UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the

Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): May 25, 2016

WPX Energy, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**1-35322**	**45-1836028**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

3500 One Williams Center, Tulsa, Oklahoma	**74172-0172**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (855) 979-2012

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240-14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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Item 8.01. Other Events

As noted in our Quarterly Report on Form 10-Q for the period ended March 31, 2016, we signed an agreement to sell WPX Energy Rocky Mountain, LLC that holds our Piceance Basin operations. The sale closed in April 2016. In our Form 10-Q for the quarterly period ended March 31, 2016, we reported the results of operations and financial position of our Piceance operations as discontinued operations.

In this filing, we have recast certain historical financial information originally included in our Annual Report on Form 10-K for the year ended December 31, 2015, to reflect the reclassification of our Piceance operations as discontinued operations.

The following items of the Form 10-K have been recast for the discontinued operations described above, to the extent applicable, and are filed or furnished as exhibits to this Current Report on Form 8-K:

- Exhibit 99.1
    - Item 6. Selected Financial Data
    - Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations
    - Item 7A. Quantitative and Qualitative Disclosures About Market Risk
    - Item 8. Financial Statements and Supplementary Data
- Exhibit 99.2. Schedule II — Valuation and Qualifying Accounts for each of the three years ended December 31, 2015
- Exhibit 101.INS — XBRL Instance Document.
- Exhibit 101.SCH — XBRL Taxonomy Extension Schema.
- Exhibit 101.CAL — XBRL Taxonomy Extension Calculation Linkbase.
- Exhibit 101.DEF — XBRL Taxonomy Extension Definition Linkbase.
- Exhibit 101.LAB — XBRL Taxonomy Extension Label Linkbase.
- Exhibit 101.PRE — XBRL Taxonomy Extension Presentation Linkbase.

The recast items of the Form 10-K described above have been updated for discontinued operations. We have not otherwise updated for activities or events occurring after the date these items were originally presented other than those disclosed in Note 3 and Note 16 of Notes to Consolidated Financial Statements. This Current Report on Form 8-K should be read in conjunction with our Quarterly Report on Form 10-Q for the period ended March 31, 2016.

FORWARD-LOOKING STATEMENTS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

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," "targets," "planned," "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 oil and natural gas reserves;
- reserve potential;
- development drilling potential;
- cash flow from operations or results of operations;
- acquisitions or divestitures;
- seasonality of our business; and
- crude oil, natural gas and 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 oil and natural gas reserves), market demand, volatility of prices and the availability and cost of capital;
- inflation, interest rates, fluctuation in foreign exchange and general economic conditions (including future disruptions and volatility in the global credit markets and the impact of these events on our customers and suppliers);
- the strength and financial resources of our competitors;
- development of alternative energy sources;
- the impact of operational and development hazards;
- costs of, changes in, or the results of laws, government regulations (including climate change regulation and/or potential additional regulation of drilling and completion of wells), environmental liabilities, litigation and rate proceedings;
- changes in maintenance and construction costs;
- changes in the current geopolitical situation;
- our exposure to the credit risk of our customers;
- risks related to strategy and financing, including restrictions stemming from our debt agreements, future changes in our credit ratings and the availability and cost of credit;
- risks associated with future weather conditions;
- acts of terrorism;
- other factors described in "Management's Discussion and Analysis of Financial Condition and Results of Operations"; and

- additional risks described in our filings with the Securities and Exchange Commission ("SEC").

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

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

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

Item 9.01. Financial Statements and Exhibits

(a) None

(b) None

(c) None

(d) Exhibits

Exhibit No.	Description
23.1*	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP
99.1*	Selected Financial Data, Management's Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures About Market Risk, and Financial Statements and Supplementary Data (Part II, Items 6, 7, 7A, and 8 of our Annual Report on Form 10-K for the year ended December 31, 2015)
99.2*	Schedule II — Valuation and Qualifying Accounts for each of the three years ended December 31, 2015
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* Filed herewith.

SIGNATURE

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

WPX ENERGY, INC.
(Registrant)

By: /s/ Stephen L. Faulkner

Stephen L. Faulkner
Controller
(Principal Accounting Officer)

Date: May 25, 2016

INDEX TO EXHIBITS

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* Filed herewith.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the following Registration Statements:

(1) Registration Statement (Form S-3 No 333-208552) and related Prospectus of WPX Energy, Inc. pertaining to the registration of 40,000,000 shares of its common stock

(2) Registration Statement (Form S-8 No 333-204355) pertaining to the WPX Energy, Inc. 2013 Incentive Plan, as amended effective May 21, 2015

(3) Registration Statement (Form S-3 No 333-198523) and related Prospectus of WPX Energy, Inc. pertaining to the registration of debt securities

(4) Registration Statement (Form S-3 No 333-197905) and related Prospectus of WPX Energy, Inc. pertaining to the registration of 481,157 shares of its common stock

(5) Registration Statement (Form S-8 No 333-188767) pertaining to the WPX Energy, Inc. 2013 Incentive Plan

(6) Registration Statement (Form S-8 No 333-178388) and the related post-effective amendment No. 1 pertaining to the WPX Energy, Inc. 2011 Incentive Plan and the WPX Energy, Inc. 2011 Employee Stock Purchase Plan

of our reports dated February 25, 2016, except for the effects of discontinued operations as discussed in Note 3 and Note 16, as to which the date is May 25, 2016, with respect to the consolidated financial statements and schedule of WPX Energy, Inc. and our report dated February 25, 2016, with respect to the effectiveness of internal control over financial reporting of WPX Energy, Inc., included in this Current Report on Form 8-K.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
May 25, 2016

Item 6. *Selected Financial Data*

The following financial data at December 31, 2015 and 2014 , and for each of the three years ended December 31, 2015 , 2014 and 2013 should be read in conjunction with the other financial information included in this Exhibit 99.1 of this Form 8-K. All other financial data has been prepared from our accounting records.

The financial information for 2011 may not necessarily reflect our financial position, results of operations and cash flows as if we had operated as a stand-alone public company during 2011. Accordingly, our results for 2011 should not be relied upon as an indicator of our future performance.

	Years Ended December 31,				
	2015	2014	2013	2012	2011
Statement of operations data:	(Millions, except per share amounts)				
Revenues	$ 1,366	$ 2,523	$ 1,505	$ 1,981	$ 2,125
Income (loss) from continuing operations(a)	$ (4)	$ 256	$ (1,005)	$ (2)	$ (46)
Income (loss) from discontinued operations(b)	(1,722)	(85)	(186)	(209)	(246)
Net income (loss)	(1,726)	171	(1,191)	(211)	(292)
Less: Net income attributable to noncontrolling interests	1	7	(6)	12	10
Net income (loss) attributable to WPX Energy, Inc.	$ (1,727)	$ 164	$ (1,185)	$ (223)	$ (302)
Less: Dividends on preferred stock	9	—	—	—	—
Net income (loss) attributable to WPX Energy, Inc. common stockholders	(1,736)	164	(1,185)	(223)	(302)
Amounts attributable to WPX Energy, Inc.:					
Income (loss) from continuing operations	$ (13)	$ 256	$ (993)	$ (2)	$ (46)
Income (loss) from discontinued operations	$ (1,723)	$ (92)	$ (192)	$ (221)	$ (256)
Basic earnings (loss) per common share:					
Income (loss) from continuing operations	(0.06)	1.26	(4.95)	(0.01)	(0.23)
Income (loss) from discontinued operations	(7.36)	(0.45)	(0.96)	(1.11)	(1.31)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	(0.06)	1.24	(4.95)	(0.01)	(0.23)
Income (loss) from discontinued operations	(7.36)	(0.44)	(0.96)	(1.11)	(1.31)

	As of December 31,				
	2015	2014	2013	2012	2011
Balance sheet data:	(Millions)				
Long-term debt(c)	$ 3,189	$ 2,260	$ 1,895	$ 1,483	$ 1,480
Total assets	$ 8,393	$ 8,896	$ 8,508	$ 9,536	$ 10,534
Total stockholder's equity	$ 3,535	$ 4,319	$ 4,109	$ 5,268	$ 5,678
Total equity, including noncontrolling interests	$ 3,535	$ 4,428	$ 4,210	$ 5,371	$ 5,759

(a) Income (loss) from continuing operations includes significant pre-tax items comprised of the following:

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(Millions)				
Impairment of producing properties and costs of acquired unproved reserves	$ —	$ 15	$ 772	$ 48	$ —
Impairment of unproved leasehold property	$ —	$ 41	$ 317	$ —	$ —
Impairment of equity method investment	$ —	$ —	$ 20	$ —	$ —
Impairment of exploratory area well costs and dry hole costs	$ 24	$ 21	$ 3	$ 1	$ 61
Net (gain) loss on sales of assets	$ (349)	$ —	$ —	$ —	$ —

See Note 5 of Notes to Consolidated Financial Statements for further discussion of the impairments and asset sales in 2015 , 2014 and 2013 .

(b) Income (loss) from discontinued operations includes the results of holdings in the Piceance Basin, holdings in the Powder River Basin, holdings in the Barnett Shale and Arkoma Basin and Apco Oil and Gas International Inc. Significant components included in income (loss) from discontinued operations are comprised of the following:

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(Millions)				
Piceance pre-tax impairments, including impairment of producing properties, costs of acquired unproved reserves and exploratory area well costs	$ 2,334	$ 72	$ 88	$ 75	$ —
Powder River pre-tax impairments	$ 16	$ 45	$ 192	$ 102	$ 367
Barnett Shale pre-tax impairment	$ —	$ —	$ —	$ —	$ 180
Net pre-tax gain on divestments	$ (26)	$ —	$ —	$ (38)	$ —
Powder River gain on sale of deep rights leasehold	$ —	$ —	$ (36)	$ —	$ —
Loss on sale of working interests in the Piceance Basin	$ —	$ 196	$ —	$ —	$ —

See Note 3 of of Notes to Consolidated Financial Statements for further discussion of discontinued operations in 2015 , 2014 and 2013 .

(c) The balance sheet data includes the retrospective application of ASU 2015-03 and ASU 2015-15, *Simplifying the Presentation of Debt Issuance Costs.* The adoption of this standard resulted in the reclassification of unamortized debt issuance costs related to the Company's senior unsecured notes from “Other noncurrent assets” to “Long-term debt” within its consolidated balance sheets. See Note 1 of Notes to Consolidated Financial Statements for further discussion.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

General and Basis of Presentation

We are an independent oil and natural gas exploration and production company engaged in the exploitation and development of long-life unconventional properties. We are focused on profitably exploiting, developing and growing our oil positions in the Williston Basin in North Dakota and the Permian and San Juan Basins in the southwestern United States. We also have a natural gas position in the San Juan Basin. Until January 2015, we had significant operations in the Appalachian Basin in Pennsylvania.

On August 17, 2015, we completed the acquisition of privately-held RKI Exploration & Production, LLC ("RKI") (the "Acquisition") expanding our operations into the Permian Basin in New Mexico and Texas. See Note 2 of Notes to Consolidated Financial Statements for a further discussion regarding the Acquisition.

In conjunction with our exploration and development activities, we engage in sales and marketing activities that include the sale of our oil, natural gas and NGL production, along with third-party purchases and sales of oil and natural gas, which include oil and natural gas purchased from working interest owners in operated wells and other area third-party producers. Our sales and marketing activities also include the management of various natural gas related contracts such as transportation, storage and related price risk management activities. Revenues associated with the sale of our production are recorded in product revenues. The revenues and expenses related to other marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

In addition to the operations discussed above, we had operations in the Piceance Basin in Colorado. On February 8, 2016, we signed an agreement to sell our wholly owned subsidiary WPX Energy Rocky Mountain LLC, to Terra Energy Partners LLC ("Terra"), for $910 million and closed the transaction April 8, 2016. WPX Energy Rocky Mountain LLC holds our Piceance Basin operations. The agreement requires Terra to become financially responsible for approximately $104 million in transportation obligations held by our marketing company. Additionally, Terra will be assigned a portion of WPX's natural gas derivatives with a fair value of $82 million as of December 31, 2015. We also had operations for a portion of 2015 in the Powder River Basin in Wyoming, which were sold on September 1, 2015 and, until January 29, 2015, we had a 69 percent controlling interest in Apco Oil and Gas International Inc. ("Apco"), an oil and gas exploration and production company with activities in Argentina and Colombia. For all periods presented, the results of the Piceance Basin, Powder River Basin and Apco are reported as discontinued operations. See Note 3 of Notes to Consolidated Financial Statements for further discussion of our discontinued operations. Unless indicated otherwise, the following discussion relates to continuing operations.

The following discussion should be read in conjunction with the selected historical consolidated financial data and the consolidated financial statements and the related notes in Item 8 also included in this Exhibit 99.1 of this Form 8-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 in our 2015 Annual Report on Form 10-K, particularly in "Risk Factors" and "Forward-Looking Statements."

Overview

The following table presents our production volumes and financial highlights for 2015 , 2014 and 2013 :

	Years Ended December 31,		
	2015	2014	2013
Production Sales Volume Data(a):			
Oil (MBbls)	12,479	8,568	5,230
Natural gas (MMcf)	66,187	74,533	76,618
NGLs (MBbls)	2,412	898	452
Combined equivalent volumes (Mboe)(b)	25,922	21,888	18,451
Production Sales Volume Per Day(a):			
Oil (MBbls/d)	34.2	23.5	14.3
Natural Gas (MMcf/d)	181	204	210
NGL (MBbls/d)	6.6	2.5	1.2
Combined equivalent volumes (Mboe/d)	71.0	60.0	50.6
Financial Data (millions):			
Total revenues	$ 1,366	$ 2,523	$ 1,505
Operating income (loss)	$ 274	$ 526	$ (1,445)
Cash capital expenditures(c)	$ (1,124)	$ (1,807)	$ (1,154)
Cash expenditure activity(c)	$ (865)	$ (1,934)	$ (1,207)

(a) Excludes production from our discontinued operations.
(b) Mboe are converted using the ratio of one barrel of oil, condensate or NGL to six thousand cubic feet of natural gas.
(c) Includes capital expenditures related to discontinued operations of $266 million, $597 million and $412 million for the years ended December 31, 2015, 2014 and 2013, respectively, and excludes capital expenditures related to acquisitions.

Our 2015 operating results were $252 million unfavorable compared to 2014. The primary unfavorable impacts include $316 million lower production revenues, $165 million higher depreciation, depletion and amortization expense, $106 million lower net gas management margin, a $22 million charge associated with a contract termination in the first quarter of 2015 and a $23 million charge associated with gathering obligations in an area of the Appalachian Basin where we plugged and abandoned our remaining wells in the fourth quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements), and $23 million of acquisition costs in 2015. Favorable impacts to operating results include $349 million net gain on sales of assets in 2015 (see Note 5 of Notes to Consolidated Financial Statements) and $45 million in total from lower operating expenses, including lease and facility operating, gathering, processing and transportation, operating taxes and general and administrative expenses for 2015 compared to 2014.

Our 2014 operating results were $2.0 billion favorable compared to 2013. Favorable impacts include a $558 million favorable change in derivatives not designated as hedges, a $316 million decrease in exploration expenses (including exploratory well costs and unproved leasehold impairments), $194 million higher oil sales and $23 million higher natural gas sales. Additionally, impairments of proved producing properties were $15 million in 2014 as compared to impairments of proved producing properties and capitalized cost of acquired unproved reserves of $772 million in 2013 (see Note 5 of Notes to Consolidated Financial Statements).

Outlook

While the significant declines in commodity prices are challenging to the oil and gas industry as evidenced by the further reduction in capital plans among our peers, reductions in workforces across the industry and the concerns about liquidity, we are committed to our long-term strategy. In late 2014, we communicated our long term strategy to simplify our geographic focus and expand returns, margins and cash flow (on a per unit basis) over the next five years. However, we must remain flexible to adjust to market conditions. At the time of that communication, commodity prices were significantly higher than current commodity prices. This decrease in the commodity prices challenges our goals of returns, margins and cash flows in the next five years, however, we remain laser focused on addressing the things that are within our control that will contribute to these measures and the sustainability of this company. Since 2014, we have made the necessary moves that we believe put us in a position to realize our long term goals as prices recover and sustain us through the lowest oil prices in over a decade. During 2015, we made significant progress toward simplifying our geographic focus with the completion of the sales of our international interests in Argentina and Colombia, a significant portion of our Appalachian Basin operations and our Powder River Basin properties. As we narrowed our geographic focus, we remained aware of opportunities that could arise because of the market conditions in 2015 that would be complementary to our portfolio. As such, we acquired privately-held RKI Exploration & Production, LLC in August 2015 which provided an entry into the Permian-Delaware Basin, a significant resource play with multiple horizons of hydrocarbons in place. The asset scale and concentrated acreage position will allow for efficient, low-cost development activities over a number of years that will provide additional optionality to our portfolio and a more balanced commodity mix. A substantial portion of our future capital spending will be allocated to the Permian-Delaware Basin where expected returns are attractive compared to our other assets.

As we continue our transformation, we have the opportunity to improve our cost structure and ensure that our organization is in alignment with our growth objectives. Throughout 2015, we reduced costs through reduced drilling times, efficient use of pad design and completion activities, and worked with our vendors to lower costs on goods and services. During the first and second quarters of 2015, we reduced our then company-wide workforce by approximately 8 percent and consolidated most of our regional office staff in Denver, Colorado, with personnel at the Company's headquarters in Tulsa, Oklahoma. As a result of the Acquisition, we added to our general and administrative costs, however, we expect these costs to reduce over time as we integrate the operations and the RKI corporate office in Oklahoma City. In February 2016, we announced our plans to close the Oklahoma City office by mid-year 2016. Also our sale of the Piceance Basin will necessitate further reductions to our cost structure. We will continue to further align our organizational size to achieve an optimal workforce conducive to the current pricing environment and future growth.

As we have made steps towards our long term strategy, we must also address the near term challenges to WPX and the industry in 2016 and 2017. Lower commodity prices will impact the overall industry’s 2016 capital plans and revolver availability and liquidity. For WPX, the lower market prices will be partially mitigated as approximately three-fourths of our 2016 anticipated oil volumes are hedged well above current prices. The company now has 29,380 barrels of oil per day hedged at $60.85 per barrel in 2016. For 2017, WPX has 15,544 Bbl per day of oil hedged at $54.24 per barrel.

Liquidity will also be of major importance to the industry as many companies face lower cash flows from operations and potentially lower availability under revolving credit agreements as borrowing base re-determinations occur in early 2016. Because of the Acquisition in 2015, we increased our leverage in 2015 but we established goals of debt reduction via asset sales. In total, we targeted $800 million to $1 billion in asset sales. For 2015, we targeted $400 million to $500 million of asset sales which was exceeded with the Powder River divestiture, the sale of the gathering assets in the Williston Basin and the signing of the sale of gathering assets in the San Juan Basin. In 2016, WPX signed an agreement for the disposition of all of its assets in the Piceance Basin for $910 million and subsequently closed the transaction in April 2016. These targeted divestitures will provide proceeds to reduce our debt and/or provide cash for liquidity. Through February 25, 2016, we reduced our long-term debt (excluding amounts outstanding under our Credit Agreement) by repurchasing approximately $96 million in notes - or 24 percent - of a $400 million maturity due in early 2017 at an overall discount to par. Approximately $45 million of the $96 million had been repurchased as of December 31, 2015. Subsequent to February 25, 2016, we redeemed an additional $87 million after we tendered for the remaining outstanding 5.250% senior notes due in 2017 (see Note 16 of Notes to Consolidated Financial Statements). Aside from the revolver, which matures in the October of 2019, the company’s next debt maturity does not occur until 2020. See “Management's Discussion and Analysis of Financial Condition and Liquidity.”

In 2016, we will continue to focus on lowering costs through reduced drilling times, efficient use of pad design and completion activities, and working with our vendors to lower costs on goods and services. We will continue to challenge the level of our general and administrative costs.

Our 2016 drilling and completion capital program is expected to range from $350 million to $450 million. For the full-year 2016, we expect to spend $175 million to $225 million in the Permian Basin while running an average of 3 rigs to develop our acreage. We expect to spend $100 million to $125 million in the Williston Basin and deploy one rig. We expect to spend $75 million to $90 million in the San Juan Basin, primarily in the Gallup Sandstone with one rig.

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

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

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

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

With the exception of potential impairments, we continue to address certain of these risks through utilization of commodity hedging strategies, disciplined investment strategies and maintaining adequate liquidity. In addition, we use master netting agreements and collateral requirements with our counterparties to reduce credit risk and liquidity requirements. Further, we continue to monitor the long-term market outlooks and forecasts for potential indicators of needed changes to our forecasted oil and natural gas prices. If forecasted oil and natural gas prices were to decline, we would need to review the producing properties net book value for possible impairment. If impairments were required, the charges could be significant and may impact our financial ratios within our Credit Agreement covenants. The net book value of our predominantly oil proved properties is $3.9 billion and the net book value of our predominantly natural gas proved properties is $350 million. In addition, the net book value associated with unproved leasehold is approximately $2.3 billion and is primarily associated with our Permian Basin properties. See our discussion of impairment of long-lived assets in our critical accounting estimates discussion later in this section.

