. To reduce exposure to a decrease in margins from fluctuations in natural gas market prices, we may enter into futures contracts, swap agreements and financial option contracts to mitigate the price risk 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, which are included in our commodity derivatives portfolio as of September 30, 2014.

Derivatives related to production

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)	Weighted Average Price (c)
Natural Gas					
Natural Gas	Oct-Dec 2014	Fixed Price Swaps	Henry Hub	(315)	$4.19
Natural Gas	Oct-Dec 2014	Swaptions	Henry Hub	(50)	$4.24
Natural Gas	Oct-Dec 2014	Costless Collars	Henry Hub	(190)	$ 4.04 - 4.66
Natural Gas	Oct-Dec 2014	Basis Swaps	Dominion	(39)	$(0.73)
Natural Gas	Oct-Dec 2014	Basis Swaps	NGPL	(30)	$(0.19)
Natural Gas	Oct-Dec 2014	Basis Swaps	Rockies	(143)	$(0.15)
Natural Gas	Oct-Dec 2014	Basis Swaps	San Juan	(255)	$(0.15)
Natural Gas	Oct-Dec 2014	Basis Swaps	SoCal	(73)	$0.13
Natural Gas	2015	Fixed Price Swaps	Henry Hub	(272)	$4.31
Natural Gas	2015	Swaptions	Henry Hub	(50)	$4.38
Natural Gas	2015	Costless Collars	Henry Hub	(50)	$ 4.00 - 4.50
Natural Gas	2015	Basis Swaps	NGPL	(13)	$(0.16)
Natural Gas	2015	Basis Swaps	Rockies	(150)	$(0.11)
Natural Gas	2015	Basis Swaps	San Juan	(85)	$(0.10)
Natural Gas	2015	Basis Swaps	SoCal	(20)	$0.18
Natural Gas	2016	Swaptions	Henry Hub	(90)	$4.23
Crude Oil					
Crude Oil	Oct-Dec 2014	Fixed Price Swaps	WTI	(14,975)	$96.01
Crude Oil	2015	Fixed Price Swaps	WTI	(20,236)	$94.88
Crude Oil	2015	Swaptions	WTI	(8,382)	$94.90
Crude Oil	2016	Swaptions	WTI	(5,250)	$97.55
NGL					
NGL Ethane	Oct-Dec 2014	Fixed Price Swaps	Mont Belvieu	(3,261)	$0.29
NGL Propane	Oct-Dec 2014	Fixed Price Swaps	Mont Belvieu	(489)	$1.17
NGL Iso Butane	Oct-Dec 2014	Fixed Price Swaps	Mont Belvieu	(652)	$1.37
NGL Normal Butane	Oct-Dec 2014	Fixed Price Swaps	Mont Belvieu	(652)	$1.34
NGL Natural Gasoline	Oct-Dec 2014	Fixed Price Swaps	Mont Belvieu	(1,630)	$2.06

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(a) 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.

(b) Natural gas volumes are reported in BBtu/day, crude oil volumes are reported in Bbl/day, and natural gas liquids are reported in Bbl/day.

(c) The weighted average price for natural gas is reported in $/MMBtu, the crude oil price is reported in $/Bbl and natural gas liquids are reported in $/Gallon. All natural gas basis swaps are based on a differential to Henry Hub.

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

The following table sets forth the derivative notional volumes of the net long (short) positions of derivatives primarily related to storage and transportation contracts, which are included in our commodity derivatives portfolio as of September 30, 2014.

Derivatives primarily related to storage and transportation

Commodity	Period	Contract Type (a)	Location (b)	Notional Volume (c)	Weighted Average Price (d)
Natural Gas	Oct-Dec 2014	Fixed Price Swaps	Multiple	8	—
Natural Gas	Oct-Dec 2014	Basis Swaps	Multiple	(31)	—
Natural Gas	Oct-Dec 2014	Index	Multiple	(145)	—
Natural Gas	2015	Fixed Price Swaps	Multiple	(11)	—
Natural Gas	2015	Basis Swaps	Multiple	(12)	—
Natural Gas	2015	Index	Multiple	(118)	—
Natural Gas	2016	Index	Multiple	(70)	—
Natural Gas	2017+	Index	Multiple	(478)	—

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(a) 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.

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

(c) 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.

(d) 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.

Fair values and gains (losses)

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

	September 30, 2014		December 31, 2013	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production not designated as hedging instruments	$110	$26	$26	$39
Derivatives related to physical marketing agreements not designated as hedging instruments	19	61	31	83
Total derivatives not designated as hedging instruments	$129	$87	$57	$122

During the first nine months 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.

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
	(Millions)			
Gain (loss) from derivatives related to production not designated as hedging instruments (a)	$150	$(18)	$40	$(29)
Gain (loss) from derivatives related to physical marketing agreements not designated as hedging instruments (b)	(2)	3	(104)	(2)
Net gain (loss) on derivatives not designated as hedges	$148	$(15)	$(64)	$(31)

(a) Includes receipts totaling $10 million and $1 million for settlements of derivatives during the three months ended September 30, 2014 and 2013, respectively; and payments totaling $57 million and $14 million for the nine months ended September 30, 2014 and 2013, respectively.

(b) Includes receipts totaling $5 million for settlements of derivatives during the three months ended September 30, 2014 and payments totaling $2 million during the three months ended September 30, 2013; and payments totaling $114 million for the nine months ended September 30, 2014 and receipts of $1 million for the nine months ended September 30, 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.

Offsetting of derivative assets and liabilities

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

	Gross Amount Presented on Balance Sheet	Netting Adjustments (a)	Cash Collateral Posted (Received)	Net Amount
September 30, 2014	(Millions)			
Derivative assets with right of offset or master netting agreements	$129	$(43)	$—	$86
Derivative liabilities with right of offset or master netting agreements	$(87)	$43	$43	$(1)
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)

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

Credit-risk-related features

Certain of our derivative contracts contain credit-risk-related provisions that would require us, under certain events, to post additional collateral in support of our net derivative liability positions. These credit-risk-related provisions require us to post collateral in the form of cash or letters of credit when our net liability positions exceed an

established credit threshold. The credit thresholds are typically based on our senior unsecured debt ratings from Standard and Poor’s and/or Moody’s Investment Services. Under these contracts, a credit ratings decline would lower our credit thresholds, thus requiring us to post additional collateral. We also have contracts that contain adequate assurance provisions giving the counterparty the right to request collateral in an amount that corresponds to the outstanding net liability.
As of September 30, 2014, we had collateral totaling $51 million posted to derivative counterparties, which included $8 million of initial margin to clearinghouses or exchanges to enter into positions and $43 million of maintenance margin for

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

changes in the fair value of those positions, to support the aggregate fair value of our net $44 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 $1 million at September 30, 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.

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 September 30, 2014, is summarized as follows:

Counterparty Type	Gross Investment Grade (a)	Gross Total	Net Investment Grade (a)	Net Total
	(Millions)			
Financial institutions	$128	$128	$85	$85
Utilities	—	1	—	1
	$128	129	$85	86
Credit reserves		—		—
Credit exposure from derivatives		$129		$86

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(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 nine largest net counterparty positions represent approximately 94 percent of our gross 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

The customer margin deposits payable as of September 30, 2014 related to our commodity agreements. Collateral support for our commodity agreements could also include letters of credit and guarantees of payment by credit worthy parties.

Note 11. Segment Disclosures

Our reporting segments are domestic and international (see Note 1).
Our segment presentation is reflective of the parent-level focus by our chief operating decision-maker, considering the resource allocation and governance provisions. Domestic and international maintain separate capital and cash management structures. These factors, coupled with differences in the business environment associated with operating in different countries, serve to differentiate the management of this entity as a whole.

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

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.

	Domestic	International	Total
		(Millions)	
Three months ended September 30, 2014			
Total revenues	$747	$47	$794
Costs and expenses:			
Lease and facility operating	$63	$10	$73
Gathering, processing and transportation	82	—	82
Taxes other than income	32	8	40
Gas management, including charges for unutilized pipeline capacity	164	—	164
Exploration (Note 4)	28	1	29
Depreciation, depletion and amortization	201	12	213
Loss on sale of working interests in the Piceance Basin	1	—	1
General and administrative	71	4	75
Other—net	3	—	3
Total costs and expenses	$645	$35	$680
Operating income (loss)	$102	$12	$114
Interest expense	(31)	—	(31)
Interest capitalized	1	—	1
Investment income and other	(1)	6	5
Income (loss) from continuing operations before income taxes	$71	$18	$89
Three months ended September 30, 2013			
Total revenues	$581	$35	$616
Costs and expenses:			
Lease and facility operating	$62	$8	$70
Gathering, processing and transportation	88	—	88
Taxes other than income	27	6	33
Gas management, including charges for unutilized pipeline capacity	201	—	201
Exploration (Note 4)	21	—	21
Depreciation, depletion and amortization	222	8	230
Impairment of costs of acquired unproved reserves (Note 4)	19	—	19
General and administrative	64	3	67
Other—net	(2)	3	1
Total costs and expenses	$702	$28	$730
Operating income (loss)	$(121)	$7	$(114)
Interest expense	(28)	—	(28)
Interest capitalized	1	—	1
Investment income and other	—	4	4
Income (loss) from continuing operations before income taxes	$(148)	$11	$(137)

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

	Domestic	International (Millions)	Total
Nine months ended September 30, 2014			
Total revenues	$2,368	$117	$2,485
Costs and expenses:			
Lease and facility operating	$182	$26	$208
Gathering, processing and transportation	249	1	250
Taxes other than income	100	21	121
Gas management, including charges for unutilized pipeline capacity	788	—	788
Exploration (Note 4)	97	4	101
Depreciation, depletion and amortization	596	31	627
Loss on sale of working interests in the Piceance Basin	196	—	196
General and administrative	208	11	219
Other—net	6	3	9
Total costs and expenses	$2,422	$97	$2,519
Operating income (loss)	$(54)	$20	$(34)
Interest expense	(88)	—	(88)
Interest capitalized	1	—	1
Investment income and other	(1)	13	12
Income (loss) from continuing operations before income taxes	$(142)	$33	$(109)
Nine months ended September 30, 2013			
Total revenues	$1,855	$113	$1,968
Costs and expenses:			
Lease and facility operating	$170	$26	$196
Gathering, processing and transportation	262	2	264
Taxes other than income	77	18	95
Gas management, including charges for unutilized pipeline capacity	666	—	666
Exploration (Note 4)	55	4	59
Depreciation, depletion and amortization	637	25	662
Impairment of costs of acquired unproved reserves (Note 4)	19	—	19
General and administrative	198	11	209
Other—net	10	—	10
Total costs and expenses	$2,094	$86	$2,180
Operating income (loss)	$(239)	$27	$(212)
Interest expense	(82)	—	(82)
Interest capitalized	1	—	1
Investment income and other	1	16	17
Income (loss) from continuing operations before income taxes	$(319)	$43	$(276)
Total assets			
Total assets as of September 30, 2014	$7,838	$406	$8,244
Total assets as of December 31, 2013	$8,046	$383	$8,429

Note 12. Subsequent Events

On October 3, 2014, we announced an agreement to sell our international interests for approximately $294 million subject to the successful consummation of the definitive merger agreement entered into between Pluspetrol Resources Corporation and Apco Oil and Gas International ("APCO"). Our international interests include a 69 percent controlling equity interest in APCO, additional non-material assets in wholly-owned Northwest Argentina and a 5 percent interest in Apco Argentina. Our international interests did not qualify as assets held for sale as of September 30, 2014. Therefore, the results of operations and financial position of our international segment will be reported in discontinued operations in future filings.