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 (see Note 15 of Notes to Consolidated Financial Statements). We chose not to designate our derivative contracts associated with our future production as cash flow hedges for accounting purposes. We have the following contracts as of February 24, 2016 , shown at weighted average volumes and basin-level weighted average prices:

Crude Oil	**2016**		**2017**	
	Volume (Bbls/d)	**Weighted Average Price ($/Bbl)**	**Volume (Bbls/d)**	**Weighted Average Price ($/Bbl)**
Fixed-price—WTI	29,380	$60.85	15,544	$54.24
Swaptions—WTI	1,257	$57.15	3,264	$51.22
Fixed Price Calls— WTI	1,243	$55.75	2,000	$57.10
Basis Swaps— Midland-Cushing	5,000	$(0.45)	—	$—

Natural Gas	**2016**		**2017**	
	Volume (BBtu/d)	**Weighted Average Price ($/MMBtu)**	**Volume (BBtu/d)**	**Weighted Average Price ($/MMBtu)**
Fixed-price—Henry Hub	213	$3.79	—	$—
Swaptions—Henry Hub	—	$—	65	$4.19
Fixed Price Calls—Henry Hub	—	$—	16	$4.50
Basis swaps—NGPL	5	$(0.23)	—	$—
Basis swaps—San Juan	100	$(0.18)	33	$(0.16)
Basis swaps—Rockies	163	$(0.21)	50	$(0.21)
Basis swaps—SoCal	45	$(0.01)	10	$—
Basis swaps—Permian	33	$(0.17)	—	$—

As part of the agreement to sell our Piceance Basin operations to Terra Energy Partners LLC, WPX novated to WPX Energy Rocky Mountain, LLC fixed price Henry Hub swaps totaling 265 BBtu per day in April-December 2016 at a weighted average price of $3.463 per MMBtu and 2017 fixed price Henry Hub swaps totaling 93 BBtu per day at a weighted average price of $3.22 per MMBtu. These derivatives are not included in the tables above. In addition to the derivatives mentioned above and pursuant to the sales agreement, WPX Energy Rocky Mountain, LLC executed fixed price Henry Hub swaps in 2016 totaling 279,267 BBtu from April 2016 through 2020 at a weighted average price of $2.77 per MMBtu.

Results of Operations

Operations of our company include oil, natural gas and NGL development, production and gas management activities primarily located in Texas, North Dakota, New Mexico and Colorado. Our development and production techniques specialize in production from tight-sands and shale formations primarily in the Permian, Williston and San Juan Basins. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation, storage and related derivatives coupled with the sale of our commodity volumes.

2015 vs. 2014

Revenue Analysis

	Years ended December 31, 2015	Years ended December 31, 2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Revenues:				
Oil sales	$ 494	$ 669	$ (175)	(26)%
Natural gas sales	138	282	(144)	(51)%
Natural gas liquid sales	23	20	3	15 %
Total product revenues	655	971	(316)	(33)%
Gas management	286	1,110	(824)	(74)%
Net gain (loss) on derivatives not designated as hedges	418	434	(16)	(4)%
Other	7	8	(1)	(13)%
Total revenues	$ 1,366	$ 2,523	$ (1,157)	(46)%

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

- $175 million decrease in oil sales reflects $480 million related to lower sales prices partially offset by a $305 million increase related to increased sales volumes for 2015 compared to 2014. The increase in production sales volumes primarily relates to Permian Basin volumes since the Acquisition and continued development drilling in the Williston Basin and Gallup Sandstone in the San Juan Basin. In the Williston and San Juan Basins, volumes were 21.8 Mbbls per day and 8.9 Mbbls per day, respectively for 2015 compared to 19.5 Mbbls per day and 3.9 Mbbls per day, respectively, for 2014. Volumes in the Permian Basin since the Acquisition date were 9.2 Mbbls per day. The following table reflects oil and condensate production prices and volumes for 2015 and 2014.

	Years ended December 31, 2015	Years ended December 31, 2014
Oil sales (per barrel)	$ 39.61	$ 78.09
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	31.21	2.17
Oil net price including all derivative settlements (per barrel)	$ 70.82	$ 80.26
Oil production sales volumes (Mbbls)	12,479	8,568
Per day oil production sales volumes (Mbbls/d)	34.2	23.5

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

- $144 million decrease in natural gas sales is primarily due to $113 million related to lower sales prices and $31 million related to lower production sales volumes for 2015 compared to 2014. The decrease in our production sales volumes is due in part to the impact of the sale of Appalachian Basin assets in the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements) partially offset by an increase in production sales volumes in the San Juan Basin in 2015 and the Permian Basin since the Acquisition date. The following table reflects natural gas production prices and volumes for 2015 and 2014.

	Years ended December 31,	
	2015	2014
Natural gas sales (per Mcf)	$ 2.08	$ 3.78
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	3.93	(0.37)
Natural gas net price including all derivative settlements (per Mcf)	$ 6.01	$ 3.41
Natural gas production sales volumes (MMcf)	66,187	74,533
Per day natural gas production sales volumes (MMcf/d)	181	204

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

- $3 million increase in natural gas liquids sales is primarily due to $35 million related to higher production sales volumes substantially offset by $32 million related to lower NGL sales prices for 2015 compared to 2014. The following table reflects NGL production prices and volumes for 2015 and 2014.

	Years ended December 31,	
	2015	2014
NGL sales (per barrel)	$ 9.39	$ 22.94
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	—	7.81
NGL net price including all derivative settlements (per barrel)	$ 9.39	$ 30.75
NGL production sales volumes (Mbbls)	2,412	898
Per day NGL production sales volumes (Mbbls/d)	6.6	2.5

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

- $824 million decrease in gas management revenues primarily due to lower average prices on physical natural gas sales as well as lower natural gas sales volumes. The decrease in volumes primarily relates to the sale of a package of marketing contracts in the second quarter of 2015 and release of certain related firm transportation capacity in the first and second quarters of 2015 (see Note 5 of Notes to Consolidated Financial Statements). The decrease in the sales price was greater than the decrease in the purchase price as reflected in the $718 million decrease in related gas management costs and expenses, discussed below.
- $16 million unfavorable change in net gain (loss) on derivatives not designated as hedges primarily reflects a $77 million unfavorable change on derivatives related to our production partially offset by a $61 million favorable change on derivatives related to gas management. Settlements of our derivatives in 2015 totaled $650 million. We have a net derivative asset of $426 million as of December 31, 2015 of which approximately $363 million relates to 2016 production. As part of the closing of the Piceance divestiture, WPX will novate approximately $82 million of our net derivative assets as of December 31, 2015 to WPX Energy Rocky Mountain, LLC prior to close.

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

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2015	2014		
	(Millions)			
Costs and expenses:				
Lease and facility operating	$ 145	$ 143	$ (2)	(1)%
Gathering, processing and transportation	64	71	7	10 %
Taxes other than income	62	88	26	30 %
Gas management, including charges for unutilized pipeline capacity	261	979	718	73 %
Exploration	85	101	16	16 %
Depreciation, depletion and amortization	528	363	(165)	(45)%
Impairment of producing properties and costs of acquired unproved reserves	—	15	15	100 %
Net (gain) loss on sales of assets	(349)	—	349	NM
General and administrative	210	224	14	6 %
Acquisition costs	23	—	(23)	NM
Other—net	63	13	(50)	NM
Total costs and expenses	$ 1,092	$ 1,997	$ 905	45 %
Operating income (loss)	$ 274	$ 526	$ (252)	(48)%

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

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

- $2 million increase in lease and facility operating expenses primarily relates to higher oil production volumes and approximately $25 million related to the Permian Basin since the Acquisition date substantially offset by lower natural gas volumes due to the sales of a portion of our Appalachian Basin assets in the first quarter of 2015, as well as cost reduction efforts across our basins. Lease and facility operating expense in 2015 averaged $5.59 per Boe compared to $6.51 per Boe during 2014.
- $7 million decrease in gathering, processing and transportation expenses primarily relates to lower excess gathering capacity expense which was $8 million and $13 million in 2015 and 2014, respectively. Gathering, processing and transportation charges averaged $2.48 per Boe for 2015 and $3.25 per Boe for 2014. Due to the recently completed sale of our Williston Basin gathering system and the expected sale of our San Juan Basin gathering system, we expect gathering, processing and transportation expenses to increase in future periods.
- $26 million decrease in taxes other than income primarily relates to lower oil prices, partially offset by higher oil production volumes. Our taxes other than income averaged $2.38 per Boe for 2015 compared to an average of $4.03 per Boe for 2014.
- $718 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, as previously discussed. Additionally in 2014, we recognized a loss of approximately $14 million on the release of future storage capacity commitments and approximately $4 million loss on the sale of related natural gas in storage partially offset by $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 $38 million and $57 million in 2015 and 2014, respectively, for unutilized pipeline capacity. Unutilized pipeline capacity expenses will be less in the future as a result of the charge included in discontinued operations (see Note 3 of Notes to Consolidated Financial Statements); however, we will continue to have cash outflows associated with these contracts. Similar charges related to transportation obligations are likely upon the closing of the sale of our Piceance Basin properties.
- $16 million decrease in exploration expenses primarily relates to a decrease in unproved leasehold property impairments, amortization and expiration 2015 compared to 2014 (see Note 5 of Notes to Consolidated Financial Statements).
- $165 million increase in depreciation, depletion and amortization expenses primarily due to a higher rate, higher oil production volumes and approximately $39 million related to the Permian Basin. The higher rate is due in part to our adjustment of the proved reserves used for the calculation of depletion and amortization to reflect the

impact of a decrease in the 12-month average price resulting in a $36 million addition to depreciation, depletion and amortization in 2015. Further decreases in the 12-month average price may result in additional increases in our depreciation, depletion and amortization expense. During 2015, our depreciation, depletion and amortization averaged $20.39 per Boe compared to an average $16.58 per Boe in 2014.

- $349 million net (gain) loss on sales of assets in 2015 primarily reflects $209 million from the sale of a package of marketing contracts and release of certain firm transportation capacity in the second quarter of 2015, $70 million from the sale of a North Dakota gathering system in the fourth quarter of 2015 and $69 million from the sale of a portion of our Appalachian Basin assets in the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).
- $14 million decrease in general and administrative expenses is primarily due to reduced employee and related costs as a result of headcount reductions and the absence of $10 million of costs associated with an early exit program offered in 2014 partially offset by approximately $15 million of severance and relocation costs associated with the workforce reduction and office consolidation announced during the first quarter of 2015. General and administrative expenses averaged $8.12 per Boe for 2015 compared to $10.24 per Boe for 2014. Excluding the severance and relocation costs in 2015 and the costs of the early exit program in 2014, general and administrative expenses would have averaged $7.52 per Boe for 2015 and $9.79 per Boe for 2014.
- $23 million of acquisition costs in 2015 related to the Acquisition (see Note 2 of Notes to Consolidated Financial Statements).
- $50 million increase in other expenses primarily relates to a $22 million charge associated with a contract termination in the first quarter of 2015 and a $23 million charge associated with gathering obligations in an area of the Appalachian Basin where we plugged and abandoned our remaining wells in the fourth quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).

Results below operating income (loss)

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2015	2014		
	(Millions)			
Operating income (loss)	$ 274	$ 526	$ (252)	(48)%
Interest expense	(187)	(123)	(64)	(52)%
Loss on extinguishment of acquired debt	(65)	—	(65)	NM
Investment income and other	(2)	1	(3)	NM
Income (loss) from continuing operations before income taxes	20	404	(384)	(95)%
Provision (benefit) for income taxes	24	148	124	84 %
Income (loss) from continuing operations	(4)	256	(260)	NM
Income (loss) from discontinued operations	(1,722)	(85)	(1,637)	NM
Net income (loss)	(1,726)	171	(1,897)	NM
Less: Net income (loss) attributable to noncontrolling interests	1	7	(6)	(86)%
Net income (loss) attributable to WPX Energy, Inc.	$ (1,727)	$ 164	$ (1,891)	NM

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

The increase in interest expense primarily relates to $35 million associated with the notes issued in the third quarter of 2015 and $16 million of fees associated with acquisition bridge financing arrangements related to the Acquisition. No borrowings were made under the acquisition bridge financing arrangements (see Note 2 of Notes to Consolidated Financial Statements).

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

The provision (benefit) for income taxes changed favorably due to lower income from continuing operations before income taxes in 2015 compared to 2014. See Note 9 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

The change in income (loss) from discontinued operations was primarily due to the Piceance Basin operations, which includes a $2.3 billion impairment in 2015, the completion of the sale of Apco in first-quarter 2015, a $15 million loss on the sale of the Powder River Basin and $187 million of expense recorded upon the exit of the Powder River Basin related to obligations under pipeline capacity, gathering and treating agreements, partially offset by $13 million received from the settlement of the escrow from a previous sales contract for the Powder River Basin assets for 2015 (see Note 3 of Notes to Consolidated Financial Statements).

2014 vs. 2013

Revenue Analysis

	Years ended December 31, 2014	Years ended December 31, 2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Revenues:				
Oil sales	$ 669	$ 475	$ 194	41%
Natural gas sales	282	259	23	9%
Natural gas liquid sales	20	10	10	100%
Total product revenues	971	744	227	31%
Gas management	1,110	882	228	26%
Net gain (loss) on derivatives not designated as hedges	434	(124)	558	NM
Other	8	3	5	167%
Total revenues	$ 2,523	$ 1,505	$ 1,018	68%

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

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

- $194 million increase in oil sales reflects a $303 million increase related to production sales volumes for 2014 compared to 2013 partially offset by a $109 million decrease related to lower sales prices. The increase in production sales volumes primarily relates to continued development drilling in the Williston Basin where the volumes were 19.5 Mbbls per day for 2014 compared to 13.2 Mbbls per day for 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 2014 and 2013.

	Years ended December 31, 2014	Years ended December 31, 2013
Oil sales (per barrel)	$ 78.09	$ 90.86
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	2.17	1.72
Oil net price including all derivative settlements (per barrel)	$ 80.26	$ 92.58
Oil production sales volumes (Mbbls)	8,568	5,230
Per day oil production sales volumes (Mbbls/d)	23.5	14.3

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

- $23 million increase in natural gas sales primarily reflects $30 million related to higher natural gas prices partially offset by a $7 million decrease related to lower production sales volumes for 2014 compared to 2013. The following table reflects natural gas production prices and volumes for 2014 and 2013.

	Years ended December 31,	
	2014	2013
Natural gas sales (per Mcf)(a)	$ 3.78	$ 3.38
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(b)	(0.37)	(0.27)
Natural gas net price including all derivative settlements (per Mcf)	$ 3.41	$ 3.11
Natural gas production sales volumes (MMcf)	74,533	76,618
Per day natural gas production sales volumes (MMcf/d)	204	210

(a) Includes $0.06 per Mcf impact of net cash received on derivatives designated as hedges for 2013.
(b) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.

- $10 million increase in natural gas liquids sales primarily reflects increased production sales volumes in 2014 compared to 2013. The following table reflects natural gas liquid production prices and volumes for 2014 and 2013.

	Years ended December 31,	
	2014	2013
NGL sales (per barrel)	$ 22.94	$ 21.95
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	7.81	1.24
NGL net price including all derivative settlements (per barrel)	$ 30.75	$ 23.19
NGL production sales volumes (Mbbls)	898	452
Per day NGL production sales volumes (Mbbls/d)	2.5	1.2

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

- $228 million increase in gas management revenues primarily due to higher average prices on physical natural gas sales. 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 $52 million increase in related gas management costs and expenses, discussed below.
- $558 million favorable change in net gain (loss) on derivatives not designated as hedges primarily reflects a $565 million favorable change in unrealized gains (losses) on derivatives related to production, primarily natural gas and crude, and $100 million favorable change in the unrealized portion of gas management derivatives. Our net derivative assets as of December 31, 2014 were $494 million. The favorable changes are partially offset by a $120 million of realized losses in 2014 on gas management derivatives.

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

	Years ended December 31,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2014	2013		
	(Millions)			
Costs and expenses:				
Lease and facility operating	$ 143	$ 109	$ (34)	(31)%
Gathering, processing and transportation	71	73	2	3 %
Taxes other than income	88	68	(20)	(29)%
Gas management, including charges for unutilized pipeline capacity	979	927	(52)	(6)%
Exploration	101	417	316	76 %
Depreciation, depletion and amortization	363	354	(9)	(3)%
Impairment of producing properties and costs of acquired unproved reserves	15	772	757	98 %
General and administrative	224	218	(6)	(3)%
Other—net	13	12	(1)	(8)%
Total costs and expenses	$ 1,997	$ 2,950	$ 953	32 %
Operating income (loss)	$ 526	$ (1,445)	$ 1,971	NM

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

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

- $34 million increase in lease and facility operating expenses primarily relates to the impact of increased oil production in the Williston and San Juan Basins. Lease and facility operating expense in 2014 averaged $6.51 per Boe compared to $5.94 per Boe during 2013.
- $2 million decrease in gathering, processing and transportation expenses primarily related to lower natural gas volumes. Also included in gathering, processing and transportation expenses are $13 million and $12 million in 2014 and 2013, respectively, of excess gathering capacity expense. Gathering, processing and transportation charges averaged $3.25 per Boe for 2014 and $3.99 per Boe for 2013.
- $20 million increase in taxes other than income primarily relates to increased oil production volumes. Our taxes other than income averaged $4.03 per Boe for 2014 compared to an average of $3.70 per Boe for 2013.
- $52 million increase in gas management expenses, primarily due to higher average prices on physical natural gas cost of sales. Additionally, in 2014 we recognized a loss of approximately $14 million on the release of future storage capacity commitments and approximately $4 million loss on the sale of related natural gas in storage partially offset by $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 $57 million and $61 million in 2014 and 2013, respectively, for unutilized pipeline capacity. Gas management expenses in 2013 also included $9 million related to the buyout of a transportation contract.
- $316 million decrease in exploration expenses primarily reflects lower unproved leasehold impairment, amortization and expiration expenses in 2014 compared to 2013. The unproved leasehold impairment in 2014 includes $41 million of impairments for unproved leasehold costs in exploratory areas where we no longer intend to continue exploration activities, while 2013 includes a $317 million impairment to fair value of leasehold in the Appalachian Basin. The decrease in unproved leasehold impairment, amortization and expiration expenses was partially offset by $16 million of impairments in other exploratory areas where management has determined to cease exploratory activities (see Note 5 of Notes to Consolidated Financial Statements).
- $9 million increase in depreciation, depletion and amortization expenses primarily due to the increase in oil production partially offset by lower natural gas production volumes and the impact of impairments taken in 2013 in the Appalachian Basin. During 2014, our depreciation, depletion and amortization averaged $16.58 per Boe compared to an average $19.16 per Boe in 2013.
- $15 million of property impairments in 2014 compared to $772 million in 2013 (see Note 5 of Notes to Consolidated Financial Statements).
- $6 million increase in general and administrative expenses in 2014 compared to 2013. Included in 2014 is $10 million related to a voluntary early exit program. General and administrative expenses averaged $10.24 per Boe

for 2014 compared to $11.77 per Boe for 2013. Excluding the costs of the early exit program in 2014, general and administrative expenses would have averaged $9.79 per Boe for 2014.

- Other expenses include rig release and standby fees of $16 million and $12 million for 2014 and 2013, respectively.

Results below operating income (loss)

	Years ended December 31, 2014	Years ended December 31, 2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$ 526	$ (1,445)	$ 1,971	NM
Interest expense	(123)	(108)	(15)	(14)%
Investment income, impairment of equity method investment and other	1	(19)	20	NM
Income (loss) from continuing operations before income taxes	404	(1,572)	1,976	NM
Provision (benefit) for income taxes	148	(567)	(715)	NM
Income (loss) from continuing operations	256	(1,005)	1,261	NM
Income (loss) from discontinued operations	(85)	(186)	101	54 %
Net income (loss)	171	(1,191)	1,362	NM
Less: Net income (loss) attributable to noncontrolling interests	7	(6)	13	NM
Net income (loss) attributable to WPX Energy, Inc.	$ 164	$ (1,185)	$ 1,349	NM

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

The increase in interest expense primarily relates to a higher amount outstanding on our revolver during 2014 compared to 2013 and the $500 million of notes issued in the third quarter of 2014.

Our investment income, impairment of equity method investment and other in 2013 includes a $20 million impairment related to an equity method investment in the Appalachian Basin.

The provision (benefit) for income taxes changed unfavorably due to income from continuing operations before income taxes in 2014 compared to a loss from continuing operations before income taxes in 2013. See Note 9 of Notes to Consolidated Financial Statements for a discussion of the effective tax rates compared to the federal statutory rate for both periods.

Income (loss) from discontinued operations includes the results of operations from the Piceance Basin, Powder River Basin and our former international segment (see Note 3 of Notes to Consolidated Financial Statements).