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.

During the third quarter of 2014, we signed an agreement for the sale of our remaining mature, coalbed methane holdings in the Powder River Basin in Wyoming. As a result, we have reported the results of operations and financial position of the Powder River Basin as discontinued operations. Unless indicated otherwise, the following discussion relates to continuing operations.

Overview

The following table presents our production volumes and financial highlights for the three and nine months ended September 30, 2014 and 2013:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Production Sales Data: (a)				
Domestic natural gas (MMcf)	68,614	75,497	212,117	223,262
Domestic oil (MBbls)	2,373	1,571	6,269	4,183
Domestic NGLs (MBbls)	1,574	1,810	4,786	5,607
Domestic combined equivalent volumes (MMcfe) (b)	92,295	95,782	278,450	281,999
Domestic per day combined equivalent volumes (MMcfe/d)	1,003	1,041	1,020	1,033
Domestic combined equivalent volumes (MBoe)	15,383	15,964	46,408	47,000
International combined equivalent volumes (MMcfe) (b) (c)	5,728	4,862	15,422	14,839
International per day combined equivalent volumes (MMcfe/d) (c)	62	53	56	54
International combined equivalent volumes (MBoe) (c)	955	810	2,570	2,473
Financial Data (millions):				
Total domestic revenues	$747	$581	$2,368	$1,855
Total international revenues	$47	$35	$117	$113
Consolidated operating income (loss)	$114	$(114)	$(34)	$(212)
Consolidated capital expenditures	$597	$295	$1,325	$843

(a) Excludes production from our Powder River Basin operations which is classified as discontinued operations.

(b) 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.

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

Our third-quarter 2014 operating results were $228 million favorable compared to third-quarter 2013. The primary favorable impacts include $49 million higher product sales, $168 million favorable change in gain (loss) on derivatives related to production, primarily natural gas and crude, $17 million decrease in depreciation, depletion and amortization and the absence of a $19 million impairment of costs of acquired unproved reserves in 2013.

Our year to date 2014 operating results were $178 million favorable compared to year to date 2013. The primary favorable impacts to our year to date 2014 operating results include $99 million higher natural gas sales, $165 million higher oil and condensate sales, a $173 million increase in gas management margin partially offset by the $196 million loss on the sale of a portion of our working interests in certain Piceance Basin wells and a $102 million increase in the loss on derivatives related to gas management.

Outlook

On October 8, 2014, we announced a strategy to simplify our geographic focus and expand returns, margins and cash flow over the next five years. Key to this strategy are the core resource plays in North Dakota, New Mexico and Colorado. As a result, we will look to exit or scale back activities in our other areas. We have made significant progress toward this goal as evidenced by the announced agreements for sales of our coalbed methane assets in Wyoming and our international interests in APCO.

We continue to focus on growing our oil production and developing oil reserves located in the Williston Basin in North Dakota and the Gallup Sandstone in the San Juan Basin. We have seen positive results in 2014 from completing wells in a tighter infill well density and increasing the proppant in well completions in the Williston Basin. In the Gallup Sandstone, we had 33 spuds performed as of September 30, 2014 versus a plan of 24. Additionally, we have added acreage through acquisitions that brings the total we own or control to 84,000 net acres and we have added a third rig during the third quarter. We expect to spud a total of 48 wells by year end. 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 48 oil wells (gross) in the Gallup Sandstone, an increase of 270 percent versus 2013.

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 plan to deploy an average of nine drilling rigs in the Piceance Basin for 2014 which includes a drilling rig focused on the Niobrara Shale discussed below. Our initial goal for 2014 was to increase production over current levels, however, our production in the Piceance Basin will be lower as a result of the sale of a portion of our working interests discussed below. Our drilling activity has primarily been focused in the Piceance Valley, however, we will start to shift more capital to opportunities in the Ryan Gulch field of the Piceance Basin where we have more than 4,000 drillable locations at 10-acre spacing. We will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities, and negotiating lower costs for vendor goods and services. Additionally, we continue to review 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 a portion 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 terms of the sale also provided us with a 10 percent ownership in a newly created class of incentive distribution rights ("IDR") of Legacy. The working interests represent approximately 300 billion cubic feet of proved reserves, or approximately 6 percent of WPX's year-end 2013 proved reserves. Production related to these working interests for January through May approximated 70 MMcfe/day of our production. The sale closed at the beginning of June and we received proceeds of $337 million, which were subject to post closing adjustments including settlement of production for April and May. We estimate the amount to be remitted to Legacy in the fourth quarter will be $12 million. Based on an estimated total value received at closing of $329 million, which represents estimated final cash proceeds and an estimated fair value of the IDRs, we recorded a $195 million loss on the sale in the second quarter of 2014. In the third quarter of 2014, we recorded an additional loss on sale of $1 million related to this transaction.

Approximately 5 percent of our estimated annual capital spending in 2014 will be for exploratory drilling activities, primarily for further delineation of our Niobrara Shale discovery in the Piceance Basin. Our initial Niobrara Shale discovery well in the Piceance Basin produced 2.2 billion cubic feet of natural gas in the first year of operation. Since the initial discovery well, we have drilled seven additional wells in 2013 and 2014 reflecting three vertical test wells and four horizontal wells, one of which was plugged due to a casing issue in the lateral section before completion began. WPX is planning to re-drill this well later this year. Initial drilling and production results thus far have validated the existence of a highly pressured continuous gas accumulation in the Niobrara formations capable of producing pipeline-quality gas. Vertical test wells have also indicated potential additional stacked pay in the Mancos formation. Future drilling will focus on driving down costs while optimizing completion techniques to move this project to commercial development. We plan to double our Niobrara delineation drilling in 2014 with up to 6 wells expected and we recently completed a 3-D seismic shoot in 2014 in the Grand Valley field which brings our seismic coverage of our Piceance Valley acreage to 70 percent. We are also in the process of drilling test wells in other new areas. As of September 30, 2014, our total domestic capitalized well costs associated with our exploratory areas, including the Niobrara Shale in the Piceance Basin, totaled approximately $70 million. We will also continue to evaluate the purchase of leasehold in current exploratory plays and other areas.

We anticipate our total capital spending in 2014 will be approximately $1.8 billion, including acquisition capital. Through September 30, 2014, our capital expenditures totaled $1.3 billion. 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.

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. As noted in our Form 10-K, 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. Current forward prices do not indicate impairments. 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	Oct - Dec 2014		2015	
	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)	Volume (BBtu/d)	Weighted Average Price ($/MMBtu)
Fixed-price—Henry Hub	315	$4.19	272	$4.31
Swaptions—Henrry Hub	50	$4.24	50	$4.38
Collars—Henry Hub	190	$ 4.04 - 4.66	50	$ 4.00 - 4.50
Basis swaps—Dominion	39	$(0.73)	—	$—
Basis swaps—NGPL	30	$(0.19)	13	$(0.16)
Basis swaps—San Juan	255	$(0.15)	85	$(0.10)
Basis swaps—Rockies	143	$(0.15)	150	$(0.11)
Basis swaps—SoCal	73	$0.13	20	$0.18

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Crude Oil	Oct - Dec 2014		2015	
	Volume (Bbls/d)	Weighted Average Price ($/Bbl)	Volume (Bbls/d)	Weighted Average Price ($/Bbl)
Fixed-price—WTI	14,975	$96.01	20,236	$94.88
Swaptions—WTI	—	$—	8,382	$94.90

Natural Gas Liquids	Oct - Dec 2014	
	Volume (Bbls/d)	Weighted Average Price ($/Gal)
Fixed-price—Mont Belvieu Ethane	3,261	$0.29
Fixed-price—Mont Belvieu Propane	489	$1.17
Fixed-price—Mont Belvieu Iso Butane	652	$1.37
Fixed-price—Mont Belvieu Normal Butane	652	$1.34
Fixed-price—Mont Belvieu Natural Gasoline	1,630	$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. In conjunction with the closing of the Powder River sale and current terms therein, we may record certain pipeline capacity obligations associated with exiting the Powder River Basin. Our total commitments related to these pipeline agreements for 2015 and beyond total $140 million. We also hold an obligation, which expires on November 11, 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. With the expiration of this obligation and based on current market expectations, we expect our natural gas revenues to improve by more than $100 million on an annualized basis.

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 primarily located in Colorado, New Mexico and North Dakota in the United States. Our development and production techniques specialize in production from tight-sands and shale formations as well as coalbed methane reserves in the Piceance, Williston, San Juan Basins. We also have operations and interests in the Appalachian and Green River Basins located in Pennsylvania and Wyoming. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation, storage and related derivatives coupled with the sale of our commodity volumes.

During the third quarter of 2014, we signed an agreement for the sale of our remaining mature, coalbed methane holdings in the Powder River Basin in Wyoming (see Note 2 of Notes to Consolidated Financial Statements). As a result, we have reported the results of operations and financial position of the Powder River Basin as discontinued operations. Unless indicated otherwise, the following discussion relates to continuing operations.

International primarily consists of our ownership in Apco, an oil and gas exploration and production company with activities in Argentina and Colombia. See Note 12 of Notes to Consolidated Financial Statements for a discussion of a recently announced agreement to sell our international interests.

Three Month-Over-Three Month Results of Operations

Revenue Analysis

	Three months ended September 30,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2014	2013		
	(Millions)			
Domestic revenues:				
Natural gas sales	$201	$206	$(5)	(2)%
Oil and condensate sales	199	154	45	29%
Natural gas liquid sales	53	57	(4)	(7)%
Total product revenues	453	417	36	9%
Gas management	145	176	(31)	(18)%
Net gain (loss) on derivatives not designated as hedges	148	(15)	163	NM
Other	1	3	(2)	(67)%
Total domestic revenues	$747	$581	$166	29%
Total international revenues	$47	$35	$12	34%
Total revenues	$794	$616	$178	29%

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

Domestic Revenues

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

- $5 million decrease in natural gas sales reflects a $19 million decrease related to lower production sales volumes partially offset by a $12 million increase related to higher sales prices . The decrease in our production sales volumes is primarily due to the impact of the sale of a portion of our working interests to Legacy during second-quarter 2014 (see Note 4 of Notes to Consolidated Financial Statements). Natural gas production from the Piceance Basin represents approximately 73 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for the three months ended September 30, 2014 and 2013:

	Three months ended September 30,	
	2014	2013
Natural gas sales (per Mcf)	$2.92	$2.75
Impact of net cash received (paid) related to settlement of derivatives (per Mcf) (a)	0.15	0.05
Natural gas net price including derivative settlements (per Mcf)	$3.07	$2.80
Natural gas production sales volumes (MMcf)	68,614	75,497
Per day natural gas production sales volumes (MMcf/d)	746	821

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

- $45 million increase in oil and condensate sales reflects increased production sales volumes for the three months ended September 30, 2014 as compared to 2013 partially offset by lower sales prices. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin where the volumes were 20.1 MBbls per day for the three months ended September 30, 2014 compared to 14.0 MBbls per day for the same period in 2013. The San Juan Basin also had production of 3.9 MBbls per day for 2014 related to the Gallup Sandstone development. The following table reflects oil and condensate production prices and volumes for the three months ended September 30, 2014 and 2013:

	Three months ended September 30, 2014	2013
Oil sales (per barrel)	$84.11	$97.94
Impact of net cash received (paid) related to settlement of derivatives (per barrel) (a)	(0.70)	(2.64)
Oil net price including derivative settlements (per barrel)	$83.41	$95.30
Oil and condensate production sales volumes (MBbls)	2,373	1,571
Per day oil and condensate production sales volumes (MBbls/d)	25.8	17.1