Management's Discussion and Analysis of Financial Condition and Liquidity

Overview and Liquidity

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

- as of December 31, 2015 , we maintained liquidity through cash, cash equivalents and available credit capacity under our credit facility; and
- our credit exposure to derivative counterparties is partially mitigated by master netting agreements and collateral support.

Outlook

We expect our capital structure will provide us financial flexibility to meet our requirements for working capital, capital expenditures and tax and debt payments while maintaining a sufficient level of liquidity. Our primary sources of liquidity in 2016 are expected cash flows from operations, proceeds from monetization of assets and, if necessary, borrowings on our $1.75 billion credit facility. We anticipate that the combination of these sources should be sufficient to allow us to pursue our business strategy and goals for 2016.

We note the following assumptions for 2016:

- our planned capital expenditures are estimated to be approximately $350 million to $450 million in 2016;
- anticipated proceeds totaling $1.2 billion (prior to closing adjustments) from asset sales in 2016;
- we target to reduce debt and we may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material; and
- we have hedged approximately three-fourths of our anticipated 2016 oil production at a weighted-average price of $60.85 per barrel. Excluding the derivatives anticipated to be assigned to the Piceance Basin buyer at closing, WPX has natural gas derivatives totaling 213,604 MMBtu per day for 2016, at a weighted price of $3.79 per MMBtu.

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;
- significantly lower than expected capital expenditures could result in the loss of undeveloped leasehold; and
- reduced access to our credit facility pursuant to our financial covenants.

Credit Facility

We have a $1.75 billion , five -year senior unsecured revolving credit facility agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the “Credit Facility”). The Credit Facility matures on October 28, 2019 . The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of December 31, 2015 , we were in compliance with our financial covenants, had full access to the Credit Facility and had outstanding borrowings of $265 million . From December 31, 2015 to February 25, 2016, we borrowed an additional $110 million on our revolving credit facility. From December 31, 2015 to February 25, 2016, we repurchased $51 million of long-term notes due in 2017 (see Note 16 of Notes to Consolidated Financial Statements for 2016 activity regarding our Credit Facility).

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

Under the amended Credit Facility, if the Company’s Corporate Rating is (a) BB- or worse by S&P and Ba3 or worse by Moody’s or (b) B+ or worse by S&P or B1 or worse by Moody’s, we will be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the Credit Facility, to Consolidated Indebtedness of at least 1.10 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and at least 1.50 to 1.00 thereafter unless and until (i) the Company’s Corporate Rating is (A) BBB- or better with S&P (without negative outlook or negative watch) or (B) Baa3 or better by Moody’s (without negative outlook or negative watch) and (ii) the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody’s. As of December 31, 2015 , our credit rating with S&P was BB, positive outlook and our credit rating with Moody's is Ba1, negative outlook. Subsequent to December 31, 2015 , our credit ratings were downgraded to BB-, negative outlook and B2, negative outlook with S&P and Moody's, respectively. As a result of the rating changes, our availability may be limited in future compliance periods at current covenant levels. In order to preserve liquidity, we are in discussions with our Administrative Agent and other lenders regarding amendments to our Credit Facility.

In addition, the amendment increased the ratio of Consolidated Net Indebtedness to Consolidated EBITDAX we are required to maintain to not greater than 4.50 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and 4.00 to 1.00 thereafter, unless at such time the Company’s Corporate Ratings are equal to, or better than, Baa3 or BBB- by at least one of S&P and Moody’s and not less than BB+ or Ba1 by the other such agency. Furthermore, the amendment added a financial covenant requiring us to not permit the ratio of Consolidated EBITDAX to Consolidated Interest Charges to be less than 2.50 to 1.00. See Note 16 of Notes to Consolidated Financial Statements for information regarding additional amendments to our Credit Facility in 2016.

We have three bilateral, uncommitted letter of credit agreements most of which expire throughout 2016. These agreements allow us to preserve our liquidity under our Credit Facility while providing support to our ability to meet performance obligation needs for, among other items, various interstate pipeline contracts into which we have entered. These unsecured agreements incorporate similar terms as those in the Credit Facility. At December 31, 2015 , a total of $233 million in letters of credit have been issued. If these letter of credit agreements are not renewed, we may issue letters of credit under our Credit Facility.

Credit Ratings

As previously noted, our ability to borrow money will be impacted by several factors, including our credit ratings. Credit ratings agencies perform independent analysis when assigning credit ratings. A downgrade of our current rating could increase our future cost of borrowing and result in a requirement that we post additional collateral with third parties, thereby negatively affecting our available liquidity. See Note 16 of Notes to Consolidated Financial Statements for information regarding changes in our credit ratings subsequent to February 25, 2016. The ratings as of February 25, 2016 were as follows:

Standard and Poor's(a)	
Corporate Credit Rating	BB-
Senior Unsecured Debt Rating	BB-
Outlook	Negative
Moody's Investors Service(b)	
LT Corporate Family Rating	B2
Senior Unsecured Debt Rating	B2
Outlook	Negative

(a) A rating of "BBB" or above indicates an investment grade rating. A rating below "BBB" indicates that the security has significant speculative characteristics. A "BB" rating indicates that Standard & Poor's believes the issuer has the capacity to meet its financial commitment on the obligation, but adverse business conditions could lead to insufficient ability to meet financial commitments. Standard & Poor's may modify its ratings with a "+" or a "-" sign to show the obligor's relative standing within a major rating category.

(b) A rating of "Baa" or above indicates an investment grade rating. A rating below "Baa" is considered to have speculative elements. The "1," "2," and "3" modifiers show the relative standing within a major category. A "1" indicates that an obligation ranks in the higher end of the broad rating category, "2" indicates a mid-range ranking, and "3" indicates the lower end of the category.

Sources (Uses) of Cash

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Net cash provided (used) by:			
Operating activities	$ 811	$ 1,070	$ 636
Investing activities	(1,316)	(1,437)	(1,111)
Financing activities	473	344	426
Increase (decrease) in cash and cash equivalents	$ (32)	$ (23)	$ (49)

Operating activities

Excluding changes in working capital, total cash provided by operating activities related to discontinued operations was approximately $ 187 million , $650 million and $ 534 million for 2015 , 2014 and 2013 , respectively. Total cash provided by operating activities related to continuing operations decreased due to a decrease in commodity prices and natural gas volumes, substantially offset by cash received on settlement of derivative contracts and higher oil volumes. Total cash provided by operating activities for 2015 also includes approximately $23 million of acquisition costs related to the Acquisition.

Our net cash provided by operating activities in 2014 increased from 2013 primarily due to higher operating results driven by higher average natural gas prices and increased oil production volumes. In addition, 2014 increased due to higher net gas management revenues and expenses as previously discussed.

Investing activities

During 2015, we successfully closed the purchase of RKI and paid approximately $1.2 billion in cash, net of cash acquired.

Cash capital expenditures for drilling and completions were $1.0 billion, $1.4 billion and $1.0 billion in 2015, 2014 and 2013, respectively. Cash capital expenditures for drilling and completion related to our domestic discontinued operations were $234 million, $479 million, and $339 million in 2015, 2014 and 2013, respectively. Capital expenditures incurred for drilling and completions totaled $733 million, $1.5 billion and $1.0 billion in 2015, 2014 and 2013, respectively. Capital expenditures incurred for drilling and completions related to our domestic discontinued operations were $170 million, $495 million, and $350 million in 2015, 2014 and 2013, respectively. Domestic land acquisitions were $59 million, $297 million and $61 million during 2015, 2014 and 2013, respectively. Included in land acquisitions for 2014 was approximately $150 million related to the purchase of oil and natural gas properties in the San Juan Basin (see Note 6 of Notes to Consolidated Financial Statements). In addition, capital expenditures for international discontinued operations were $15 million, $85 million and $51 million during 2015, 2014 and 2013, respectively.

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

2015

- $291 million after expenses but before $17 million of cash on hand at Apco as of the closing date, for the divestiture of our 69 percent controlling equity interest in Apco and additional Argentina-related assets to Pluspetrol (see Note 3 of Notes to Consolidated Financial Statements).
- $271 million for the sale of a portion of our Appalachian Basin operations and release of certain firm transportation capacity to Southwestern Energy Company during the first quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).
- $209 million for the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast during May 2015 (see Note 5 of Notes to Consolidated Financial Statements).
- $182 million for the sale of a North Dakota gathering system that closed during the fourth quarter of 2015 (see Note 5 of Notes to Consolidated Financial Statements).
- $67 million for the sale of our Powder River Basin assets during fourth quarter of 2015 (see Note 3 of Notes to Consolidated Financial Statements).

2014

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

2013

- We received proceeds of $36 million from the sale of deep rights leasehold in the Powder River Basin.

Financing activities

During 2015, we completed equity offerings of (a) 30 million shares of our common stock for net proceeds of approximately $ 292 million and (b) $350 million of aggregate liquidation preference of 6.25% series A mandatory convertible preferred stock for net proceeds of approximately $339 million (see Note 13 of Notes to Consolidated Financial Statements).

Also, during 2015, we completed a debt offering of (a) $500 million aggregate principal amount of 7.500% senior unsecured notes due 2020 and (b) $500 million aggregate principal amount of 8.250% senior unsecured notes due 2023 (see Note 8 of Notes to Consolidated Financial Statements).

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

Net cash provided by financing activities for 2015 was also impacted by net payments under the Credit Facility of $ 15 million . In August 2015, we utilized borrowings under the Credit Facility for the Acquisition. Net cash provided by financing activities in 2014 includes $130 million of net payments on our Credit Facility. Net cash provided by financing activities in 2013 includes $410 million net borrowings on our credit facility.

During 2015 , we repurchased approximately $45 million of our 2017 Notes. We also made $ 40 million in payments for debt issuance costs and acquisition bridge financing fees for the debt offerings and revolver amendments.

During 2014 , we issued $500 million of senior unsecured notes at an interest rate of 5.250% . We used the proceeds from this offering to repay borrowings under our revolving credit facility and for related transaction fees and expenses (see Note 8 of Notes to Consolidated Financial Statements).

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 December 31, 2015 and December 31, 2014 .

Contractual Obligations

The table below summarizes the maturity dates of our contractual obligations at December 31, 2015 .

	2016	2017 – 2018	2019 – 2020	Thereafter	Total
			(Millions)		
Long-term debt, including current portion:					
Principal	$ 1	$ 355	$ 765	$ 2,100	$ 3,221
Interest	195	363	347	328	1,233
Operating leases and associated service commitments:					
Drilling rig commitments(a)	36	23	—	—	59
Other	18	21	14	9	62
Transportation and storage commitments(b)	140	246	195	105	686
Oil and gas activities(c)	122	220	119	119	580
Other	11	10	4	—	25
Other long-term liabilities, including current portion:					
Physical and financial derivatives(d)	19	2	—	—	21
Total obligations	$ 542	$ 1,240	$ 1,444	$ 2,661	$ 5,887

(a) Includes materials and services obligations associated with our drilling rig contracts.

(b) Includes firm demand obligations of $139 million for which $113 million is recorded as a liability as of December 31, 2015. The liability was recorded in conjunction with our exit from the Powder River Basin (see Note 3 of Notes to Consolidated Financial Statements). Also included is approximately $104 million of which the purchaser of our Piceance Basin operations will become financially responsible (see Note 3 of Notes to Consolidated Financial Statements). See Note 16 of Notes to Consolidated Financial Statements for a discussion of an agreement signed in May 2016 related to a portion of the remaining transportation obligations.

(c) Includes gathering, processing and other oil and gas related services commitments of which $92 million and $33 million associated with our exit from the Powder River Basin and sale of a portion of our Appalachian Basin operations respectively, of which we have recorded $82 million as a liability as of December 31, 2015 (see Notes 3 and 5 of Notes to Consolidated Financial Statements). In addition, approximately $106 million is associated with our Piceance Basin operations, which will be assumed by the purchaser (see Note 3 of Notes to Consolidated Financial Statements). Excluded are liabilities associated with asset retirement obligations totaling $236 million as of December 31, 2015, of which $133 million relates to our Piceance Basin assets and obligations of approximately $371 million associated with gathering services to be provided to us by the purchaser of our San Juan Basin gathering system after closing (see Note 5 of Notes to Consolidated Financial Statements). The ultimate settlement and timing of asset retirement obligations cannot be precisely determined in advance; however, we estimate that approximately 13 percent of this liability, excluding the portion associated with our Piceance Basin assets, will be settled in the next five years.

(d) Includes approximately $8 million of physical natural gas derivatives related to purchases at market prices. The natural gas expected to be purchased under these contracts can be sold at market prices, largely offsetting this obligation. The obligations for physical and financial derivatives are based on market information as of December 31, 2015 , and assume contracts remain outstanding for their full contractual duration. Because market information changes daily and is subject to volatility, significant changes to the values in this category may occur.

Effects of Inflation

Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy. Operating costs are influenced by both competition for specialized services and specific price changes in oil, natural gas, NGLs and other commodities. We tend to experience inflationary pressure on the cost of services and equipment when higher oil and gas prices cause an increase in drilling activity in our areas of operation. Likewise, lower prices and reduced drilling activity may lower the costs of services and equipment.

Environmental

Our operations are subject to governmental laws and regulations relating to the protection of the environment, and increasingly strict laws, regulations and enforcement policies, as well as future additional environmental requirements, could materially increase our costs of operation, compliance and any remediation that may become necessary.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and the disclosure of contingent assets and liabilities. We believe that the nature of these estimates and assumptions is material due to the subjectivity and judgment necessary, the susceptibility of such matters to change, and the impact of these on our financial condition or results of operations.

In our management's opinion, the more significant reporting areas impacted by management's judgments and estimates are as follows:

Impairments of Long-Lived Assets

We evaluate our long-lived assets for impairment when we believe events or changes in circumstances indicate that we may not be able to recover the carrying value. Our computations utilize judgments and assumptions that include estimates of the undiscounted future cash flows, discounted future cash flows, estimated fair value of the asset, and the current and future economic environment in which the asset is operated.

Due to market conditions including oil and natural gas prices in the fourth quarter of 2015, we assessed our proved properties for impairment using estimates of future cash flows. Significant judgments and assumptions are inherent in these assessments and include estimates of reserves quantities, estimates of future commodity prices (developed in consideration of market information, internal forecasts and published forward prices adjusted for locational basis differentials), drilling plans, expected capital and lease operating costs and our estimate of an applicable discount rate commensurate with the risk of the underlying cash flow estimates. Additionally, judgment is used to determine the probability of sale and expected proceeds with respect to assets considered for disposal. The assessment performed identified certain properties with a carrying value in excess of those estimated undiscounted cash flows and their calculated fair values. As a result of these assessments which included the possibility of divestiture, we recognized approximately $2.3 billion of impairment charges on proved and unproved properties in the Piceance Basin in 2015. See Notes 3 and 14 of Notes to Consolidated Financial Statements for additional discussion and significant inputs into the fair value determination.

In addition to those long-lived assets described above for which impairment charges were recorded, certain others were reviewed for which no impairment was required at the time. These reviews included $3.9 billion of net book value associated with our predominantly oil proved properties and $350 million of net book value associated with our predominantly natural gas proved properties excluding the Piceance properties discussed above, and utilized inputs generally consistent with those described above. Many judgments and assumptions are inherent and to some extent interdependent of one another in our estimate of future cash flows used to evaluate these assets. The use of alternate judgments and assumptions could result in the recognition of different levels of impairment charges in the consolidated financial statements. If the estimated commodity revenues (only one of the many estimates involved) of the predominately oil proved properties reviewed but for which impairment charges were not recorded were lower by 15 to 20 percent, these properties could be at risk for impairment. Over 68 percent of our future production considered in the impairment assessment is in years 2021 and beyond.

Successful Efforts Method of Accounting for Oil and Gas Exploration and Production Activities

We use the successful efforts method of accounting for our oil- and gas-producing activities. Estimated natural gas and oil reserves and forward market prices for oil and gas are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- an increase (decrease) in estimated proved oil, natural gas and NGL reserves can reduce (increase) our unit-of-production depreciation, depletion and amortization rates; and
- changes in oil, natural gas, and NGL reserves and forward market prices both impact projected future cash flows from our properties. This, in turn, can impact our periodic impairment analyses.

The process of estimating oil and natural gas reserves is very complex, requiring significant judgment in the evaluation of all available geological, geophysical, engineering and economic data. After being estimated internally, approximately 99 percent of our domestic reserves estimates are audited by independent experts. The data may change substantially over time as a result of numerous factors, including the historical 12 month weighted average price, additional development cost and activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserves estimates could occur from time to time. Such changes could trigger an impairment of our oil and gas properties and have an impact on our depreciation, depletion and amortization expense prospectively. For example, a change of approximately 10 percent in our total oil and gas reserves could change our annual depreciation, depletion and amortization expense between approximately $46 million and $57 million. The actual impact would depend on the specific basins impacted and whether the change resulted from proved developed, proved undeveloped or a combination of these reserves categories.

Estimates of future commodity prices, which are utilized in our impairment analyses, consider market information including published forward oil and natural gas prices. The forecasted price information used in our impairment analyses is consistent with that generally used in evaluating our drilling decisions and acquisition plans. Prices for future periods impact the production economics underlying oil and gas reserve estimates. In addition, changes in the price of natural gas and oil also impact certain costs associated with our underlying production and future capital costs. The prices of oil and natural gas are volatile and change from period to period, thus impacting our estimates. Significant unfavorable changes in the estimated future commodity prices could result in an impairment of our oil and gas properties.

We record the cost of leasehold acquisitions as incurred. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. Changes in our assumptions regarding the estimates of the nonproductive portion of these leasehold acquisitions could result in impairment of these costs. Upon determination that specific acreage will not be developed, the costs associated with that acreage would be impaired. Additionally, our leasehold costs are evaluated for impairment if the proved property costs in the basin are impaired. Our capitalized lease acquisition costs totaled $2.3 billion at December 31, 2015 and is primarily associated with our Permian Basin acreage.

Purchase Accounting

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

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

In many cases, estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and loss carryovers at the acquisition date, although such estimates may change in the future as additional information becomes known.

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

Fair Value Measurements

A limited amount of our energy derivative assets and liabilities trade in markets with lower availability of pricing information requiring us to use unobservable inputs and are considered Level 3 in the fair value hierarchy. For Level 2 transactions, we do not make significant adjustments to observable prices in measuring fair value as we do not generally trade in inactive markets.

The determination of fair value for our energy derivative 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 energy derivative liabilities. The determination of the fair value of our energy derivative liabilities does not consider noncash collateral credit enhancements. For net derivative assets, we apply a credit spread, based on the credit rating of the counterparty, against the net derivative asset with that counterparty. For net derivative liabilities, we apply our own credit rating. We derive the credit spreads by using the corporate industrial credit curves for each rating category and building a curve based on certain points in time for each rating category. The spread comes from the discount factor of the individual corporate curves versus the discount factor of the LIBOR curve. At December 31, 2015 , the credit reserve is $1 million on our net derivative assets and net derivative liabilities. Considering these factors and that we do not have significant risk from our net credit exposure to derivative counterparties, the impact of credit risk is not significant to the overall fair value of our derivatives portfolio.

At December 31, 2015 , 86 percent of the fair value of our derivatives portfolio expires in the next 12 months and more than 99 percent expires in the next 24 months. Our derivatives portfolio is largely comprised of exchange-traded products or like products where price transparency has not historically been a concern. Due to the nature of the markets in which we transact and the relatively short tenure of our derivatives portfolio, we do not believe it is necessary to make an adjustment for illiquidity. We regularly analyze the liquidity of the markets based on the prevalence of broker pricing and exchange pricing for products in our derivatives portfolio.

The instruments included in Level 3 at December 31, 2015 , consist of natural gas index transactions that are used to manage the physical requirements of our business. The change in the overall fair value of instruments included in Level 3 primarily results from changes in commodity prices during the month of delivery. There are generally no active forward markets or quoted prices for natural gas index transactions.

For the years ended December 31, 2015 , 2014 and 2013 , we recognized impairments of certain assets that were measured at fair value on a nonrecurring basis. These impairment measurements are included in Level 3 as they include significant unobservable inputs, such as our estimate of future cash flows and the probabilities of alternative scenarios. See Note 14 of Notes to Consolidated Financial Statements.

Contingent Liabilities

We record liabilities for estimated loss contingencies, including royalty litigation, environmental and other contingent matters, when we assess that a loss is probable and the amount of the loss can be reasonably estimated. Revisions to contingent liabilities are generally reflected in income when new or different facts or information become known or circumstances change that affect the previous assumptions with respect to the likelihood or amount of loss. Liabilities for contingent losses are based upon our assumptions and estimates and upon advice of legal counsel, engineers or other third parties regarding the probable outcomes of the matter. As new developments occur or more information becomes available, our assumptions and estimates of these liabilities may change. Changes in our assumptions and estimates or outcomes different from our current assumptions and estimates could materially affect future results of operations for any particular quarterly or annual period. See Note 10 of Notes to Consolidated Financial Statements.