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

- $4 million decrease in natural gas liquids sales reflects decreased production sales volumes despite a higher price per barrel for the three months ended September 30, 2014 compared to the same period in 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 September 30, 2014 and 2013:

	Three months ended September 30, 2014	2013
NGL sales (per barrel)	$33.64	$31.20
Impact of net cash received (paid) related to settlement of derivatives (per barrel) (a)	0.66	0.08
NGL net price including derivative settlements (per barrel)	$34.30	$31.28
NGL production sales volumes (MBbls)	1,574	1,810
Per day NGL production sales volumes (MBbls/d)	17.1	19.7

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(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 September 30, 2014 and 2013:

	Three months ended September 30, 2014		2013	
	% of barrel	$/gallon	% of barrel	$/gallon
Ethane	29%	$0.28	36%	$0.26
Propane	33%	$1.05	29%	$1.05
Iso-Butane	9%	$1.28	8%	$1.36
Normal Butane	7%	$1.25	8%	$1.35
Natural Gasoline	22%	$2.08	19%	$2.19

- $31 million decrease in gas management revenues primarily due to lower average prices on physical natural gas sales as well as lower commodity sales volumes. We experienced a similar decrease of $37 million in related gas management costs and expenses, discussed below.
- $163 million favorable change in net gain (loss) on derivatives not designated as hedges primarily reflects a $159 million favorable change in unrealized gains (losses) on derivatives related to production, primarily natural gas and crude.

International Revenues

International revenues increased primarily due to increased oil sales from our Colombian operations for the three months ended September 30, 2014 compared to the same period in 2013.

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

	Three months ended September 30,		Favorable (Unfavorable)	Favorable (Unfavorable) %
	2014	2013	$ Change	Change
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$63	$62	$(1)	(2)%
Gathering, processing and transportation	82	88	6	7%
Taxes other than income	32	27	(5)	(19)%
Gas management, including charges for unutilized pipeline capacity	164	201	37	18%
Exploration	28	21	(7)	(33)%
Depreciation, depletion and amortization	201	222	21	9%
Impairment of costs of acquired unproved reserves	—	19	19	100%
Loss on sale of working interests in the Piceance Basin	1	—	(1)	NM
General and administrative	71	64	(7)	(11)%
Other—net	3	(2)	(5)	NM
Total domestic costs and expenses	$645	$702	$57	8%
International costs and expenses:				
Lease and facility operating	$10	$8	$(2)	(25)%
Taxes other than income	8	6	(2)	(33)%
Exploration	1	—	(1)	NM
Depreciation, depletion and amortization	12	8	(4)	(50)%
General and administrative	4	3	(1)	(33)%
Other—net	—	3	3	100%
Total international costs and expenses	$35	$28	$(7)	(25)%
Total costs and expenses	$680	$730	$50	7%
Domestic operating income (loss)	$102	$(121)	$223	NM
International operating income	$12	$7	$5	71%

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:

- $1 million increase in lease and facility operating expenses primarily relates to the impact of increased production in the Williston and San Juan Basins in relation to our overall portfolio partially offset by the impact of the sale of a portion of our working interests in certain Piceance Basin wells. Lease and facility operating expense averaged $0.68 per Mcfe for the three months ended September 30, 2014 compared to $0.64 per Mcfe for the same period in 2013.

- $6 million decrease in gathering, processing and transportation expenses primarily related to lower volumes. Gathering, processing and transportation expenses averaged $0.89 per Mcfe for the three months ended September 30, 2014 and $0.90 per Mcfe for the same period in 2013.
- $5 million increase in taxes other than income from 2014 compared to 2013 relates to increased crude oil production volumes in the Williston Basin. Taxes other than income averaged $0.35 per Mcfe for the three months ended September 30, 2014 compared to $0.28 per Mcfe for the same period in 2013.
- $37 million decrease in gas management expenses primarily due to lower average prices on physical natural gas cost of sales as well as lower commodity purchase volumes. Also included in gas management expenses are $16 million and $17 million for the three months ended September 30, 2014 and 2013, respectively, for unutilized pipeline capacity.
- $7 million increase in exploration expenses primarily relates to impairments of exploratory area leasehold and well costs in exploratory plays for which management no longer intends to continue exploratory activities (see Note 4 of Notes to Consolidated Financial Statements).
- $21 million decrease in depreciation, depletion and amortization primarily due to lower natural gas production volumes as previously discussed, partially offset by the impact of increased oil production which is at a higher rate per Mcfe. During the three months ended September 30, 2014, our depreciation, depletion and amortization averaged $2.18 per Mcfe compared to an average $2.31 per Mcfe for the same period in 2013.
- $19 million property impairment of cost of acquired unproved reserves in the Kokopelli area of the Piceance Basin in 2013.
- $7 million increase in general and administrative expenses due to approximately $8 million related to costs associated with an early exit program offered during 2014. General and administrative expenses averaged $0.77 per Mcfe for the three months ended September 30, 2014 compared to $0.66 for the same period in 2013. Excluding the impact of the early exit program costs, the average expense for the three months ended September 30, 2014 would have been $0.68 per Mcfe.

International costs

International costs and expenses increased primarily due to an increase in depreciation, depletion and amortization and lease and facility operating expense related to increased oil volumes.