Valuation of Deferred Tax Assets and Liabilities

We record deferred taxes for the differences between the tax and book basis of our assets as well as loss or credit carryovers to future years. Included in our deferred taxes are deferred tax assets resulting from certain investments and businesses that have a tax basis in excess of book basis, certain federal and state tax loss carryovers generated in the current and prior years, and alternative minimum tax credits. We must periodically evaluate whether it is more likely than not we will realize these deferred tax assets and establish a valuation allowance for those that do not meet the more likely than not threshold. When assessing the need for a valuation allowance, we primarily consider future reversals of existing taxable temporary differences. To a lesser extent, we also consider future taxable income exclusive of reversing temporary differences and carryovers, and tax-planning strategies that would, if necessary, be implemented to accelerate taxable amounts to utilize expiring carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by future operational performance, potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets.

The determination of our state deferred tax requires judgment as our effective state deferred tax rate can change periodically based on changes in our operations. Our effective state deferred tax rate is based upon our current entity structure and the jurisdictions in which we operate.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest Rate Risk

Our interest rate risk exposure is related primarily to our debt portfolio. Our senior notes are fixed rate debt in order to mitigate the impact of fluctuations in interest rates. For our fixed rate debt, $355 million matures in 2017, $500 million matures in 2020, $1,100 million matures in 2022, $500 million matures in 2023 and $500 million matures in 2024. Interest rates for each group are 5.25 percent, 7.50 percent, 6.00 percent, 8.25 percent and 5.25 percent, respectively. The aggregate fair value of the senior notes is $2,230 million. Borrowings under our credit facility are based on a variable interest rate and could expose us to the risk of increasing interest rates. As of December 31, 2015 , the weighted average variable interest rate was 2.20 percent on the $265 million outstanding under the Credit Facility Agreement. See Note 8 of Notes to Consolidated Financial Statements.

Commodity Price Risk

We are exposed to the impact of fluctuations in the market price of oil, natural gas and NGLs, 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 14 and 15 of Notes to Consolidated Financial Statements.

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

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

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

Trading

Our trading portfolio consists of derivative contracts entered into for purposes other than economically hedging our commodity price-risk exposure. The fair value of our trading derivatives was zero at December 31, 2015 and a net asset of $1 million at December 31, 2014 . The value at risk for contracts held for trading purposes was zero at December 31, 2015 and less than $1 million at December 31, 2014 .

Nontrading

Our nontrading portfolio consists of derivative contracts that hedge or could potentially hedge the price risk exposure from our energy commodity purchases and sales. The fair value of our derivatives not designated as hedging instruments was a net asset of $344 million and $479 million at December 31, 2015 and December 31, 2014 , respectively.

The value at risk for derivative contracts held for nontrading purposes was $19 million at December 31, 2015 , and $16 million at December 31, 2014 . During the year ended December 31, 2015 , our value at risk for these contracts ranged from a high of $23 million to a low of $16 million. The increase in value at risk from December 31, 2014 primarily reflects decreases in market prices on contracts entered into to economically hedge our equity production.

Item 8. ***Financial Statements and Supplementary Data***

Below is Management's Annual Report on Internal Control Over Financial Reporting as of February 25, 2016 as reported in our Annual Report on Form 10-K for the year ended December 31, 2015.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a—15(f) and 15d—15(f) under the Securities Exchange Act of 1934). Our internal controls over financial reporting are designed to provide reasonable assurance to our management and Board of Directors regarding the preparation and fair presentation of financial statements in accordance with accounting principles generally accepted in the United States. Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets; (ii) provide reasonable assurance that transactions are recorded as to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorization of our management and Board of Directors; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

All internal control systems, no matter how well designed, have inherent limitations including the possibility of human error and the circumvention or overriding of controls. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of December 31, 2015, based on the criteria set forth in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on our assessment, we concluded that, as of December 31, 2015, our internal control over financial reporting was effective.

On August 17, 2015, we completed our acquisition of RKI. We are analyzing RKI's internal controls over financial reporting and are integrating them within our framework of controls. As a result, for the period ended December 31, 2015, we excluded RKI from our assessment of internal controls over financial reporting; however, we plan to complete the process of integrating RKI into our control framework no later than the first anniversary of the Acquisition, as required by the SEC. RKI's total assets and total revenues represent 39 percent and 3 percent, respectively, of the related consolidated financial statement amounts as of and for the period ended December 31, 2015 as filed in our Annual Report on Form 10-K.

Ernst & Young LLP, our independent registered public accounting firm, has audited our internal control over financial reporting, as stated in their report which is included in this Current Report on Form 8-K.

Report of Independent Registered Public Accounting Firm on
Internal Control over Financial Reporting

The Board of Directors and Shareholders of WPX Energy, Inc.,

We have audited WPX Energy, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). WPX Energy Inc.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As indicated in the accompanying Management's Annual Report On Internal Control Over Financial Reporting, management's assessment of and conclusion on the effectiveness of internal control over financial reporting did not include the internal controls of RKI Exploration & Production, LLC, which is included in the 2015 consolidated financial statements of WPX Energy, Inc. and constituted 39 percent and 69 percent of total assets and net assets, respectively, as of December 31, 2015 and 3 percent and 3 percent of revenues and net loss, respectively, for the year then ended. Our audit of internal control over financial reporting of WPX Energy, Inc. also did not include an evaluation of the internal control over financial reporting of RKI Exploration & Production, LLC.

In our opinion, WPX Energy, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of WPX Energy Inc. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2015 of WPX Energy, Inc. and our report dated February 25, 2016, except for the effects of discontinued operations as discussed in Note 3 and Note 16, as to which the date is May 25, 2016, expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of WPX Energy, Inc.,

We have audited the accompanying consolidated balance sheets of WPX Energy, Inc. as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income (loss), changes in equity and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in Exhibit 99.2. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of WPX Energy, Inc. at December 31, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), WPX Energy, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 25, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Tulsa, Oklahoma
February 25, 2016, except for the effects of discontinued operations as discussed in Note 3 and Note 16, as to which the date is May 25, 2016 .

WPX Energy, Inc.
Consolidated Balance Sheets

	December 31,	
	2015	2014
	(Millions)	
Assets		
Current assets:		
Cash and cash equivalents	$ 38	$ 41
Accounts receivable, net of allowance of $6 million as of December 31, 2015 and December 31, 2014	300	437
Derivative assets	308	498
Inventories	46	31
Margin deposits	1	27
Assets classified as held for sale	178	930
Other	22	23
Total current assets	893	1,987
Properties and equipment, net (successful efforts method of accounting)	6,522	3,395
Derivative assets	51	24
Assets classified as held for sale	894	3,464
Other noncurrent assets	33	26
Total assets	$ 8,393	$ 8,896
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 278	$ 638
Accrued and other current liabilities	302	145
Liabilities associated with assets held for sale	140	357
Deferred income taxes (Note 1)	—	151
Derivative liabilities	13	37
Total current liabilities	733	1,328
Deferred income taxes	465	621
Long-term debt, net	3,189	2,260
Derivative liabilities	2	5
Asset retirement obligations	99	75
Liabilities associated with assets held for sale	133	151
Other noncurrent liabilities	237	28
Contingent liabilities and commitments (Note 10)		
Equity:		
Stockholders' equity:		
Preferred stock (100 million shares authorized at $0.01 par value; 7 million shares issued at December 31, 2015)	339	—
Common stock (2 billion shares authorized at $0.01 par value; 275.4 million shares issued at December 31, 2015 and 203.7 million shares issued at December 31, 2014)	3	2
Additional paid-in-capital	6,164	5,562
Accumulated deficit	(2,971)	(1,244)
Accumulated other comprehensive income (loss)	—	(1)
Total stockholders' equity	3,535	4,319
Noncontrolling interests in consolidated subsidiaries	—	109
Total equity	3,535	4,428
Total liabilities and equity	$ 8,393	$ 8,896

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Operations

	Years Ended December 31,		
	2015	2014	2013
Revenues:	(Millions, except per share amounts)		
Product revenues:			
Oil sales	$ 494	$ 669	$ 475
Natural gas sales	138	282	259
Natural gas liquid sales	23	20	10
Total product revenues	655	971	744
Gas management	286	1,110	882
Net gain (loss) on derivatives not designated as hedges (Note 15)	418	434	(124)
Other	7	8	3
Total revenues	1,366	2,523	1,505
Costs and expenses:			
Lease and facility operating	145	143	109
Gathering, processing and transportation	64	71	73
Taxes other than income	62	88	68
Gas management, including charges for unutilized pipeline capacity (Note 5)	261	979	927
Exploration (Note 5)	85	101	417
Depreciation, depletion and amortization	528	363	354
Impairment of producing properties and costs of acquired unproved reserves (Note 5)	—	15	772
Net (gain) loss on sales of assets (Note 5)	(349)	—	—
General and administrative	210	224	218
Acquisition costs (Note 2)	23	—	—
Other—net	63	13	12
Total costs and expenses	1,092	1,997	2,950
Operating income (loss)	274	526	(1,445)
Interest expense (Note 2)	(187)	(123)	(108)
Loss on extinguishment of acquired debt (Note 2)	(65)	—	—
Investment income, impairment of equity method investment and other	(2)	1	(19)
Income (loss) from continuing operations before income taxes	20	404	(1,572)
Provision (benefit) for income taxes	24	148	(567)
Income (loss) from continuing operations	(4)	256	(1,005)
Income (loss) from discontinued operations	(1,722)	(85)	(186)
Net income (loss)	(1,726)	171	(1,191)
Less: Net income (loss) attributable to noncontrolling interests	1	7	(6)
Net income (loss) attributable to WPX Energy, Inc.	$ (1,727)	$ 164	$ (1,185)
Less: Dividends on preferred stock	9	—	—
Net income (loss) attributable to WPX Energy, Inc. common stockholders	$ (1,736)	$ 164	$ (1,185)

(continued on next page)

WPX Energy, Inc.

Consolidated Statements of Operations—(Continued)

	Years Ended December 31,		
	2015	2014	2013
	(Millions, except per share amounts)		
Amounts attributable to WPX Energy, Inc. common stockholders:			
Income (loss) from continuing operations	$ (13)	$ 256	$ (993)
Income (loss) from discontinued operations	(1,723)	(92)	(192)
Net income (loss)	$ (1,736)	$ 164	$ (1,185)
Basic earnings (loss) per common share (Note 4):			
Income (loss) from continuing operations	$ (0.06)	$ 1.26	$ (4.95)
Income (loss) from discontinued operations	(7.36)	(0.45)	(0.96)
Net income (loss)	$ (7.42)	$ 0.81	$ (5.91)
Basic weighted-average shares	234.2	202.7	200.5
Diluted earnings (loss) per common share (Note 4):			
Income (loss) from continuing operations	$ (0.06)	$ 1.24	$ (4.95)
Income (loss) from discontinued operations	(7.36)	(0.44)	(0.96)
Net income (loss)	$ (7.42)	$ 0.80	$ (5.91)
Diluted weighted-average shares	234.2	206.3	200.5

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Comprehensive Income (Loss)

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Net income (loss) attributable to WPX Energy, Inc.	$ (1,727)	$ 164	$ (1,185)
Less: Dividends on preferred stock	9	—	—
Net income (loss) attributable to WPX Energy, Inc. common stockholders	$ (1,736)	$ 164	$ (1,185)
Other comprehensive income (loss):			
Net reclassifications into earnings of net cash flow hedge gains, net of tax(a)	—	—	(3)
Other comprehensive income (loss), net of tax	—	—	(3)
Comprehensive income (loss) attributable to WPX Energy, Inc. common stockholders	$ (1,736)	$ 164	$ (1,188)

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

See accompanying notes.

WPX Energy, Inc.
Consolidated Statements of Changes in Equity

	WPX Energy, Inc., Stockholders							
	Preferred Stock	Common Stock	Capital in Excess of Par Value	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total Stockholders' Equity	Noncontrolling Interests(a)	Total
	(Millions)							
Balance at December 31, 2012	$ —	$ 2	$ 5,487	$ (223)	$ 2	$ 5,268	$ 103	$ 5,371
Comprehensive income:								
Net income (loss)	—	—	—	(1,185)	—	(1,185)	(6)	(1,191)
Other comprehensive income (loss)		—	—		(3)	(3)	—	(3)
Comprehensive income (loss)								(1,194)
Contribution from noncontrolling interest							4	4
Stock based compensation, net of tax benefit	—		29			29		29
Balance at December 31, 2013	—	2	5,516	(1,408)	(1)	4,109	101	4,210
Comprehensive income:								
Net income (loss)	—	—	—	164	—	164	7	171
Other comprehensive income (loss)		—	—		—	—	—	—
Comprehensive income (loss)								171
Contribution from noncontrolling interest							1	1
Stock based compensation, net of tax benefit	—	—	46		—	46	—	46
Balance at December 31, 2014	—	2	5,562	(1,244)	(1)	4,319	109	4,428
Comprehensive income:								
Net income (loss)	—	—	—	(1,727)		(1,727)	1	(1,726)
Comprehensive income (loss)								(1,726)
Stock based compensation, net of tax benefit	—	—	26		—	26	—	26
Dividends on preferred stock			(11)			(11)	—	(11)
Issuance of common stock to public, net of offering costs			292			292	—	292
Issuance of common stock related to an acquisition		1	295			296	—	296
Issuance of preferred stock to public, net of offering costs	339					339	—	339
Impact of divestitures					1	1	(110)	(109)
Balance at December 31, 2015	$ 339	$ 3	$ 6,164	$ (2,971)	$ —	$ 3,535	$ —	$ 3,535

(a) Primarily represents the 31 percent of Apco Oil and Gas International Inc. owned by others.

See accompanying notes.

WPX Energy, Inc.

Consolidated Statements of Cash Flows

	Years Ended December 31,		
	2015	2014	2013
Operating Activities		(Millions)	
Net income (loss)	$ (1,726)	$ 171	$ (1,191)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	940	863	940
Deferred income tax provision (benefit)	(1,005)	46	(645)
Provision for impairment of properties and equipment (including certain exploration expenses) and investments	2,426	236	1,483
Amortization of stock-based awards	35	36	32
Loss on extinguishment of acquired debt and acquisition bridge financing fees	81	—	—
(Gain) loss on sales of domestic assets and international interests	(385)	196	(41)
Cash provided (used) by operating assets and liabilities:			
Accounts receivable	233	51	(43)
Inventories	(2)	19	(5)
Margin deposits and customer margin deposits payable	26	(10)	(18)
Other current assets	—	8	(7)
Accounts payable	(247)	4	41
Accrued and other current liabilities	79	(1)	(21)
Changes in current and noncurrent derivative assets and liabilities	199	(559)	106
Other, including changes in other noncurrent assets and liabilities	157	10	5
Net cash provided by operating activities(a)	811	1,070	636
Investing Activities			
Capital expenditures(b)	(1,124)	(1,807)	(1,154)
Proceeds from sales of domestic assets and international interests	1,019	374	49
Purchases of a business, net of cash acquired	(1,212)	—	—
Other	1	(4)	(6)
Net cash used in investing activities(a)	(1,316)	(1,437)	(1,111)
Financing Activities			
Proceeds from common stock	295	16	6
Proceeds from preferred stock	339	—	—
Dividends paid on preferred stock	(6)	—	—
Proceeds from long-term debt	1,000	500	—
Payments for retirement of long-term debt	(45)	—	—
Payments for retirement of acquired debt	(1,055)	—	—
Borrowings on credit facility	841	1,947	970
Payments on credit facility	(856)	(2,077)	(560)
Payments for debt issuance costs and acquisition bridge financing fees	(40)	(13)	—
Other	—	(29)	10
Net cash provided by financing activities	473	344	426
Net increase (decrease) in cash and cash equivalents	(32)	(23)	(49)
Effect of exchange rate changes on international cash and cash equivalents	—	(6)	(5)
Cash and cash equivalents at beginning of period(c)	70	99	153
Cash and cash equivalents at end of period(c)	$ 38	$ 70	$ 99

(a) Amounts include activity related to discontinued operations. See Note 3 of Notes to Consolidated Financial Statements for discussion of discontinued operations.

(b) Increase to properties and equipment	$ (865)	$ (1,934)	$ (1,207)
Changes in related accounts payable and accounts receivable	(259)	127	53
Capital expenditures	$ (1,124)	$ (1,807)	$ (1,154)

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

See accompanying notes.

Note 1 . Description of Business, Basis of Presentation, and Summary of Significant Accounting Policies

Description of Business

Operations of our company include oil, natural gas and NGL development, production and gas management activities primarily located in Texas, North Dakota, New Mexico and Colorado in the United States. We specialize in development and production from tight-sands and shale formations in the Williston and San Juan Basins and we have recently entered the core of the Permian's Delaware Basin through our acquisition of RKI Exploration & Production, LLC ("RKI"). See Note 2 for additional information regarding this acquisition. We also have operations and interests in the Appalachian and Green River Basins located in Pennsylvania and Wyoming. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation and related derivatives, coupled with the sale of our commodity volumes.

In addition, we had operations in the Piceance Basin in Colorado, which were sold April 8, 2016. We also had operations for a portion of 2015 in the Powder River Basin in Wyoming, which were sold on September 1, 2015 and, until January 29, 2015, we had a 69 percent controlling interest in Apco Oil and Gas International Inc. ("Apco"), an oil and gas exploration and production company with activities in Argentina and Colombia. For all periods presented, the results of the Piceance Basin, Powder River Basin and Apco are reported as discontinued operations.

The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as "WPX" or the "Company," is at times referred to in the first person as "we," "us" or "our."

Basis of Presentation

These financial statements are prepared on a consolidated basis.

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

Discontinued operations

On February 8, 2016, we signed an agreement to sell our Piceance Basin operations to Terra Energy Partners LLC ("Terra") for $910 million . This transaction closed on April 8, 2016. The assets and liabilities have been reclassified as held for sale on the Consolidated Balance Sheets and the results of operations of the Piceance Basin have been reclassified as discontinued operations on the Consolidated Statements of Operations (see Note 3).

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

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

See Note 3 for a further discussion of discontinued operations. Unless indicated otherwise, the information in the Notes to Consolidated Financial Statements relates to continuing operations. Additionally, see Note 10 for a discussion of contingencies related to Williams' former power business (most of which was disposed of in 2007).

Recently Adopted Accounting Standards

In April 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-03, *Simplifying the Presentation of Debt Issuance Costs* . The core principles of the guidance in ASU 2015-03 require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by the guidance in this update. In August 2015, the FASB issued ASU 2015-15 to incorporate into the ASU an SEC announcement that the SEC staff will not object to an entity presenting the cost of securing a line of credit as an asset. The Company has adopted ASU 2015-03 and ASU 2015-15 as of December 31, 2015 , and has applied its provisions retrospectively. The adoption of this standard resulted in the reclassification of $31 million and $20 million of unamortized debt issuance costs related to the Company's senior unsecured notes from other noncurrent assets to long-term debt within its Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014 , respectively. The unamortized costs associated with our revolving line of credit remain in other noncurrent assets for the periods presented. Other than this reclassification, the adoption of this standard did not have an impact on the Company's consolidated financial statements.

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

In November 2015, the FASB issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes* as part of the Simplification Initiative. To simplify the presentation of deferred income taxes, the amendments in this update require that deferred tax liabilities and assets be classified as noncurrent in a classified statement of financial position. ASU 2015-17 is effective for financial statements issued for annual reporting periods beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted as of the beginning of an interim or annual reporting period. The Company has adopted ASU 2015-17 prospectively beginning with the interim period October 1, 2015, thus prior periods were not retrospectively adjusted.

Accounting Standards Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09 and has updated with additional ASUs, *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, as amended, is effective for annual reporting periods beginning after December 15, 2017, including interim periods 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.

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

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

Summary of Significant Accounting Policies

Principles of consolidation

The consolidated financial statements include the accounts of our wholly and majority-owned subsidiaries and investments. Companies in which we own 20 percent to 50 percent of the voting common stock, or otherwise exercise significant influence over operating and financial policies of the Company, are accounted for under the equity method. All material intercompany transactions have been eliminated.

Use of estimates

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.

Significant estimates and assumptions which impact these financials include:

- impairment assessments of long-lived assets;
- valuations of derivatives;
- estimation of oil and natural gas reserves;
- assessments of litigation-related contingencies;
- asset retirement obligations; and
- valuation of deferred tax assets.

These estimates are discussed further throughout these notes.

Cash and cash equivalents

Our cash and cash equivalents balance includes amounts primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government. These have maturity dates of three months or less when acquired.

Restricted cash

Restricted cash consists of approximately $10 million and $6 million at December 31, 2015 and 2014 , respectively, and is included in other current assets on the Consolidated Balance Sheets.

Accounts receivable

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

Inventories

All inventories are stated at the lower of cost or market. Our materials, supplies and other inventories consist of tubular goods and production equipment for future transfer to wells and crude oil production in transit. Inventory is recorded and relieved using the weighted average cost method. The following table presents a summary of inventories.

	Years ended December 31,	
	2015	2014
	(Millions)	
Material, supplies and other	$ 44	$ 29
Crude oil production in transit	2	2
	$ 46	$ 31

Properties and equipment

Oil and gas exploration and production activities are accounted for under the successful efforts method. Costs incurred in connection with the drilling and equipping of exploratory wells are capitalized as incurred. If proved reserves are not found, such costs are charged to exploration expenses. Other exploration costs, including geological and geophysical costs and lease rentals are charged to expense as incurred. All costs related to development wells, including related production equipment and lease acquisition costs, are capitalized when incurred whether productive or nonproductive.

Unproved properties include lease acquisition costs and costs of acquired unproved reserves. Individually significant lease acquisition costs are assessed annually, or as conditions warrant, for impairment considering our future drilling plans, the remaining lease term and recent drilling results. Lease acquisition costs that are not individually significant are aggregated by prospect or geographically, and the portion of such costs estimated to be nonproductive prior to lease expiration is amortized over the average holding period. The estimate of what could be nonproductive is based on our historical experience or other information, including current drilling plans and existing geological data. Impairment and amortization of lease acquisition costs are included in exploration expense in the Consolidated Statements of Operations. A majority of the costs of acquired unproved reserves related to our discontinued operations and are associated with areas to which we or other producers have identified significant proved developed producing reserves. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing development program. Ultimate recovery of unproved reserves in areas with established production generally has greater probability than in areas with limited or no prior drilling activity. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. We refer to unproved lease acquisition costs and costs of acquired unproved reserves as unproved properties.

Gains or losses from the ordinary sale or retirement of properties and equipment are recorded in operating income (loss) as either a separate line item, if individually significant, or included in other—net on the Consolidated Statements of Operations.

Costs related to the construction or acquisition of field gathering, processing and certain other facilities are recorded at cost. Ordinary maintenance and repair costs are expensed as incurred.

Depreciation, depletion and amortization

Capitalized exploratory and developmental drilling costs, including lease and well equipment and intangible development costs are depreciated and amortized using the units-of-production method based on estimated proved developed oil and gas reserves on a field basis. Depletion of producing leasehold costs is based on the units-of-production method using estimated total proved oil and gas reserves on a field basis. In arriving at rates under the units-of-production methodology, the quantities of proved oil and gas reserves are established based on estimates made by our geologists and engineers.

Costs related to gathering, processing and certain other facilities are depreciated on the straight-line method over the estimated useful lives.

Impairment of long-lived assets

We evaluate our long-lived assets for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. When an indicator of impairment has occurred, we compare our management's estimate of undiscounted future cash flows attributable to the assets to the carrying value of the assets to determine whether an impairment has occurred. If an impairment of the carrying value has occurred, we determine the amount of the impairment recognized in the financial statements by estimating the fair value of the assets and recording a loss for the amount that the carrying value exceeds the estimated fair value.

Proved properties, including developed and undeveloped, are assessed for impairment using estimated future undiscounted cash flows on a field basis. If the undiscounted cash flows are less than the book value of the assets, then a subsequent analysis is performed using discounted cash flows. Additionally, our leasehold costs are evaluated for impairment if the proved property costs within a basin are impaired.

Costs of acquired unproved reserves are assessed for impairment using estimated fair value determined through the use of future discounted cash flows on a field basis and considering market participants' future drilling plans.

Judgments and assumptions are inherent in our management's estimate of undiscounted future cash flows and an asset's fair value. Additionally, judgment is used to determine the probability of sale with respect to assets considered for disposal. These judgments and assumptions include such matters as the estimation of oil and gas reserve quantities, risks associated with the different categories of oil and gas reserves, the timing of development and production, expected future commodity prices, capital expenditures, production costs, and appropriate discount rates.

Contingent liabilities

Due to the nature of our business, we are routinely subject to various lawsuits, claims and other proceedings. We recognize a liability in our consolidated financial statements when we determine that it is probable that a loss has been incurred and the amount can be reasonably estimated. If we determine that a loss is probable but lack information on which to reasonably estimate a loss, if any, or if we determine that a loss is only reasonably possible, we do not recognize a liability. We disclose the nature of loss contingencies that are potentially material but for which no liability has been recognized.

Asset retirement obligations

We record an asset and a liability upon incurrence equal to the present value of each expected future asset retirement obligation ("ARO"). These estimates include, as a component of future expected costs, an estimate of the price that a third party would demand, and could expect to receive, for bearing the uncertainties inherent in the obligations, sometimes referred to as a market risk premium. The ARO asset is depreciated in a manner consistent with the depreciation of the underlying physical asset. We measure changes in the liability due to passage of time by applying an interest method of allocation. This amount is recognized as an increase in the carrying amount of the liability and as a corresponding accretion expense in lease and facility operating expense included in costs and expenses.

Cash flows from revolving credit facilities

Proceeds and payments related to any borrowings under a revolving credit facility are reflected in the financing activities of the Consolidated Statements of Cash Flows on a gross basis.

Derivative instruments and hedging activities

We utilize derivatives to manage our commodity price risk. These instruments consist primarily of futures contracts, swap agreements, option contracts, and forward contracts involving short- and long-term purchases and sales of a physical energy commodity.

We report the fair value of derivatives, except those for which the normal purchases and normal sales exception has been elected, on the Consolidated Balance Sheets in derivative assets and derivative liabilities as either current or noncurrent. We determine the current and noncurrent classification based on the timing of expected future cash flows of individual trades. We report these amounts on a gross basis. Additionally, we report cash collateral receivables and payables with our counterparties on a gross basis.

The accounting for the changes in fair value of a commodity derivative can be summarized as follows:

Derivative Treatment	**Accounting Method**
Normal purchases and normal sales exception	Accrual accounting
Designated in a qualifying hedging relationship	Hedge accounting
All other derivatives	Mark-to-market accounting

We may elect the normal purchases and normal sales exception for certain short- and long-term purchases and sales of a physical energy commodity. Under accrual accounting, any change in the fair value of these derivatives is not reflected on the balance sheet after the initial election of the exception.

Certain gains and losses on derivative instruments included in the Consolidated Statements of Operations are netted together to a single net gain or loss, while other gains and losses are reported on a gross basis. Gains and losses recorded on a net basis include:

- unrealized gains and losses on all derivatives that are not designated as cash flow hedges related to production and for which we have not elected the normal purchases and normal sales exception;
- unrealized gains and losses on all derivatives that are not designated as cash flow hedges related to gas management and for which we have not elected the normal purchases and normal sales exception;
- realized gains and losses on all derivatives that settle financially;
- realized gains and losses on derivatives held for trading purposes; and
- realized gains and losses on derivatives entered into as a pre-contemplated buy/sell arrangement.

Realized gains and losses on derivatives that require physical delivery, as well as natural gas derivatives which are not held for trading purposes nor were entered into as a pre-contemplated buy/sell arrangement, are recorded on a gross basis. In reaching our conclusions on this presentation, we considered whether we act as principal in the transaction; whether we have the risks and rewards of ownership, including credit risk; and whether we have latitude in establishing prices.

Product revenues

Revenues for sales of oil, natural gas and natural gas liquids are recognized when the product is sold and delivered. Revenues from production in properties for which we have an interest with other producers are recognized based on the actual volumes sold during the period. Any differences between volumes sold and entitlement volumes, based on our net working interest, that are determined to be nonrecoverable through remaining production are recognized as accounts receivable or accounts payable, as appropriate. Our cumulative net natural gas imbalance position based on market prices as of December 31, 2015 and 2014 was insignificant . Additionally, natural gas revenues include $5 million in 2013 of realized gains from derivatives designated as cash flow hedges of our production sold.

Gas management revenues and expenses

Revenues for sales related to gas management activities are recognized when the product is sold and physically delivered. Gas management activities include the managing of various natural gas related contracts such as transportation and related hedges. The Company also sells oil, natural gas and NGLs purchased from working interest owners in operated wells and other area third-party producers. The revenues and expenses related to these marketing activities are reported on a gross basis as part of gas management revenues and costs and expenses.

Charges for unutilized transportation capacity included in gas management expenses were $38 million , $57 million and $61 million in 2015 , 2014 and 2013 , respectively.

Capitalization of interest

We capitalize interest during construction on projects with construction periods of at least three months and a total estimated project cost in excess of $1 million . We use the weighted average rate of our outstanding debt (see Note 8).

Income taxes

We file consolidated and combined federal and state income tax returns for the Company and its subsidiaries. We record deferred taxes for the differences between the tax and book basis of our assets as well as loss or credit carryovers to future years.

Deferred tax liabilities and assets are classified as noncurrent in a classified statement of financial position. As of December 31, 2015 , the Company adopted new guidance that seeks to simplify the presentation of deferred tax liabilities and assets and has applied its provisions prospectively thus prior periods were not retrospectively adjusted. See Note 9 for additional discussion.

Employee stock-based compensation

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant. Stock options generally become exercisable over a three -year period from the date of grant and generally expire ten years after the grant.

Restricted stock units are generally valued at market value on the grant date and generally vest over three years. Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

Earnings (loss) per common share

Basic earnings (loss) per common share is based on the sum of the weighted-average number of common shares outstanding and vested restricted stock units. Diluted earnings (loss) per common share includes any dilutive effect of stock options and nonvested restricted stock units (see Note 4).

Debt issuance costs

Debt issuance fees, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the effective interest and straight-line methods. The Company had total net debt issuance costs of $45 million and $28 million as of December 31, 2015 and December 31, 2014 , respectively. Approximately $31 million and $20 million of unamortized debt issuance costs related to the Company's senior unsecured notes and were reclassified from other noncurrent assets to long-term debt within our Consolidated Balance Sheets as of December 31, 2015 and December 31, 2014 , respectively. Debt issuance costs related to the senior unsecured Credit Facility remain recorded in other noncurrent assets on the Company's Consolidated Balance Sheets.

Note 2 . Acquisition

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

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

The majority of RKI's Delaware Basin leasehold is located in Loving County, Texas and Eddy County, New Mexico. RKI's assets in the Permian Basin include approximately 92,000 net acres in the core of the Permian's Delaware Basin. RKI operated 659 gross producing wells in the Delaware Basin with an average working interest of approximately 93 percent. RKI's average net daily production from its Delaware Basin properties for the year ended December 31, 2014 was 18.7 Mboe per day, 43 percent of which was oil, 34 percent natural gas and 23 percent NGLs. As of December 31, 2014, RKI reported proved reserves in the Delaware Basin of 101.5 MMboe, 40 percent of which was oil, 35 percent natural gas and 25 percent NGLs.

WPX funded the Acquisition with proceeds from a combination of debt, preferred stock and common stock offerings along with available cash on hand and borrowings under its revolving credit facility. See Notes 8 and 13 for further discussion on the financing of this transaction.

The following table presents the unaudited pro forma financial results for the years ended December 31, 2015 and 2014 as if the Acquisition and related financings had been completed January 1, 2014. In addition, the year ended December 31, 2015 has been adjusted to exclude $23 million of acquisition costs, $65 million loss on extinguishment of acquired debt and $16 million of acquisition bridge facility fees. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the Acquisition occurred on the date assumed or for the periods presented, nor is such information indicative of the Company's expected future results of operations.

	Years Ended December 31,	
	2015	2014
	(Millions)	
Revenues	$ 1,578	$ 2,905
Net income (loss) from continuing operations attributable to WPX Energy, Inc.	$ 81	$ 278

The Acquisition qualified as a business combination, and as a result, we must estimate the fair value of the underlying shares distributed, the assets acquired and the liabilities assumed as of the August 17, 2015 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements also utilize assumptions of market participants. We used a combination of market data, discounted cash flow models and replacement estimates in determining the fair value of the oil and gas properties and the related midstream assets. All of which include estimates and assumptions such as future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs. Deferred taxes must also be recorded for any differences between the assigned values and the carryover tax bases of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax bases of assets acquired and liabilities assumed and carryovers at the Acquisition date (see Note 9).

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

		Purchase Price Allocation
		(Millions)
Consideration:		
Cash, net of an estimated post-close settlement	$	1,251
Fair value of WPX common stock issued		296
Total consideration	$	1,547
Fair value of liabilities assumed:		
Accounts payable	$	104
Accrued liabilities		74
Deferred income taxes		692
Long-term debt		990
Asset retirement obligation		23
Total liabilities assumed as of December 31, 2015		1,883
Fair value of assets acquired:		
Cash and cash equivalents		51
Accounts receivable, net		80
Derivative assets, current		97
Derivative assets, noncurrent		34
Inventories		12
Other current assets		3
Properties and equipment(a)		3,149
Other noncurrent assets		4
Total assets acquired as of December 31, 2015		3,430
Net fair value of assets and liabilities	$	1,547

(a) Properties and equipment reflect the following as of the Acquisition date:

Proved properties	$	881
Unproved properties		2,108
Gathering, processing and other facilities		157
Other		3
Total	$	3,149

Note 3 . Discontinued Operations

On February 8, 2016 we signed an agreement with Terra Energy Partners LLC (“Terra”) to sell WPX Energy Rocky Mountain, LLC that holds our Piceance Basin operations for $910 million . The agreement also requires Terra to become financially responsible for approximately $104 million in transportation obligations held by our marketing company. Additionally, in accordance with the sales agreement and prior to closing, WPX will novate a portion of WPX's natural gas derivatives with a fair value of $82 million as of December 31, 2015 to WPX Energy Rocky Mountain, LLC. The parties closed this sale in April of 2016. These operations are included in our domestic results presented below. We also have certain pipeline capacity obligations held by our marketing company with total commitments for 2016 and thereafter of approximately $423 million . We may record a portion of these obligations if they meet the definition of exit activities in association with exiting the Piceance Basin. See Note 16 for a discussion of an agreement signed in May 2016 related to a portion of the remaining transportation obligations.

The Piceance Basin represented 52 percent of our total proved reserves at December 31, 2015 and 58 percent of our total production for 2015.

Significant transactions for the Piceance Basin Operations reflected in the tables below are as follows:

- As a result of market conditions including oil and natural gas prices in the fourth quarter of 2015, we performed impairment assessments of our proved producing properties. As a result of these assessments, which included the possibility of cash flows from a divestiture of the Piceance Basin, we recorded a total of $2,334 million in impairment charges associated with the Piceance Basin, of which approximately $2,308 million is recorded as a separate line on the table below and $26 million is included in exploration expenses.
- During the second quarter of 2014, we completed the sale of a portion of our working interests in certain Piceance Basin wells. Based on an estimated total value received at closing of $329 million which represented estimated final cash proceeds and an estimated fair value of incentive distribution rights we received, we recorded a $195 million loss on the sale in the second quarter of 2014. An additional $1 million loss on sale was recorded in the third quarter of 2014.
- Impairments of exploratory well costs and dry hole costs for 2014 include $67 million of impairment related to our Niobrara Shale well costs in the Piceance Basin.
- We recorded impairments in 2013, of $88 million in the Piceance Basin including impairments of capitalized costs of acquired unproved reserves of $19 million and $69 million in the third and fourth quarters, respectively, in the Kokopelli area.

In August 2015, we signed agreements for the sale of our Powder River Basin for $80 million , subject to closing adjustments. On September 1, 2015, we completed a portion of the Powder River Basin divestiture. The remaining portion of the divestiture, which relates to our equity method investment in Fort Union Gas Gathering, LLC, closed on October 30, 2015. We recorded a pre-tax loss of $15 million related to this transaction during 2015. During the first and second quarters of 2015, we recorded a total of $16 million in impairments of the net assets to a probability weighted-average of expected sales prices for the Powder River Basin. In addition, we retained certain firm gathering and treating obligations with total commitments of $104 million through 2020 related to the Powder River properties sold. These commitments had been in excess of our production throughput. At the time of closing, we also had certain pipeline capacity obligations held by our marketing company with total commitments through 2021 totaling $150 million , which were related to the Powder River Operation. With the closing of the Powder River Basin sale and exiting this basin, we recorded $187 million of expense related to these contracts, which is included as a separate line below. This expense is the estimated present value of the $254 million in payments associated with these contracts remaining as of the Powder River Basin sales date, and includes the fair value of estimated recoveries from third parties and discounting based on our risk adjusted borrowing rate. Offsetting liabilities of $54 million and $133 million were recorded in accrued and other current liabilities and other noncurrent liabilities, respectively, as of the closing date.

The results of our Piceance Basin and Powder River Basin operations are included in our domestic results presented below.

During the third quarter of 2014, we had signed an agreement to sell our Powder River Basin holdings. This sales agreement did not successfully close in March 2015 and we subsequently terminated the transaction with the counterparty. During third-quarter 2015, we received $13 million in escrow funds as a result of the terminated contract and this amount is included in Other-net expense below.

On October 3, 2014, we announced an agreement to sell our international interests for approximately $294 million subject to the successful consummation of the definitive merger agreement entered into between Pluspetrol Resources Corporation and Apco. On January 29, 2015 we completed this divestiture and received net proceeds of $291 million after expenses but before $17 million of cash on hand at Apco as of the closing date. These non-operated international holdings comprised our international segment. We recorded a pretax gain of $41 million related to this transaction during first quarter 2015.

Summarized Results of Discontinued Operations

For the year ended December 31, 2015	Domestic	International	Total
		(Millions)	
Total revenues	$ 577	$ 15	$ 592
Costs and expenses:			
Lease and facility operating	$ 99	$ 4	$ 103
Gathering, processing and transportation	257	—	257
Taxes other than income	18	3	21
Accrual for contract obligations retained and related accretion	190	—	190
Gas management	1	—	1
Exploration	26	—	26
Depreciation, depletion and amortization	412	—	412
Impairment of assets held for sale	2,324	—	2,324
General and administrative	44	1	45
Other—net	(10)	—	(10)
Total costs and expenses	3,361	8	3,369
Operating income (loss)	(2,784)	7	(2,777)
Investment income and other	5	1	6
Loss on sale of Powder River Basin	(15)	—	(15)
Gain on sale of international assets	—	41	41
Income (loss) from discontinued operations before income taxes	(2,794)	49	(2,745)
Provision (benefit) for income taxes	(1,020)	(3)	(1,023)
Income (loss) from discontinued operations	$ (1,774)	$ 52	$ (1,722)

For the year ended December 31, 2014	Domestic	International	Total
		(Millions)	
Total revenues	$ 1,159	$ 163	$ 1,322
Costs and expenses:			
Lease and facility operating	$ 142	$ 37	$ 179
Gathering, processing and transportation	327	1	328
Taxes other than income	54	28	82
Gas management, including charges for unutilized pipeline capacity	8	—	8
Exploration	72	4	76
Depreciation, depletion and amortization	458	42	500
Impairment of producing properties and costs of acquired unproved reserves	50	—	50
Loss on sale of working interest in the Piceance Basin	196	—	196
General and administrative	51	16	67
Other—net	(1)	12	11
Total costs and expenses	1,357	140	1,497
Operating income (loss)	(198)	23	(175)
Interest capitalized	1	—	1
Investment income and other	6	19	25
Income (loss) from discontinued operations before income taxes	(191)	42	(149)
Provision (benefit) for income taxes(a)	(71)	7	(64)
Income (loss) from discontinued operations	$ (120)	$ 35	$ (85)

(a) International income tax provision for 2014 is net of $18 million deferred tax benefit for the excess tax basis in our investment in Apco's stock.

For the year ended December 31, 2013	Domestic	International	Total
		(Millions)	
Total revenues	$ 1,104	$ 152	$ 1,256
Costs and expenses:			
Lease and facility operating	$ 162	$ 37	$ 199
Gathering, processing and transportation	357	3	360
Taxes other than income	49	24	73
Gas management, including charges for unutilized pipeline capacity	4	—	4
Exploration	7	7	14
Depreciation, depletion and amortization	552	34	586
Impairment of producing properties and costs of acquired unproved reserves	280	3	283
Gain on sale of Powder River Basin deep rights leasehold	(36)	—	(36)
General and administrative	57	14	71
Other—net	5	—	5
Total costs and expenses	1,437	122	1,559
Operating income (loss)	(333)	30	(303)
Interest capitalized	4	—	4
Investment income and other	4	21	25
Income (loss) from discontinued operations before income taxes	(325)	51	(274)
Provision (benefit) for income taxes(a)	(119)	31	(88)
Income (loss) from discontinued operations	$ (206)	$ 20	$ (186)

(a) International income tax provision for 2013 includes $10 million of deferred tax expense for the Argentina capital gains tax that was enacted in 2013.

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

As of December 31, 2015 the following table presents domestic assets classified as held for sale and liabilities associated with assets held for sale related to our Piceance Basin operations.