Consolidated results below operating income (loss)

	Three months ended September 30, 2014	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Consolidated operating income (loss)	$114	$(114)	$228	NM
Interest expense	(31)	(28)	(3)	(11)%
Interest capitalized	1	1	—	—%
Investment income and other	5	4	1	25%
Income (loss) from continuing operations before income taxes	89	(137)	226	NM
Provision (benefit) for income taxes	28	(29)	(57)	NM
Income (loss) from continuing operations	61	(108)	169	NM
Income (loss) from discontinued operations	5	(8)	13	NM
Net income (loss)	66	(116)	182	NM
Less: Net income (loss) attributable to noncontrolling interests	4	(2)	6	NM
Net income (loss) attributable to WPX Energy, Inc.	$62	$(114)	$176	NM

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

Provision for income taxes changed unfavorably due to pre-tax income in 2014 compared to pre-tax loss in 2013. See Note 7 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods. Income taxes in 2013 include a $9 million deferred tax provision related to the increase in a valuation allowance on certain state deferred tax assets. Income taxes in 2013 also included a $10 million provision related to the impact of the new capital tax law in Argentina.

The change in income (loss) from discontinued operations was primarily due to lower depreciation, depletion and amortization in 2014 and an accrual for litigation of $7 million in 2013.

Nine Month-Over-Nine Month Results of Operations

Revenue Analysis

	Nine months ended September 30, 2014 (Millions)	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
Domestic revenues:				
Natural gas sales	$780	$685	$95	14 %
Oil and condensate sales	542	386	156	40 %
Natural gas liquid sales	168	168	—	— %
Total product revenues	1,490	1,239	251	20 %
Gas management	937	642	295	46 %
Net gain (loss) on derivatives not designated as hedges	(64)	(31)	(33)	(106)%
Other	5	5	—	— %
Total domestic revenues	$2,368	$1,855	$513	28 %
Total international revenues	$117	$113	$4	4 %
Total revenues	$2,485	$1,968	$517	26 %

Domestic Revenues

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

- $95 million increase in natural gas sales is primarily due to $132 million related to higher sales prices partially offset by $34 million related to lower production sales volumes. The decrease in our production sales volumes is due to the impact of the sale of a portion of our working interests to Legacy during second-quarter 2014. Natural gas production from the Piceance Basin represents approximately 74 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for the nine months ended September 30, 2014 and 2013:

	Nine months ended September 30, 2014	2013
Natural gas sales (per Mcf) (a)	$3.68	$3.08
Impact of net cash received (paid) related to settlement of derivatives (per Mcf) (b)	(0.21)	(0.10)
Natural gas net price including derivative settlements (per Mcf)	$3.47	$2.98
Natural gas production sales volumes (MMcf)	212,117	223,262
Per day natural gas production sales volumes (MMcf/d)	777	818

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(a) Includes $0.02 per Mcf impact of net cash received on derivatives designated as hedges for the nine months ended September 30, 2013.

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

- $156 million increase in oil and condensate sales reflects increased production sales volumes partially offset by lower sales prices for 2014 compared to 2013. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin where the volumes were 18.2 MBbls per day for the first nine months 2014 compared to 12.6 MBbls per day for the same period in 2013. The San Juan Basin also had production of 2.9 MBbls per day for 2014 related to the Gallup Sandstone development. The following table reflects oil and condensate production prices and volumes for the nine months ended September 30, 2014 and 2013:

	Nine months ended September 30, 2014	2013
Oil sales (per barrel)	$86.47	$92.18
Impact of net cash received (paid) related to settlement of derivatives (per barrel) (a)	(2.07)	1.44
Oil net price including derivative settlements (per barrel)	$84.40	$93.62
Oil and condensate production sales volumes (MBbls)	6,269	4,183
Per day oil and condensate production sales volumes (MBbls/d)	23.0	15.3

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

- Natural gas liquids sales remained flat as the increase in NGL prices was offset by lower production volumes 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 nine months ended September 30, 2014 and 2013:

	Nine months ended September 30, 2014	2013
NGL sales (per barrel)	$35.16	$29.88
Impact of net cash received (paid) related to settlement of derivatives (per barrel) (a)	(0.05)	0.03
NGL net price including derivative settlements (per barrel)	$35.11	$29.91
NGL production sales volumes (MBbls)	4,786	5,607
Per day NGL production sales volumes (MBbls/d)	17.5	20.5

(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 nine months ended September 30, 2014 and 2013:

	Nine months ended September 30, 2014 % of barrel	$/gallon	2013 % of barrel	$/gallon
Ethane	31%	$0.29	39%	$0.27
Propane	32%	$1.13	29%	$0.88
Iso-Butane	9%	$1.33	8%	$1.41
Normal Butane	8%	$1.29	7%	$1.38
Natural Gasoline	20%	$2.13	17%	$2.14

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- $295 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 primarily during the first quarter of 2014. The increase in the sales price was greater than the increase in the purchase price as reflected in the $122 million increase in related gas management costs and expenses, discussed below. The increase in gas management revenues was also partially offset by a $102 million unfavorable change in net gain (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 Consolidated Statements of Operations, and is discussed below.
- $33 million unfavorable change in net gain (loss) on derivatives not designated as hedges primarily reflects $115 million unfavorable change realized on gas management derivatives and $43 million increase in loss realized on derivatives for our production, primarily natural gas and crude. The unfavorable changes were partially offset by a $112 million favorable change in unrealized gains (losses) on derivatives related to production, primarily natural gas and crude, and a $13 million favorable change in the unrealized portion of gas management derivatives.

International Revenues

International revenues increased primarily due to increased oil sales from our Colombian operations partially offset by less benefits realized from the government hydrocarbon subsidy program in Argentina for the nine months ended September 30, 2014 compared to the same period in 2013.