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

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

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

December 31, 2014	Domestic	International	Total
		(Millions)	
Assets classified as held for sale			
Current assets:			
Cash and cash equivalents	$ —	$ 29	$ 29
Accounts receivable	140	25	165
Inventories	15	7	22
Other	3	14	17
Total current assets	158	75	233
Investments	18	134	152
Properties and equipment (successful efforts method of accounting)(a)	7,082	445	7,527
Less—accumulated depreciation, depletion and amortization	(3,513)	(228)	(3,741)
Properties and equipment, net	3,569	217	3,786
Derivative assets	14	—	14
Other noncurrent assets	3	6	9
Total assets classified as held for sale—discontinued operations	$ 3,762	$ 432	$ 4,194
Total assets classified as held for sale—continuing operations (Note 5)	200	—	200
Total assets classified as held for sale on the Consolidated Balance Sheets	$ 3,962	$ 432	$ 4,394
Liabilities associated with assets held for sale			
Current liabilities:			
Accounts payable	$ 193	$ 34	$ 227
Accrued and other current liabilities	35	23	58
Total current liabilities	228	57	285
Deferred income taxes	—	13	13
Long-term debt	—	2	2
Asset retirement obligations	168	7	175
Other noncurrent liabilities	28	3	31
Total liabilities associated with assets held for sale—discontinued operations	$ 424	$ 82	$ 506
Total liabilities associated with assets held for sale—continuing operations (Note 4)	$ 2	$ —	$ 2
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets(b)	$ 426	$ 82	$ 508

(a) Domestic includes $45 million impairment in Powder River Basin of the net assets.

Noncontrolling interests in consolidated subsidiaries of $109 million as of December 31, 2014 , related to assets classified as held for sale.

Cash Flows Attributable to Discontinued Operations

Excluding taxes and changes to working capital, total cash provided by operating activities related to domestic discontinued operations was $184 million , $585 million and $478 million for 2015 , 2014 and 2013, respectively. Total cash used in investing activities related to domestic discontinued operations was $251 million , $512 million and $369 million for 2015 , 2014 and 2013, respectively. Cash provided by operating activities related to our international operations was $3 million , $65 million and $56 million for 2015 , 2014 and 2013, respectively. Total cash used in investing activities related our international operations was $15 million , $85 million and $43 million for 2015 , 2014 and 2013, respectively.

Note 4 . Earnings (Loss) Per Common Share from Continuing Operations

The following table summarizes the calculation of earnings per share.

	Years Ended December 31,		
	2015	2014	2013
	(Millions, except per-share amounts)		
Income (loss) from continuing operations attributable to WPX Energy, Inc.	$ (4)	$ 256	$ (993)
Less: Dividends on preferred stock	9	—	—
Income (loss) from continuing operations attributable to WPX Energy, Inc. available to common stockholders for basic and diluted earnings (loss) per common share	$ (13)	$ 256	$ (993)
Basic weighted-average shares	234.2	202.7	200.5
Effect of dilutive securities(a):			
Nonvested restricted stock units and awards	—	2.7	—
Stock options	—	0.9	—
Diluted weighted-average shares	234.2	206.3	200.5
Earnings (loss) per common share from continuing operations:			
Basic	$ (0.06)	$ 1.26	$ (4.95)
Diluted	$ (0.06)	$ 1.24	$ (4.95)

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Weighted-average nonvested restricted stock units and awards	1.3	—	2.5
Weighted-average stock options	0.1	—	1.1
Common shares issuable upon assumed conversion of 6.25% Series A mandatory convertible preferred stock (Note 13)	15.5	—	—

The table below includes information related to stock options that were outstanding at December 31, 2015, 2014 and 2013 but have been excluded from the computation of weighted-average stock options due to the option exercise price exceeding the fourth quarter weighted-average market price of our common shares.

	2015	2014	2013
Options excluded (millions)	2.6	1.4	0.4
Weighted-average exercise price of options excluded	$ 16.16	$ 18.42	$ 20.24
Exercise price range of options excluded	$11.46 - $21.81	$16.46 - $21.81	$20.21 - $20.97
Fourth quarter weighted-average market price	$ 7.43	$ 15.96	$ 19.97

For 2015, approximately 3.0 million nonvested restricted stock units and awards were antidilutive and were excluded from the computation of diluted weighted-average shares.

Note 5 . Asset Sales, Impairments, Other Expenses and Exploration Expenses

In 2014, we recorded a total of $15 million in impairment charges associated with exploratory well costs and producing properties recorded as a separate line on the Consolidated Statements of Operations. In 2013, we recorded a total of $1.1 billion in impairment charges of which $772 million is recorded as a separate line on the Consolidated Statements of Operations, $317 million is included in exploration expenses and $20 million is included in investment income, impairment of equity method investment and other. These impairments are discussed further in the sections below.

Asset Sales

In December 2015, we announced an agreement to sell our San Juan Basin gathering system for consideration of approximately $309 million to a portfolio company of ISQ Global Infrastructure Fund, a fund managed by I Squared Capital. The consideration reflects $285 million in cash, subject to closing adjustments, and a commitment estimated at $24 million in capital designated by the purchaser to expand the system to support WPX's development in the Gallup oil play. We are obligated to complete certain in-progress construction estimated to total approximately $13 million . Under the terms of the agreement, WPX will continue to operate, at the direction of the owner, the gathering system for an initial term of two years with the opportunity to continue in ensuing years. The parties expect to close in first-quarter 2016. Upon closing, the gathering system will consist of more than 220 miles of oil, gas and water gathering lines that WPX installed in conjunction with drilling in the Gallup oil play where it made a discovery in 2013. These assets totaled $40 million at December 31, 2015 and are classified as held for sale on the Consolidated Balance Sheets.

During the fourth quarter of 2015, we completed the sale of a North Dakota gathering system for approximately $185 million , subject to closing adjustments, to a private equity fund managed by the Ares EIF Group, a subsidiary of Ares Management, L.P. (NYSE: ARES). Under the terms of the agreement, a subsidiary of the buyer, Midstream Capital Partners, will manage the overall system and we will operate, at the direction of the owner, the system for a two year initial term and any renewal terms. The system currently gathers approximately 11,000 barrels per day of oil, approximately 6,500 Mcf per day of natural gas and approximately 5,000 barrels per day of water. As a result of this transaction, we recorded a net gain of $70 million in fourth-quarter 2015. In addition, we accrued approximately $25 million related to future construction obligations under the terms of the agreement, of which $22 million is reported in other noncurrent liabilities and $3 million is reported in accrued and other current liabilities on the Consolidated Balance Sheet. We also accrued approximately $33 million of deferred gain related to these obligations, of which $29 million is reported in other noncurrent liabilities and $4 million is reported in accrued and other current liabilities on the Consolidated Balance Sheet.

During May 2015, WPX completed the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast for approximately $209 million in cash. The transaction released us from various long-term natural gas purchase and sales obligations and approximately $390 million in future demand payment obligations associated with the transport position. As a result of this transaction, we recorded a net gain of $209 million in second-quarter 2015 on these executory contracts.

During the first quarter of 2015, we sold a portion of our Appalachian Basin operations and released certain firm transportation capacity to Southwestern Energy Company (NYSE: SWN) for approximately $288 million , subject to post-closing adjustments. Including an estimate of post-closing adjustments of $17 million , we recorded a net gain of $69 million in first-quarter 2015. The transaction included physical operations covering approximately 46,700 acres, roughly 50 MMcfe per day of net natural gas production and 63 horizontal wells. The assets were primarily located in the Appalachian Basin in Susquehanna County, Pennsylvania. The transaction also included the release of firm transportation capacity that we had under contract in the Northeast, primarily 260 MMcfe per day with Millennium Pipeline. Upon the transfer of the firm capacity, we were released from approximately $24 million per year in annual demand obligations associated with the transport.

Impairments

The following table presents a summary of significant impairments of producing properties and costs of acquired unproved reserves and impairment of equity method investments.

	Years Ended December 31,		
	2015	2014	2013
		(Millions)	
Impairment of producing properties and costs of acquired unproved reserves(a)	$ —	$ 15	$ 772
Impairment of equity method investment in Appalachian Basin	$ —	$ —	$ 20

(a) Excludes related impairments of unproved leasehold included in exploration expenses.

As a result of declines in forward crude oil and natural gas prices primarily during the fourth-quarter 2014 as compared to forward prices as of December 31, 2013, we performed impairment assessments of our proved producing properties and costs of acquired unproved reserves. Accordingly, we recorded the following impairments during 2014:

- $11 million impairment in the fourth quarter in the Green River Basin; and
- $4 million of impairments in the fourth quarter of other properties.

As a result of declines in forward natural gas prices primarily during the fourth-quarter 2013 as compared to forward prices as of December 31, 2012, we performed impairment assessments of our proved producing properties and capitalized cost of acquired unproved reserves. Accordingly, we recorded a $772 million impairment in the fourth quarter of 2013 of proved producing oil and gas properties in the Appalachian Basin.

The nature of the assets in the equity method investment in the Appalachian Basin is such that under normal circumstances an entity would capitalize and evaluate the assets as part of its producing properties. Therefore, our ability to recover the carrying amount of our investment lies in the value of our producing properties that utilize the assets of the entity. As a result of the 2013 impairment of the producing properties in the Appalachian Basin, we recorded an impairment of the equity method investment in 2013.

Our impairment analyses included an assessment of undiscounted and discounted future cash flows, which considered information obtained from drilling, other activities and natural gas reserve quantities (see Note 14).

Other Expenses

In December 2015, we plugged and abandoned the remaining wells serviced by a certain natural gas gathering system in the Appalachian Basin. As a result, we recorded approximately $23 million associated with the net present value of future obligations under the gathering agreement which is included in other-net on the Consolidated Statement of Operations.

During the first quarter of 2015, we executed a termination and settlement agreement to release us from a crude oil transportation and sales agreement in anticipation of entering into a different agreement with another third party with more favorable terms. As a result of this contract termination and settlement, we recorded an expense of approximately $22 million which is included in other—net on the Consolidated Statements of Operations.

Exploration Expenses

The following table presents a summary of exploration expenses.

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Geologic and geophysical costs	$ 7	$ 6	$ 12
Impairments of exploratory area well costs and dry hole costs	24	21	3
Unproved leasehold property impairments, amortization and expiration	54	74	402
Total exploration expenses	$ 85	$ 101	$ 417

Impairments of exploratory well costs and dry hole costs for 2015 include $24 million related to a non-core exploratory play where we no longer intend to continue exploration activities. Impairments of exploratory well costs and dry hole costs for 2014 include $16 million of impairments in other exploratory areas where management has determined to cease exploratory activities. The remaining amount in 2014 represents dry hole costs associated with exploratory wells where hydrocarbons were not detected.

Unproved leasehold property impairments, amortization and expiration in 2015 includes impairments of $26 million related to a non-core exploratory play where we no longer intend to continue exploration activities. Unproved leasehold property impairment, amortization and expiration in 2014 includes $41 million related to unproved leasehold costs in exploratory areas where we no longer intend to continue exploration activities. Unproved leasehold impairment, amortization and expiration in 2013 includes a $317 million impairment to estimated fair values of Appalachia leasehold associated with our impairment of the producing properties in the Appalachian Basin.

Note 6 . Properties and Equipment

Properties and equipment is carried at cost and consists of the following:

	Estimated Useful Life(a) (Years)	December 31, 2015	December 31, 2014
		(Millions)	
Proved properties	(b)	$ 5,520	$ 3,852
Unproved properties	(c)	2,342	349
Gathering, processing and other facilities	15-25	217	102
Construction in progress	(c)	198	368
Other	3-40	138	131
Total properties and equipment, at cost		8,415	4,802
Accumulated depreciation, depletion and amortization		(1,893)	(1,407)
Properties and equipment—net		$ 6,522	$ 3,395

(a) Estimated useful lives are presented as of December 31, 2015 .
(b) Proved properties are depreciated, depleted and amortized using the units-of-production method (see Note 1).
(c) Unproved properties and construction in progress are not yet subject to depreciation and depletion.

On August 17, 2015 we completed the Acquisition of RKI. See Note 2 for additional detail related to the Acquisition.

During 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 is included within our capital expenditures on the Consolidated Statements of Cash Flows.

Unproved properties consist primarily of non-producing leasehold in the Permian, San Juan and Williston Basins.

Asset Retirement Obligations

Our asset retirement obligations relate to producing wells, gas gathering well connections and related facilities. At the end of the useful life of each respective asset, we are legally obligated to plug producing wells and remove any related surface equipment and to cap gathering well connections at the wellhead and remove any related facility surface equipment.

A rollforward of our asset retirement obligations for the years ended 2015 and 2014 is presented below.

	2015	2014
	(Millions)	
Balance, January 1	$ 77	$ 67
Liabilities incurred	26	9
Liabilities settled	(2)	(1)
Liabilities associated with assets sold	—	—
Estimate revisions	(4)	(3)
Accretion expense(a)	5	5
Balance, December 31	$ 102	$ 77
Amount reflected as current	$ 3	$ 2

(a) Accretion expense is included in lease and facility operating expense on the Consolidated Statements of Operations.

Estimate revisions in 2014 are primarily associated with decreases in anticipated plug and abandonment costs.

Note 7 . Accounts Payable and Accrued and Other Current Liabilities

Accounts Payable

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

	December 31, 2015	December 31, 2014
	(Millions)	
Trade	$ 85	$ 171
Accrual for capital expenditures	65	235
Royalties	71	71
Affiliate payable for revenue related to assets held for sale	43	118
Other	14	43
	$ 278	$ 638

Accrued and other current liabilities

The following table presents a summary of our accrued and other current liabilities as of the dates indicated below.

	December 31, 2015	December 31, 2014
	(Millions)	
Taxes other than income taxes	$ 25	$ 10
Accrued interest	82	53
Compensation and benefit related accruals	61	55
Gathering and transportation	8	7
Gathering and transportation related to exited areas	56	6
Accrued income taxes	41	3
Other, including other loss contingencies	29	11
	$ 302	$ 145

Note 8 . Debt and Banking Arrangements

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

	December 31, 2015 (a)	December 31, 2014 (a)
	(Millions)	
5.250% Senior Notes due 2017	$ 355	$ 400
7.500% Senior Notes due 2020	500	—
6.000% Senior Notes due 2022	1,100	1,100
8.250% Senior Notes due 2023	500	—
5.250% Senior Notes due 2024	500	500
Credit facility agreement	265	280
Other	1	1
Total debt	$ 3,221	$ 2,281
Less: Current portion of long-term debt	1	1
Total long-term debt	$ 3,220	$ 2,280
Less: Debt issuance costs	$ 31	$ 20
Total long-term debt, net(b)	$ 3,189	$ 2,260

(a) Interest paid on debt totaled $120 million and $97 million for 2015 and 2014 , respectively.
(b) Debt issuance costs related to our Credit Facility are recorded in other noncurrent assets on the Consolidated Balance Sheets.

Subsequent to December 31, 2015 , we have borrowed an additional $110 million on our revolving credit facility. Also subsequent to December 31, 2015 and through February 25, 2016, we have repurchased $51 million of long-term notes due in 2017. See Note 16 for information regarding 2016 amendments to and amounts outstanding under our Credit Facility and the tendering of the outstanding Senior Notes due in 2017 subsequent to February 25, 2016.

Senior Notes

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

The notes are the Company’s senior unsecured obligations ranking equally with the Company’s other existing and future senior unsecured indebtedness. Interest is payable on the notes semiannually in arrears on February 1 and August 1 of each year commencing on February 1, 2016. The 2020 Notes will mature on August 1, 2020. The 2023 Notes will mature on August 1, 2023. The indenture contains covenants that, among other things, restrict the Company’s ability to grant liens on its assets and merge, consolidate or transfer or lease all or substantially all of its assets, subject to certain qualifications and exceptions. The net proceeds from the offering of the 2020 and 2023 Notes was approximately $494 million for each note after deducting the initial purchasers’ discounts and our offering expenses. The proceeds were used to repay borrowings under our Credit Facility.

In September 2014, we issued $500 million aggregate principal amount of 5.250% Senior Notes due 2024 (“the 2024 Notes”) pursuant to our automatic shelf registration statement on Form S-3 filed with the Securities and Exchange Commission. The 2024 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 net proceeds from the offering of the 2024 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.

In November 2011, we issued $400 million aggregate principal amount of 5.250% Senior Notes due 2017 (the “2017 Notes”) and $1.1 billion aggregate principal amount of 6.000% Senior Notes due 2022 (the “2022 Notes”) pursuant to a private offering, and in June 2012 we exchanged these notes for registered 2017 Notes and 2022 Notes. The 2017 Notes and 2022 Notes were issued under an indenture between us and The Bank of New York Mellon Trust Company, N.A., as trustee.

The terms of the indentures governing our notes are substantially identical.

Optional Redemption. We have the option prior to maturity for the 2017 Notes, prior to July 1, 2020 for the 2020 Notes, prior to October 15, 2021 for the 2022 Notes, prior to June 1, 2023 for the 2023 Notes and prior to June 15, 2024 for the 2024 Notes to redeem some or all of such notes at a specified “make whole” premium as described in the indenture(s) governing the notes to be redeemed. We also have the option at any time or from time to time on or after July 1, 2020 to redeem the 2020 Notes, or on or after October 15, 2021 to redeem the 2022 Notes, or on or after June 1, 2023 to redeem the 2023 Notes and or on or after June 15, 2024, to redeem the 2024 Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes to be redeemed, plus accrued and unpaid interest thereon to the redemption date as more fully described in the indenture.

During 2015 , we repurchased approximately $45 million of the 2017 Notes. The Company's next debt maturity does not occur until 2020.

Change of Control. If we experience a change of control (as defined in the indentures governing the notes) accompanied by a specified rating decline, we must offer to repurchase the notes of such series at 101% of their principal amount, plus accrued and unpaid interest.

Covenants. The terms of the indentures governing our notes 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 indentures also require us to file with the trustee and the SEC certain documents and reports within certain time limits set forth in the indentures. However, these limitations and requirements are subject to a number of important qualifications and exceptions. The indentures do 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 indentures with respect to the notes of any series:

(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 Agreement

Including the impact of amendments in July 2015, we have a $1.75 billion five -year senior unsecured revolving credit facility agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the “Credit Facility”). The Credit Facility matures on October 28, 2019 . The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of December 31, 2015 , the weighted average variable interest rate was 2.20% on the $265 million outstanding under the Credit Facility Agreement.

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

Under the amended revolving Credit Facility, if the Company’s Corporate Rating is (a) BB- or worse by S&P and Ba3 or worse by Moody’s or (b) B+ or worse by S&P or B1 or worse by Moody’s, the Company will be required to maintain a ratio of net present value of projected future cash flows from proved reserves, calculated in accordance with the terms of the Credit Facility, to Consolidated Indebtedness of at least 1.10 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and at least 1.50 to 1.00 thereafter unless and until (i) the Company’s Corporate Rating is (A) BBB- or better with S&P (without negative outlook or negative watch) or (B) Baa3 or better by Moody’s (without negative outlook or negative watch) and (ii) the other of the two Corporate Ratings is at least BB+ by S&P or Ba1 by Moody’s. As of December 31, 2015 , our credit rating with S&P was BB, positive outlook and our credit rating with Moody's is Ba1, negative outlook. Subsequent to December 31, 2015 , our credit ratings were downgraded to BB-, negative outlook and B2, negative outlook with S&P and Moody's, respectively.

In addition, the Company is required to maintain a ratio of Consolidated Net Indebtedness to Consolidated EBITDAX of not greater than 4.50 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and 4.00 to 1.00 thereafter, unless at such time the Company’s Corporate Ratings are equal to, or better than, Baa3 or BBB- by at least one of S&P and Moody’s and not less than BB+ or Ba1 by the other such agency. Furthermore, the ratio of Consolidated Indebtedness to Consolidated Total Capitalization is not permitted to be greater than 60 percent and the Company may not permit the ratio of Consolidated EBITDAX to Consolidated Interest Charges to be less than 2.5 to 1.00 for the life of the agreement.

As of December 31, 2015 , we were in compliance with our financial covenants and had full access to the Credit Facility.

Interest on borrowings under the Credit Facility Agreement are payable at rates per annum equal to, at our option: (1) a fluctuating base rate equal to the Alternate Base Rate plus the Applicable Rate, or (2) a periodic fixed rate equal to LIBOR plus the Applicable Rate. The Alternate Base Rate will be the highest of (i) the federal funds rate plus 0.5% , (ii) The Wells Fargo Bank, National Association, publicly announced prime rate, and (iii) one-month LIBOR plus 1.0% . The Applicable Rate is defined in the Credit Facility Agreement and is determined by which interest rate we select and the ratings of our long-term unsecured debt. At December 31, 2015 , the Applicable Rate was 1.875% on our LIBOR loans and 0.875% on our alternate base rate loans. Additionally, we will be required to pay a commitment fee, based on the ratings of our long-term unsecured debt, on the unused portion of the commitments under the Credit Facility Agreement. At December 31, 2015 , the commitment fee rate was 0.30% .

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

The Credit Facility Agreement includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties in any material respect when made or when deemed made, violation of covenants, cross payment-defaults, cross acceleration, bankruptcy and insolvency events, certain unsatisfied judgments and a change of control. If an event of default with respect to us occurs under the Credit Facility Agreement, the lenders will be able to terminate the commitments and accelerate the maturity of any loans outstanding under the Credit Facility Agreement at the time, in addition to the exercise of other rights and remedies available.

Letters of Credit

WPX has also entered into three bilateral, uncommitted letter of credit (“LC”) agreements most of which expire throughout 2016. These LC agreements provide WPX the ability to meet various contractual requirements and incorporate terms similar to those found in the Credit Facility Agreement. At December 31, 2015 , a total of $233 million in letters of credit have been issued, a majority of which support interstate pipeline contracts. If these letter of credit agreements are not renewed, we may issue letters of credit under our Credit Facility.

Note 9 . Provision (Benefit) for Income Taxes

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

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Provision (benefit):			
Current:			
Federal	$ (4)	$ 8	$ (28)
State	7	1	(5)
	3	9	(33)
Deferred:			
Federal	12	134	(496)
State	9	5	(38)
	21	139	(534)
Total provision (benefit)	$ 24	$ 148	$ (567)

The following table provides reconciliations from the provision (benefit) for income taxes from continuing operations at the federal statutory rate to the realized provision (benefit) for income taxes.

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Provision (benefit) at statutory rate	$ 7	$ 141	$ (550)
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	4	4	(25)
State income tax legislation change (net of federal benefit)	—	9	—
Effective state income tax rate change (net of federal benefit)	7	(9)	(3)
Other	6	3	11
Provision (benefit) for income taxes	$ 24	$ 148	$ (567)

The following table includes significant components of deferred tax liabilities and deferred tax assets.

	December 31,	
	2015	2014
	(Millions)	
Deferred tax liabilities:		
Properties and equipment	$ 988	$ 738
Derivatives, net	155	170
Other, net	1	17
Total deferred tax liabilities	1,144	925
Deferred tax assets:		
Accrued liabilities and other	248	124
Alternative minimum tax credits	114	60
Loss carryovers	441	51
Other, net	—	32
Total deferred tax assets	803	267
Less: valuation allowance	124	114
Total net deferred tax assets	679	153
Net deferred tax liabilities	$ 465	$ 772

Net cash payments (refunds) for income taxes were $(8) million , $9 million and $(26) million in 2015, 2014 and 2013, respectively.

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

Significant changes to our operations during 2015 resulted in changes to our anticipated future state apportionment for our estimated state deferred tax liability. As a result of these changes and the differing state tax rates, we accrued an additional $7 million of deferred tax expense in 2015. Tax reform legislation that was enacted by the state of New York on March, 31, 2014 had an impact on us as a result of our marketing activities in the state. As a result, we recorded an additional $9 million of deferred tax expense in the first quarter of 2014. However, due to announced asset sales in fourth-quarter 2014, our state effective tax rate decreased resulting in a $9 million deferred tax benefit.

The acquisition of the stock of RKI in third-quarter 2015 (see Note 2) resulted in an increase to our deferred tax liabilities of $693 million as of the Acquisition date. Included in this amount are deferred tax assets for federal net operating loss (“NOL”) carryovers of $125 million , minimum tax credits of $50 million and state NOL carryovers of $7 million .

The Company has federal NOL carryovers of approximately $902 million at December 31, 2015, including the RKI NOL, that will not begin to expire until 2032 . In addition, we have $47 million of capital loss carryovers at December 31, 2015, that will begin to expire in 2020 .

The Company has state NOL carryovers, including the RKI carryovers, of approximately $2.0 billion and $875 million at 2015 and 2014, respectively, of which more than 98 percent expire after 2029 .

The ability of WPX to utilize loss carryovers or minimum tax credits to reduce future federal taxable income and income tax is subject to various limitations under the Internal Revenue Code (the Code). The utilization of such carryovers may be limited upon the occurrence of certain ownership changes during any three -year period resulting in an aggregate change of more than 50 percent in beneficial ownership (an Ownership Change). As of December 31, 2015, we do not believe that an Ownership Change has occurred for WPX, but an Ownership Change did occur for RKI effective with the Acquisition. Therefore, there is an annual limitation on the benefit that WPX can claim from RKI carryovers that arose prior to the Acquisition.

We have recorded valuation allowances against deferred tax assets attributable primarily to certain state NOL carryovers as well as our federal capital loss carryover. When assessing the need for a valuation allowance, we primarily consider future reversals of existing taxable temporary differences. To a lesser extent we also consider future taxable income exclusive of reversing temporary differences and carryovers, and tax-planning strategies that would, if necessary, be implemented to accelerate taxable amounts to utilize expiring carryovers. The ultimate amount of deferred tax assets realized could be materially different from those recorded, as influenced by future operational performance, potential changes in jurisdictional income tax laws and the circumstances surrounding the actual realization of related tax assets. Valuation allowances that we have recorded are due to our expectation that we will not have sufficient income, or income of a sufficient character, in those jurisdictions to which the associated deferred tax asset applies.

In previous periods, our deferred income tax liabilities and assets have been separated into current and noncurrent amounts. The company adopted ASU No. 2015-17: *Balance Sheet Classification of Deferred Taxes* as of December 31, 2015. See Note 1 for further discussion.

Pursuant to our tax sharing agreement with The Williams Companies, Inc. (“Williams”), we remain responsible for the tax from audit adjustments related to our business for periods prior to our spin-off from Williams on December 31, 2011. In addition, the alternative minimum tax credit deferred tax asset that was allocated to us by Williams at the time of the spin-off could change due to audit adjustments unrelated to our business . The 2011 consolidated tax filing by Williams is currently being audited by the IRS and is the only pre spin-off period for which we continue to have exposure to audit adjustments as part of Williams. It is uncertain when the IRS will complete that audit.

The Company’s policy is to recognize related interest and penalties as a component of income tax expense. The amounts accrued for interest and penalties are insignificant.

As of December 31, 2015 , the Company has no significant unrecognized tax benefits. During the next 12 months , we do not expect ultimate resolution of any uncertain tax position will result in a significant increase or decrease of an unrecognized tax benefit.

Note 10 . Contingent Liabilities and Commitments

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 accounting process under the standard and have obtained the court's approval. However, as we continue to believe our royalty calculations have been properly determined in accordance with the appropriate contractual arrangements and Colorado law, we have appealed this matter to the Colorado Court of Appeals. Plaintiffs have now filed a second class action lawsuit in the District Court, Garfield County containing similar allegations but related to subsequent time periods. The parties have agreed to stay this new lawsuit pending resolution of the first lawsuit in the Colorado Court of Appeals.

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

Other producers have been pursuing administrative appeals with a federal regulatory agency and have been in discussions with a state agency in New Mexico regarding certain deductions, comprised primarily of processing, treating and transportation costs, used in the calculation of royalties. Although we are not a party to those matters, we are monitoring them to evaluate whether their resolution might have the potential for unfavorable impact on our results of operations. Certain outstanding issues in those matters could be material to us. We received notice from the U.S. Department of Interior Office of Natural Resources Revenue (“ONRR”) in the fourth quarter of 2010, intending to clarify the guidelines for calculating federal royalties on conventional gas production applicable to our federal leases in New Mexico. The guidelines for New Mexico properties were revised slightly in September 2013 as a result of additional work performed by the ONRR. The revisions did not change the basic function of the original guidance. The ONRR’s guidance provides its view as to how much of a producer’s bundled fees for transportation and processing can be deducted from the royalty payment. We believe using these guidelines would not result in a material difference in determining our historical federal royalty payments for our leases in New Mexico. No similar specific guidance has been issued by ONRR for leases in Colorado though such guidelines are expected in the future. However, the timing of any such guidance is uncertain and, independent of the issuance of additional guidance, ONRR asked producers to attempt to evaluate the deductibility of these fees directly with the midstream companies that transport and process gas. The issuance of similar guidelines in Colorado and other states could affect our previous royalty payments, and the effect could be material to our results of operations. Interpretive guidelines on the applicability of certain deductions in the calculation of federal royalties are extremely complex and may vary based upon the ONRR’s assessment of the configuration of processing, treating and transportation operations supporting each federal lease. Correspondence in 2009 with the ONRR’s predecessor did not take issue with our calculation regarding the Piceance Basin assumptions, which we believe have been consistent with the requirements. From January 2009 through December 2015, our deductions used in the calculation of the royalty payments in states other than New Mexico associated with conventional gas production total approximately $114 million .

Environmental matters

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

Matters related to Williams’ former power business

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

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

In the other cases, on July 18, 2011, the Nevada district court granted our joint motions for summary judgment to preclude the plaintiffs’ state law claims because the federal Natural Gas Act gives the FERC exclusive jurisdiction to resolve those issues. The court also denied the plaintiffs’ class certification motion as moot. The plaintiffs appealed to the United States Court of Appeals for the Ninth Circuit. On April 10, 2013, the United States Court of Appeals for the Ninth Circuit issued its opinion in the Western States Antitrust Litigation holding that the Natural Gas Act does not preempt the plaintiffs’ state antitrust claims and reversing the summary judgment previously entered in favor of the defendants. The U.S. Supreme Court granted Defendants' writ of certiorari. On April 21, 2015, the U.S. Supreme Court determined that the state antitrust claims are not preempted by the federal Natural Gas Act. Because of the uncertainty around pending unresolved issues, including an insufficient description of the purported classes and other related matters, we cannot reasonably estimate a range of potential exposures at this time.

Other Indemnifications

Pursuant to various purchase and sale agreements relating to divested businesses and assets, we have indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from us. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations that we have provided.

At December 31, 2015 , we have not received a claim against any of these indemnities and thus have no basis from which to estimate any reasonably possible loss. Further, we do not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on our future financial position. However, if a claim for indemnity is brought against us in the future, it may have a material adverse effect on our results of operations in the period in which the claim is made.

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

Summary

As of December 31, 2015 and December 31, 2014, the Company had accrued approximately $17 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.

Commitments

As part of managing our commodity price risk, we utilize contracted pipeline capacity to move our natural gas production and third party gas purchases to other locations in an attempt to obtain more favorable pricing differentials. Our commitments under these contracts as of December 31, 2015 are as follows:

	(Millions)
2016	$ 140
2017	130
2018	116
2019	104
2020	91
Thereafter	105
Total	$ 686

In conjunction with our exit of the Powder River Basin, we recorded liabilities associated with certain pipeline capacity obligations held by our marketing company of which $29 million and $84 million is recorded in accrued and other current liabilities and other noncurrent liabilities, respectively, as of December 31, 2015. Commitments related to these pipeline agreements for 2016 and beyond total $139 million and are included in the table above. Also included in the table is approximately $527 million of transportation obligations primarily associated with our Piceance Basin of which $104 million will become the financial responsibility of the purchaser (see Note 3 of Notes to Consolidated Financial Statements). See Note 16 for a discussion of an agreement signed in May 2016 related to a portion of the remaining transportation obligations.

We have certain commitments, for natural gas gathering and treating services, which total $524 million , including approximately $106 million associated with our Piceance Basin operations that will be assumed by the purchaser, $92 million associated with our exit from the Powder River Basin and $33 million associated with gathering commitments in a portion of our Appalachian Basin operations (see Notes 3 and 5 of the Notes to Consolidated Financial Statements). Liabilities associated with the Powder River Basin of $19 million and $40 million were recorded in accrued and other current liabilities and other noncurrent liabilities, respectively, as of December 31, 2015. In addition, we accrued approximately $23 million related to the abandonment of a portion of our Appalachian Basin operations, of which $20 million is recorded in other noncurrent liabilities as of December 31, 2015. Commitments other than those associated with our Piceance Basin operations will be settled over approximately eight years .

Future minimum annual rentals under noncancelable operating leases as of December 31, 2015, are payable as follows:

	(Millions)
2016	$ 28
2017	23
2018	12
2019	7
2020	7
Thereafter	9
Total	$ 86

Total rent expense, excluding amounts capitalized, was $28 million , $26 million and $23 million in 2015, 2014 and 2013, respectively. Rent charges incurred for drilling rig rentals are capitalized under the successful efforts method of accounting; however, charges for rig release penalties or long term standby charges are expensed as incurred.

Note 11 . Employee Benefit Plans

WPX has a defined contribution plan which matches dollar-for-dollar up to the first 6 percent of eligible pay per period. Employees also receive a non-matching annual employer contribution of equal to 8 percent of eligible pay if they are age 40 or older and 6 percent of eligible pay if they are under age 40. Total contributions to this plan were $15 million , $17 million and $16 million for 2015 , 2014 and 2013 , respectively. Approximately $9 million and $10 million were included in accrued and other current liabilities at December 31, 2015 and December 31, 2014 , respectively, related to the non-matching annual employer contribution.

Note 12 . Stock-Based Compensation

WPX Energy, Inc. 2013 Incentive Plan

We have an equity incentive plan (“2013 Incentive Plan”) and an employee stock purchase plan (“ESPP”). The 2013 Incentive Plan authorizes the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units and other stock-based awards. The number of shares of common stock authorized for issuance pursuant to all awards granted under the 2013 Incentive Plan is 19.6 million shares. The 2013 Incentive Plan is administered by either the full Board of Directors or a committee as designated by the Board of Directors, determined by the grant. Our employees, officers and non-employee directors are eligible to receive awards under the 2013 Incentive Plan.

The ESPP allows domestic employees the option to purchase WPX common stock at a 15 percent discount through after-tax payroll deductions. The purchase price of the stock is the lower of either the first or last day of the biannual offering periods, followed with the 15 percent discount. The maximum number of shares that shall be made available under the purchase plan is 1 million shares, subject to adjustment for stock splits and similar events. The first offering under the ESPP commenced on March 1, 2012 and ended on June 30, 2012 . Subsequent offering periods are from January through June and from July through December. Employees purchased 191 thousand shares at an average price of $7.05 per share during 2015 .

Employee stock-based awards

Stock options are valued at the date of award, which does not precede the approval date, and compensation cost is recognized on a straight-line basis, net of estimated forfeitures, over the requisite service period. The purchase price per share for stock options may not be less than the market price of the underlying stock on the date of grant.

Stock options generally become exercisable over a three -year period from the date of grant and generally expire ten years after the grant.

Restricted stock units are generally valued at fair value on the grant date and generally vest over three years . Restricted stock unit compensation cost, net of estimated forfeitures, is generally recognized over the vesting period on a straight-line basis.

Total stock-based compensation expense for the years ended December 31, 2015 , 2014 and 2013 was $35 million , $35 million and $31 million , respectively. Stock-based compensation expense is reflected in general and administrative expense; however, approximately $4 million , $5 million and $4 million for the years ended December 31, 2015 , 2014 and 2013 , respectively, is included in discontinued operations. Measured but unrecognized stock-based compensation expense at December 31, 2015 was $37 million . This amount is comprised of $1 million related to stock options and $36 million related to restricted stock units. These amounts are expected to be recognized over a weighted-average period of 1.8 years.

Stock Options

The following summary reflects stock option activity and related information for the year ended December 31, 2015 .

	WPX Plan		
Stock Options	**Options**	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value**
	(Millions)		**(Millions)**
Outstanding at December 31, 2014(a)	3.1	$ 14.80	$ 2
Granted	—	$ —	
Exercised	(0.2)	$ 10.33	
Forfeited	—	$ —	
Outstanding at December 31, 2015	2.9	$ 15.07	$ —
Exercisable at December 31, 2015	2.7	$ 14.75	$ —

(a) Includes approximately 137 thousand shares held by Williams' employees at a weighted average price of $10.64 per share at December 31, 2014 .

The total intrinsic value of options exercised during the years ended December 31, 2015 , 2014 and 2013 was $319 thousand , $13 million and $5 million , respectively.

The following summary provides additional information about stock options that are outstanding and exercisable at December 31, 2015 .

	WPX Plan					
	Stock Options Outstanding			Stock Options Exercisable		
Range of Exercise Prices	**Options**	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Life**	**Options**	**Weighted-Average Exercise Price**	**Weighted-Average Remaining Contractual Life**
	(Millions)		**(Years)**	**(Millions)**		**(Years)**
$ 6.02 to $12.32	0.9	$ 9.79	3.0	0.9	$ 9.79	3.0
$ 14.41 to $17.47	1.2	$ 15.97	5.0	1.1	$ 15.92	4.6
$18.16 to $19.95	0.3	$ 18.21	6.4	0.3	$ 18.21	6.4
$20.21 to $21.81	0.5	$ 20.62	4.0	0.4	$ 20.37	2.8
Total	2.9	$ 15.07	4.4	2.7	$ 14.75	4.0

The estimated fair value at date of grant of options for our common stock in each respective year, using the Black-Scholes option pricing model, is as follows:

	WPX Plan		
	2015	2014	2013
Weighted-average grant date fair value of options granted	$ —	$ 18.94	$ 6.04
Weighted-average assumptions:			
Dividend yield	—	—	—
Volatility	—%	43.0%	42.8%
Risk-free interest rate	—%	1.85%	1.06%
Expected life (years)	0.0	5.9	6.0

For 2014 and 2013 , we determined that the Williams stock option grant data was not relevant for valuing WPX options; therefore the Company used the SEC simplified method. The expected volatility is based primarily on the historical volatility of comparable peer group stocks. The risk free interest rate is based on the U.S. Treasury Constant Maturity rates as of the grant date. The expected life is assumed based on the SEC simplified method.

Cash received from stock option exercises was $2 million , $14 million and $4 million during 2015 , 2014 and 2013 , respectively.

Nonvested Restricted Stock Units

The following summary reflects nonvested restricted stock unit activity and related information for the year ended December 31, 2015 .

	WPX Plan	
Restricted Stock Units	**Shares**	**Weighted-Average Fair Value(a)**
	(Millions)	
Nonvested at December 31, 2014	5.1	$ 17.58
Granted	3.1	$ 10.24
Forfeited	(0.1)	$ 14.89
Vested	(2.2)	$ 18.34
Nonvested at December 31, 2015	5.9	$ 13.34

(a) Performance-based shares are primarily valued using a valuation pricing model. However, certain of these shares were valued using the end-of-period market price until certification that the performance objectives were completed or a value of zero once it was determined that it was unlikely that performance objectives would be met. All other shares are valued at the grant-date market price, less dividends projected to be paid over the vesting period.

Other restricted stock unit information

	WPX Plan		
	2015	2014	2013
Weighted-average grant date fair value of restricted stock units granted during the year, per share	$ 10.24	$ 18.37	$ 14.97
Total fair value of restricted stock units vested during the year (millions)	$ 40	$ 33	$ 18

Performance-based shares granted represent 25 percent of nonvested restricted stock units outstanding at December 31, 2015 . These grants may be earned at the end of a three -year period based on actual performance against a performance target. Expense associated with these performance-based grants is recognized in periods after performance targets are established. Based on the extent to which certain financial targets are achieved, vested shares may range from zero percent to 200 percent of the original grant amount.

Note 13 . Stockholders' Equity

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

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

Common Stock

Each share of our common stock entitles its holder to one vote in the election of each director. No share of our common stock affords any cumulative voting rights. Holders of our common stock will be entitled to dividends in such amounts and at such times as our Board of Directors in its discretion may declare out of funds legally available for the payment of dividends. No dividends on our common stock were declared or paid for 2015 , 2014 or 2013 . No shares of common stock are subject to redemption or have preemptive rights to purchase additional shares of our common stock or other securities.

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

Preferred Stock

Our amended and restated certificate of incorporation authorizes our Board of Directors to establish one or more series of preferred stock. Unless required by law or by any stock exchange on which our common stock is listed, the authorized shares of preferred stock will be available for issuance without further action. Rights and privileges associated with shares of preferred stock are subject to authorization by our Board of Directors and may differ from those of any and all other series at any time outstanding. As of December 31, 2015 , there were 7 million shares of our 6.25% series A Mandatory Convertible Preferred Stock (as described below) issued and outstanding.

Series A Mandatory Convertible Preferred Stock

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

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

Each share of our Mandatory Convertible Preferred Stock has a liquidation preference of $50 pursuant to the Certificate of Designations and unless converted or redeemed earlier each share of our Mandatory Convertible Preferred Stock will automatically convert on the mandatory conversion date, which is the third business day immediately following the last trading day of the final averaging period into between 4.1254 and 4.9504 shares of our common stock (respectively, the "minimum conversion rate" and "maximum conversion rate"), subject to anti-dilution adjustments. The number of shares of our common stock issuable on conversion will be determined based on the average volume weighted average price per share of our common stock over the 20 consecutive trading day period beginning on, and including, the 23rd scheduled trading day immediately preceding July 31, 2018, which we refer to as the "final averaging period." Other than during a fundamental change conversion period, at any time prior to July 31, 2018, a holder may convert one share of our Mandatory Convertible Preferred Stock into a number of shares of our common stock equal to the minimum conversion rate of 4.1254 , subject to anti-dilution adjustments. If a holder converts one share of our Mandatory Convertible Preferred Stock during a specified period beginning on the effective date of a fundamental change (as described in the offering documents), the conversion rate will be adjusted under certain circumstances, and such holder will also be entitled to a make-whole dividend amount (as described in the offering documents).

On October 2, 2015, our Board of Directors approved a quarterly dividend of $0.85938 per share to holders of our Mandatory Convertible Preferred Stock. The dividend was paid on November 2, 2015, to holders of record of our Mandatory Convertible Preferred Stock at the close of business on October 15, 2015. On November 12, 2015, our Board of Directors approved a quarterly dividend of $0.78125 per share to holders of our Mandatory Convertible Preferred Stock. The dividend was paid on February 1, 2016, to holders of record of our Mandatory Convertible Preferred Stock at the close of business on January 15, 2016.