Cost and operating expense and operating income (loss) analysis

	Nine months ended September 30,		Favorable (Unfavorable)	Favorable (Unfavorable) %
	2014	2013	$ Change	Change
	(Millions)			
Domestic costs and expenses:				
Lease and facility operating	$182	$170	$(12)	(7)%
Gathering, processing and transportation	249	262	13	5%
Taxes other than income	100	77	(23)	(30)%
Gas management, including charges for unutilized pipeline capacity	788	666	(122)	(18)%
Exploration	97	55	(42)	(76)%
Depreciation, depletion and amortization	596	637	41	6%
Impairment of costs of acquired unproved reserves	—	19	19	100%
Loss on sale of working interests in the Piceance Basin	196	—	(196)	NM
General and administrative	208	198	(10)	(5)%
Other—net	6	10	4	40%
Total domestic costs and expenses	$2,422	$2,094	$(328)	(16)%
International costs and expenses:				
Lease and facility operating	$26	$26	$—	—%
Gathering, processing and transportation	1	2	1	50%
Taxes other than income	21	18	(3)	(17)%
Exploration	4	4	—	—%
Depreciation, depletion and amortization	31	25	(6)	(24)%
General and administrative	11	11	—	—%
Other—net	3	—	(3)	NM
Total international costs and expenses	$97	$86	$(11)	(13)%
Total costs and expenses	$2,519	$2,180	$(339)	(16)%
Domestic operating income (loss)	$(54)	$(239)	$185	77%
International operating income	$20	$27	$(7)	(26)%

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:

- $12 million increase in lease and facility operating expenses primarily relates to the impact of increased production in the Williston and San Juan Basins in relation to our overall portfolio. Lease and facility operating expense averaged $0.65 per Mcfe for the nine months ended September 30, 2014 compared to $0.60 for the same period in 2013.
- $13 million decrease in gathering, processing and transportation expenses primarily related to lower volumes and approximately $5 million recognized during the nine months ended September 30, 2014 related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company. Gathering, processing and transportation charges averaged $0.89 per Mcfe for 2014 and $0.93 per Mcfe for 2013. Excluding the impact of the refund, the gathering, processing and transportation expenses would have averaged $0.92 for the nine months ended September 30, 2014.
- $23 million increase in taxes other than income primarily relates to increased oil production volumes and higher natural gas prices. Taxes other than income averaged $0.36 per Mcfe for the nine months ended September 30, 2014 compared to $0.27 per Mcfe for the same period in 2013.
- $122 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. Additionally in 2014, we recognized approximately

$11 million related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company. Also included in gas management expenses are $44 million for the nine months ended September 30, 2014 and 2013 for unutilized pipeline capacity.

- $42 million increase in exploration expenses primarily relates to impairments of exploratory area well costs and impairments of unproved leasehold costs in exploratory plays for which management no longer intends to continue exploratory activities (see Note 4 of Notes to Consolidated Financial Statements).
- $41 million decrease in depreciation, depletion and amortization primarily due to the previously discussed lower natural gas production volumes and the impact of impairments taken in 2013 in the Appalachia Basin. During the nine months ended September 30, 2014, our depreciation, depletion and amortization averaged $2.14 per Mcfe compared to an average $2.26 per Mcfe for the same period in 2013.
- $19 million property impairment of cost of acquired unproved reserves in the Kokopelli area of the Piceance Basin in 2013.
- $196 million loss on the sale of a portion of our working interests in certain Piceance Basin wells (see Note 4 of Notes to Consolidated Financial Statements).
- $10 million increase in general and administrative expenses due to approximately $10 million related to costs associated with an early exit program offered during 2014. General and administrative expenses averaged $0.75 per Mcfe for the nine months ended September 30, 2014 compared to $0.70 per Mcfe for the same period in 2013. Excluding the impact of the early exit program costs, the average expense for the nine months ended September 30, 2014 would have been $0.71 per Mcfe.

International costs

International costs and expenses increased primarily due to an increase in depreciation, depletion and amortization related to increased oil volumes.

Consolidated results below operating income (loss)

	Nine months ended September 30,		Favorable (Unfavorable)	Favorable (Unfavorable) %
	2014	2013	$ Change	Change
	(Millions)			
Consolidated operating income (loss)	$(34)	$(212)	$178	84%
Interest expense	(88)	(82)	(6)	(7)%
Interest capitalized	1	1	—	—%
Investment income and other	12	17	(5)	(29)%
Income (loss) from continuing operations before income taxes	(109)	(276)	167	61%
Provision (benefit) for income taxes	(31)	(79)	(48)	(61)%
Income (loss) from continuing operations	(78)	(197)	119	60%
Income (loss) from discontinued operations	30	(10)	40	NM
Net income (loss)	(48)	(207)	159	77%
Less: Net income (loss) attributable to noncontrolling interests	7	5	2	40%
Net income (loss) attributable to WPX Energy, Inc.	$(55)	$(212)	$157	74%

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

Benefit for income taxes changed unfavorably in 2014 compared to 2013. See Note 7 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods. We recorded an additional $9 million of deferred tax expense in the first quarter of 2014 to accrue for the impact of new legislation enacted by the state of New York on March 31, 2014. Income taxes in 2013 include a $9 million deferred tax provision related to the increase in a valuation allowance on certain state deferred tax assets. Income taxes in 2013 also included a $10 million provision related to the impact of the new capital tax law in Argentina.

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The change in income (loss) from discontinued operations was primarily due to an increase in natural gas sales related to higher sales prices, a decrease in depreciation, depletion and amortization in 2014, and an accrual for litigation of $7 million in 2013. These increases were partially offset by lower production sales volumes.

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 "Credit Facility Agreement"). 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 approximately $1.8 billion, including acquisition capital, 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 September 30, 2014 is $27 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 leasehold acreage; and
- Reduced access to our credit facility.

Liquidity

Based on our forecasted levels of cash flow from operations and other sources of liquidity, we expect to have sufficient liquidity to manage our businesses throughout 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.

Subsequent to September 30, 2014, we amended and restated the Credit Facility Agreement, hereafter referred to as the "New Credit Facility Agreement". The terms of the New Credit Facility Agreement are materially the same as our Credit Facility Agreement, except that the New Credit Facility Agreement matures on October 28, 2019, the letters of credit sublimit is $750 million and we changed the Applicable Rates and revised our financial covenants as set forth below.

Under the New Credit Facility Agreement, when our Index Debt is not rated BBB- or better by S&P or Baa3 or better by Moody’s and not less than BB+ or Ba1 by the other such agency, we will be required to maintain a ratio of Consolidated Net Indebtedness (as defined in the New Credit Facility Agreement) to Consolidated EBITDAX (as defined in the New Credit Facility Agreement) of not greater than 3.75 to 1.00. Consolidated Net Indebtedness includes a reduction attributable to unrestricted cash and cash equivalents not to exceed $50 million. Consolidated EBITDAX will be calculated for the four fiscal quarters ending on the last day of any fiscal quarter for which financial statements have been or were required to be delivered. Additionally, the ratio of Consolidated Indebtedness (as defined in the New Credit Facility Agreement) to Consolidated Total Capitalization (defined as Consolidated Indebtedness plus Consolidated Net Worth) will not be permitted to be greater than 60 percent and will be applicable for the life of the agreement. During a Downgrade Period (as defined in the New Credit Facility Agreement), we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the New Credit Facility Agreement, to Consolidated Indebtedness ratio of at least 1.25 to 1.00 for fiscal periods ending on or prior to December 31, 2015, and 1.50 to 1.00 thereafter. This covenant will not apply after the occurrence of the Investment Grade Date, which is the first date after closing on which our Index Debt ratings are BBB- or better by S&P or Baa3 or better by Moody’s (without negative outlook or watch by either agency), provided that the other of the two ratings is at least BB+ by S&P or Ba1 by Moody’s.

Sources (Uses) of Cash

	Nine months ended September 30, 2014	2013
	(Millions)	
Net cash provided (used) by:		
Operating activities	$779	$520
Investing activities	(939)	(836)
Financing activities	132	273
Increase (decrease) in cash and cash equivalents	$(28)	$(43)

Operating activities

Our net cash provided by operating activities for the nine months ended September 30, 2014 increased from the same period in 2013 primarily due to the increase in our operating results related to higher natural gas and natural gas liquids prices and higher oil volumes.

Investing activities

Expenditures for domestic drilling and completion were $961 million and $691 million for the nine months ended September 30, 2014 and 2013, respectively. Domestic land acquisitions were $254 million and $44 million during the nine months ended September 30, 2014 and 2013, respectively. Included in the land acquisitions for the nine months ended September 30, 2014 was approximately $150 million related to the purchase of oil and natural gas properties in the San Juan Basin (see Note 5 of Notes to Consolidated Financial Statements). In addition, expenditures for international were $61 million and $43 million for the nine months ended September 30, 2014 and 2013, respectively. During the second quarter of 2014, we received proceeds of $337 million (subject to post-closing adjustments) for the sale of a portion of our working interests in certain Piceance Basin wells to Legacy (see Note 4 of Notes to Consolidated Financial Statements). In addition, we also received proceeds of approximately $50 million related to the sale of a portion of our working interests in the Piceance Basin as part of an agreement to farmout a portion of our Trail Ridge properties with TRDC LLC, a subsidiary of G2X Energy (see Note 5 of Notes to Consolidated Financial Statements).

Financing activities

During the third quarter of 2014, we issued $500 million of senior unsecured notes at an interest rate of 5.25 percent. We used the proceeds from this offering to repay borrowings under our revolving credit facility and for related transaction fees and expenses (see Note 6 of Notes to Consolidated Financial Statements).

Net cash provided by financing activities in 2013 primarily relates to borrowings under our revolving credit facility to partially fund capital expenditures during 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 September 30, 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 nine 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 9 and 10 of Notes to Consolidated Financial Statements.

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

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

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

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was a net liability of less than $1 million at September 30, 2014 and a net liability of $1 million at December 31, 2013. The value at risk for contracts held for trading purposes was less than $1 million at September 30, 2014 and 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 and crude oil purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $42 million at September 30, 2014 and a net liability of $64 million at December 31, 2013.

The value at risk for derivative contracts held for nontrading purposes was $19 million at both September 30, 2014 and 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 $17 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.

Third-Quarter 2014 Changes in Internal Controls
There have been no changes during the third 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 8 of Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 1A. Risk Factors
Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K, for the year ended December 31, 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 September 30, 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)
2.2**	Agreement and Plan of Merger, dated October 2, 2014, by and among Pluspetrol Resources Corporation, Pluspetrol Black River Corporation and Apco Oil and Gas International Inc. (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on October 7, 2014)
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)
4.2	Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.3	First Supplemental Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.4	Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)

10.5	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011)
10.6#	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
10.7	Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012) (1)
10.8	Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012) (1)

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

Exhibit No.	Description
10.9	First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011)
10.10	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on May 29, 2013) (1)
10.11	WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc.'s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011) (1)
10.12	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.13	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herin by reference to Exhibit 10.13 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014) (1)
10.14	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herin by reference to Exhibit 10.14 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014) (1)
10.15	Form of Stock Option Agreement between WPX Energy, Inc. and Section 16 Executive Officers (incorporated herin by reference to Exhibit 10.15 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014) (1)
10.16	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 Form 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 Form 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 Form 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 Form 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 Form 8-K filed with the SEC on May 2, 2014) (1)

Exhibit No.	Description
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 Form 8-K filed with the SEC on May 2, 2014) (1)
10.27	Form of Restricted Stock Unit Award between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.28	Separation and Release Agreement, dated July 28, 2014, between WPX Energy, Inc. and James J. Bender (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.29	WPX Energy Executive Severance Pay Plan (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on September 19, 2014) (1)
10.30	Amended and Restated Credit Agreement, dated as of October 28, 2014, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on November 3, 2014)
12*	Computation of Ratio of Earnings to Fixed Charges
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith

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

(1) Management contract or compensatory plan or arrangement

SIGNATURE

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

WPX Energy, Inc.
(Registrant)

By: /s/ J. KEVIN VANN
J. Kevin Vann
Senior Vice President and Chief Financial Officer (Principal Accounting Officer)

Date: November 5, 2014