Note 14 . Fair Value Measurements

Fair value is the amount received from the sale of an asset or the amount paid to transfer a liability in an orderly transaction between market participants (an exit price) at the measurement date. Fair value is a market-based measurement considered from the perspective of a market participant. We use market data or assumptions that we believe market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation. These inputs can be readily observable, market corroborated or unobservable. We apply both market and income approaches for recurring fair value measurements using the best available information while utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy prioritizes the inputs used to measure fair value, giving the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). We classify fair value balances based on the observability of those inputs. The three levels of the fair value hierarchy are as follows:

- Level 1—Quoted prices for identical assets or liabilities in active markets that we have the ability to access. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Our Level 1 measurements primarily consist of financial instruments that are exchange traded.
- Level 2—Inputs are other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable. These inputs are either directly observable in the marketplace or indirectly observable through corroboration with market data for substantially the full contractual term of the asset or liability being measured. Our Level 2 measurements primarily consist of over-the-counter ("OTC") instruments such as forwards, swaps and options. These options, which hedge future sales of production, are structured as costless collars, calls or swaptions and are financially settled. They are valued using an industry standard Black-Scholes option pricing model. 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.
- Level 3—Inputs that are not observable for which there is little, if any, market activity for the asset or liability being measured. These inputs reflect management's best estimate of the assumptions market participants would use in determining fair value. Our Level 3 measurements consist of instruments valued using industry standard pricing models and other valuation methods that utilize unobservable pricing inputs that are significant to the overall fair value.

In valuing certain contracts, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. For disclosure purposes, assets and liabilities are classified in their entirety in the fair value hierarchy level based on the lowest level of input that is significant to the overall fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy levels.

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 approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
			(Millions)				(Millions)	
Energy derivative assets	$ —	$ 359	$ —	$ 359	$ 14	$ 503	$ 5	$ 522
Energy derivative liabilities	$ —	$ 15	$ —	$ 15	$ 32	$ 10	$ —	$ 42
Total debt(a)	$ —	$ 2,495	$ —	$ 2,495	$ —	$ 2,218	$ —	$ 2,218

(a) The carrying value of total debt, excluding capital leases and debt issuance costs, was $3,220 million and $2,280 million as of December 31, 2015 and 2014 , respectively.

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

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

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

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

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

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

Certain instruments trade with lower availability of pricing information. These instruments are valued with a present value technique using inputs that may not be readily observable or corroborated by other market data. These instruments are classified within Level 3 when these inputs have a significant impact on the measurement of fair value. The instruments included in Level 3 at December 31, 2015, 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 between Level 1 and Level 2 occurred during the years ended December 31, 2015 or 2014.

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

	Years ended December 31,		
	2015	2014	2013
		(Millions)	
Beginning balance	$ 5	$ —	$ (1)
Realized and unrealized gains (losses):			
Included in income (loss) from continuing operations	(1)	5	(2)
Included in other comprehensive income (loss)	—	—	—
Purchases, issuances, and settlements	(4)	—	3
Transfers out of Level 3	—	—	—
Ending balance	$ —	$ 5	$ —
Unrealized gains included in income (loss) from continuing operations relating to instruments still held at December 31	$ —	$ 5	$ (1)

Realized and unrealized gains (losses) included in income (loss) from continuing operations for the above periods are reported in revenues in our Consolidated Statements of Operations.

As previously noted, we evaluate our long-lived assets for impairment when events or changes in circumstances indicate, in our management's judgment, that the carrying value of such assets may not be recoverable. On several occasions in the past three years, we considered the significant declines in forward natural gas, oil and NGL prices as compared to the previous respective period's forward prices to be indicators of a potential impairment. As a result, we assessed the carrying value of our producing properties and costs of acquired unproved reserves for impairments as of the dates of those declines. Our assessments utilized estimates of future cash flows, including in some instances potential disposition proceeds. Significant judgments and assumptions in these assessments include estimates of proved, probable and possible reserve quantities, estimates of future commodity prices (developed in consideration of market information, internal forecasts and published forward prices adjusted for locational basis differentials), expectation for market participant drilling plans, expected capital costs and an applicable discount rate commensurate with the risk of the underlying cash flow estimates. In each of the three years ended December 31, 2015 , our assessments identified certain properties with a carrying value in excess of their calculated fair values and as a result, we recorded impairment charges. The following table presents impairments associated with certain assets that have been measured at fair value on a nonrecurring basis within Level 3 of the fair value hierarchy.

	Total losses for the years ended December 31,		
	2015 (a)	2014 (b)	2013 (c)
		(Millions)	
Impairments:			
Producing properties and costs of acquired unproved reserves (Note 3 and Note 5)	$ 2,308	$ 20	$ 1,055
Unproved leasehold	26	—	317
Equity method investment (Note 5)	—	—	20
	$ 2,334	$ 20	$ 1,392

(a) As a result of our impairment assessment in 2015, we recorded the following significant impairment charges, including those reported in discontinued operations, for which the fair value measured for these properties at December 31, 2015 was estimated to be approximately $880 million :

- $2,308 million impairment charge related to natural gas-producing properties in the Piceance Basin, reported in discontinued operations. Significant assumptions in valuing these properties included estimated cash flows from a potential divestment.
- $26 million impairment charge on our unproved leasehold acreage in the Piceance Basin, reported in discontinued operations, as a result of the impairment of the producing properties in conjunction with a potential divestment.

(b) As a result of our impairment assessment in 2014, we recorded the following significant impairment charges, including those reflected in discontinued operations, for which the fair value measured for these properties at December 31, 2014 was estimated to be approximately $11 million :

- $11 million impairment charge related to natural gas-producing properties in the Green River Basin. Significant assumptions in valuing these properties included proved reserves quantities of more than 23.0 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $4.77 per Mcfe for natural gas (adjusted for locational differences), natural gas liquids and oil, and an after-tax discount rates of 9 percent and 11 percent .
- $9 million of impairment charges related to costs of acquired unproved reserves and other insignificant producing properties including $5 million of which is reflected in discontinued operations.

(c) As a result of our impairment assessment in 2013, we recorded the following significant impairment charges, including those reflected in discontinued operations, for which the fair value measured for these properties at December 31, 2013 was estimated to be approximately $365 million :

- $792 million impairment charge related to natural gas producing properties and an equity method investment in the Appalachian Basin. Significant assumptions in valuing these properties included proved reserves quantities of more than 299 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.60 per Mcfe for natural gas (adjusted for locational differences), and an after-tax discount rate of 11 percent .
- $317 million impairment charge on our unproved leasehold acreage in the Appalachian Basin as a result of the impairment of the producing properties. Significant assumptions included estimates of the value per acre based on our recent transactions and those transactions observed in the market.
- $107 million impairment charge related to natural gas producing properties in the Powder River Basin, reported in discontinued operations. Significant assumptions in valuing these properties included proved reserves quantities of more than 294 billion cubic feet of gas equivalent, forward weighted average prices averaging approximately $3.53 per Mcfe for natural gas (adjusted for locational differences), and an after-tax discount rate of 11 percent .
- $88 million impairment charge related to acquired unproved reserves in the Piceance Basin, reported in discontinued operations. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, expectation for market participant drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 13 percent and 15 percent for probable and possible reserves, respectively.
- $85 million impairment charge related to acquired unproved reserves in the Powder River Basin reported in discontinued operations. Significant assumptions in valuing these unproved reserves included evaluation of probable and possible reserves quantities, expectation for market participant drilling plans, forward natural gas (adjusted for locational differences) and natural gas liquids prices, and an after-tax discount rate of 15 percent and 18 percent for probable and possible reserves, respectively.

Note 15 . Derivatives and Concentration of Credit Risk

Energy Commodity Derivatives

Risk Management Activities

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

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

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

Derivatives related to production

The following table sets forth the derivative notional volumes of the net long (short) positions that are economic hedges of production volumes, which are included in our commodity derivatives portfolio as of December 31, 2015 .

Commodity	Period	Contract Type (a)	Location	Notional Volume (b)	Weighted Average Price (c)
Crude Oil					
Crude Oil	2016	Fixed Price Swaps	WTI	(27,549)	$ 61.70
Crude Oil	2016	Basis Swaps	Midland	(5,000)	$ (0.45)
Crude Oil	2016	Fixed Price Calls	WTI	(1,243)	$ 55.75
Crude Oil	2016	Swaptions	WTI	(1,257)	$ 57.15
Crude Oil	2017	Fixed Price Swaps	WTI	(9,304)	$ 61.66
Crude Oil	2017	Swaptions	WTI	(1,500)	$ 59.00
Natural Gas					
Natural Gas	2016	Fixed Price Swaps	Henry Hub	(213)	$ 3.79
Natural Gas	2016	Basis Swaps	NGPL	(5)	$ (0.23)
Natural Gas	2016	Basis Swaps	Permian	(33)	$ (0.17)
Natural Gas	2016	Basis Swaps	Rockies	(230)	$ (0.21)
Natural Gas	2016	Basis Swaps	San Juan	(100)	$ (0.18)
Natural Gas	2016	Basis Swaps	SoCal	(45)	$ (0.01)
Natural Gas	2017	Basis Swaps	Rockies	(50)	$ (0.21)
Natural Gas	2017	Basis Swaps	San Juan	(33)	$ (0.16)
Natural Gas	2017	Basis Swaps	SoCal	(10)	$ —
Natural Gas	2017	Fixed Price Calls	Henry Hub	(16)	$ 4.50
Natural Gas	2017	Swaptions	Henry Hub	(65)	$ 4.19
Natural Gas	2018	Fixed Price Calls	Henry Hub	(16)	$ 4.75

(a) Derivatives related to crude oil production are fixed price swaps settled on the business day average and swaptions. The derivatives related to natural gas production are fixed price swaps, basis swaps, calls, swaptions and costless collars. In connection with several natural gas and crude oil swaps entered into, we granted swaptions to the swap counterparties in exchange for receiving premium hedged prices on the natural gas and crude oil swaps. These swaptions and calls grant the counterparty the option to enter into future swaps with us.
(b) Crude oil volumes are reported in Bbl/day and natural gas volumes are reported in BBtu/day.
(c) The weighted average price for crude oil is reported in $/Bbl and the natural gas is reported in $/MMBtu.

Derivatives primarily related to transportation

The following table sets forth the derivative notional volumes of the net long (short) positions of derivatives primarily related to transportation contracts, which are included in our commodity derivatives portfolio as of December 31, 2015 . The weighted average price is not reported since the notional volumes represent a net position comprised of buys and sells with positive and negative transaction prices.

Commodity	Period	Contract Type (a)	Location (b)	Notional Volume (c)
Natural Gas	2016	Index	Multiple	(17)

(a) We enter into exchange traded fixed price and basis swaps, over-the-counter fixed price and basis swaps, physical fixed price transactions and transactions with an index component.
(b) We transact at multiple locations primarily around our core assets to maximize the economic value of our transportation

and asset management agreements.

(c) Natural gas volumes are reported in BBtu/day.

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.

	December 31,			
	2015		2014	
	Assets	Liabilities	Assets	Liabilities
	(Millions)			
Derivatives related to production not designated as hedging instruments	$ 359	$ 15	$ 503	$ 10
Derivatives related to physical marketing agreements not designated as hedging instruments	—	—	19	32
Total derivatives not designated as hedging instruments	$ 359	$ 15	$ 522	$ 42

For the periods ended December 31, 2015, 2014 and 2013, respectively, the Company had no energy commodity derivatives designated as cash flow hedges.

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

	Years Ended December 31,		
	2015	2014	2013
Gain (loss) from derivatives related to production not designated as hedging instruments(a)	$ 438	$ 515	$ (57)
Gain (loss) from derivatives related to physical marketing agreements not designated as hedging instruments(b)	(20)	(81)	(67)
Net gain (loss) on derivatives not designated as hedges	$ 418	$ 434	$ (124)

(a) Includes settlements totaling $650 million for the year ended December 31, 2015, and payments totaling $4 million and $11 million for the years ended December 31, 2014 and 2013, respectively.

(b) Includes payments totaling $33 million , $120 million and $6 million for the years ended December 31, 2015, 2014 and 2013, respectively.

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

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
December 31, 2015		(Millions)		
Derivative assets with right of offset or master netting agreements	$ 359	$ (14)	$ —	$ 345
Derivative liabilities with right of offset or master netting agreements	$ (15)	$ 14	$ —	$ (1)
December 31, 2014				
Derivative assets with right of offset or master netting agreements	$ 522	$ (25)	$ —	$ 497
Derivative liabilities with right of offset or master netting agreements	$ (42)	$ 25	$ 17	$ —

(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 S&P'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 December 31, 2015 , we didn't have any collateral posted to derivative counterparties, including zero initial margin to clearinghouses or exchanges to enter into positions or maintenance margin for changes in fair value of those positions, to support the aggregate fair value of our net $1 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which includes a reduction of less than $1 million to our liability balance for our own nonperformance risk. At December 31, 2014 , we had collateral totaling $26 million posted to derivative counterparties, which includes $9 million of initial margin to clearinghouses or exchanges to enter into positions and $17 million of maintenance margin for changes in fair value of those positions, to support the aggregate fair value of our net $17 million derivative liability position (reflecting master netting arrangements in place with certain counterparties), which included 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 less than $1 million at both December 31, 2015 and December 31, 2014 .

Concentration of Credit Risk

Cash equivalents

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

Accounts receivable

The following table summarizes concentration of receivables, net of allowances, by product or service as of December 31.

	2015	2014
	(Millions)	
Receivables by product or service:		
Sale of natural gas, crude and related products and services	$ 171	$ 339
Joint interest owners	90	88
Other	39	10
Total	$ 300	$ 437

Natural gas customers include pipelines, distribution companies, producers, marketers and industrial users primarily located in the eastern and northwestern United States, Rocky Mountains and North Dakota. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly.

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 creditworthy parties.

We also enter into master netting agreements to mitigate counterparty performance and credit risk. During 2015 , 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 following table summarizes the gross and net credit exposure from our derivative contracts as of December 31, 2015 .

Counterparty Type	Gross Total	Net Total
	(Millions)	
Financial institutions (Investment Grade)(a)	$ 360	$ 346
Credit reserves	(1)	(1)
Credit exposure from derivatives	$ 359	$ 345

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

Our seven largest net counterparty positions represent approximately 99 percent of our net credit exposure from derivatives and are all with investment grade counterparties. Under our marginless hedging agreements with key banks, neither party is required to provide collateral support related to hedging activities.

Other

At December 31, 2015 , we held collateral support of approximately $45 million , either in the form of cash, letters of credit or surety bond, related to our gas management sale agreements.

Collateral support for our commodity agreements include letters of credit and guarantees of payment by creditworthy parties.

Revenues

During 2015 , 2014 and 2013 , BP Energy Company accounted for 3 percent , 15 percent and 7 percent of our consolidated revenues, respectively. During 2015 , 2014 and 2013 , Western Refining accounted for 11 percent , 4 percent and 2 percent of our consolidated revenues, respectively. Management believes that the loss of any individual purchaser would not have a long-term material adverse impact on the financial position or results of operations of the Company.

Note 16. Subsequent Events

Transportation obligations

On May 25, 2016, WPX announced the signing of an agreement to buy out the remaining transportation obligations that supported its prior operating presence in the Piceance Basin for approximately $239 million . Upon closing, WPX will release all of its Piceance-related firm transportation capacity across four interstate pipeline systems to Citadel NGPE, LLC. The buyout also eliminates approximately $164 million in letters of credit and their associated annual interest expenses, and releases WPX from nearly $400 million in demand obligations from 2016 through 2032. WPX is using cash on-hand to fund the agreement. The parties expect to close the transaction in the third quarter, subject to regulatory approval and typical closing conditions.

Senior Notes

Subsequent to February 25, 2016, we redeemed an additional $87 million after we tendered for the remaining outstanding 5.250% senior notes due in 2017.

Credit Facility

On March 18, 2016, the Company entered into a Second Amended and Restated Credit Agreement with Wells Fargo Bank, National Association, as Administrative Agent, Lender and Swingline Lender and the other lenders party thereto (the “Credit Facility”). The Credit Facility, as amended, is now a $1.2 billion senior secured revolving credit facility with a maturity date of October 28, 2019 . The Credit Facility may be used for working capital, acquisitions, capital expenditures and other general corporate purposes. The financial covenants in the Credit Facility may limit our ability to borrow money, depending on the applicable financial metrics at any given time. As of May 25, 2016, we did not have any outstanding borrowings under the Credit Facility Agreement.

During any Collateral Trigger Period, loans under the Credit Facility will be subject to a Borrowing Base as calculated in accordance with the Provisions of the Credit Facility. As of March 18, 2016, the Borrowing Base was set at $1.025 billion . This Borrowing Base will remain in effect until the next Borrowing Base is re-determined pursuant to the Credit Facility. The next scheduled Re-determination date is October 1, 2016 and biannually thereafter.

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

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

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

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

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

During any Collateral Trigger Period, the Company is required to maintain a ratio of Consolidated Secured Indebtedness to Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) of not greater than 3.25 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2017 and 3.00 to 1.00 thereafter. During any Collateral Trigger Period, the Company may also not permit the ratio of consolidated current assets (including the unused amount of the Borrowing Base) of the Company and its consolidated subsidiaries to the consolidated current liabilities of the Company and its consolidated subsidiaries as of the last day of any fiscal quarter to be less than 1.0 to 1.0.

Other than during a Collateral Trigger Period, the Company is required to maintain a ratio of Consolidated Net Indebtedness to Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) of not greater than 4.50 to 1.00 as of the last day of any fiscal quarter ending on or before December 31, 2016 and 4.00 to 1.00 thereafter, unless at such time the Company's Corporate Ratings are equal to, or better than, Baa3 or BBB- by at least one of S&P and Moody's and not less than BB+ or Ba1 by the other such agency. In addition, other than during a Collateral Trigger Period, the ratio of Consolidated Indebtedness to Consolidated Total Capitalization is not permitted to be greater than 60 percent and is applicable for the life of the agreement. Furthermore, other than during a Collateral Trigger Period, the Company may not permit the ratio of Consolidated EBITDAX (for the most recently ended four consecutive fiscal quarters) to Consolidated Interest Charges to be less than 2.5 to 1.00.

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

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

Credit Ratings

As of the date of this filing, our credit ratings were as follows:

Standard and Poor's(a)	
Corporate Credit Rating	B+
Senior Unsecured Debt Rating	B
Outlook	Negative
Moody's Investors Service(b)	
LT Corporate Family Rating	B2
Senior Unsecured Debt Rating	B3
Outlook	Negative

WPX Energy, Inc.

QUARTERLY FINANCIAL DATA
(Unaudited)

Summarized quarterly financial data are as follows:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Millions, except per-share amounts)			
2015				
Revenues	$ 420	$ 154	$ 407	$ 385
Operating costs and expenses	$ 300	$ 251	$ 300	$ 294
Income (loss) from continuing operations	$ 52	$ 23	$ (70)	$ (9)
Income (loss) from discontinued operations	16	(53)	(160)	(1,525)
Net income (loss)	$ 68	$ (30)	$ (230)	$ (1,534)
Amounts attributable to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	$ 52	$ 23	$ (74)	$ (14)
Income (loss) from discontinued operations	15	(53)	(160)	(1,525)
Net income (loss)	$ 67	$ (30)	$ (234)	$ (1,539)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.26	$ 0.11	$ (0.29)	$ (0.06)
Income (loss) from discontinued operations	0.07	(0.25)	(0.64)	(5.53)
Net income (loss)	$ 0.33	$ (0.14)	$ (0.93)	$ (5.59)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ 0.25	$ 0.11	$ (0.29)	$ (0.06)
Income (loss) from discontinued operations	0.07	(0.25)	(0.64)	(5.53)
Net income (loss)	$ 0.32	$ (0.14)	$ (0.93)	$ (5.59)
2014				
Revenues	$ 602	$ 465	$ 538	$ 918
Operating costs and expenses	$ 545	$ 439	$ 362	$ 399
Income (loss) from continuing operations	$ (28)	$ (37)	$ 52	$ 269
Income (loss) from discontinued operations	47	(96)	14	(50)
Net income (loss)	$ 19	$ (133)	$ 66	$ 219
Amounts attributable to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	$ (28)	$ (37)	$ 52	$ 269
Income (loss) from discontinued operations	46	(98)	10	(50)
Net income (loss)	$ 18	$ (135)	$ 62	$ 219
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$ (0.14)	$ (0.18)	$ 0.26	$ 1.32
Income (loss) from discontinued operations	0.23	(0.48)	0.04	(0.24)
Net income (loss)	$ 0.09	$ (0.66)	$ 0.30	$ 1.08
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$ (0.14)	$ (0.18)	$ 0.26	$ 1.30
Income (loss) from discontinued operations	0.23	(0.48)	0.04	(0.24)
Net income (loss)	$ 0.09	$ (0.66)	$ 0.30	$ 1.06

The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to rounding.

Net income for first-quarter 2015 includes the following pre-tax items:

- $41 million gain related to our divestment of APCO (see Note 3).
- $69 million gain recorded for the sale of a portion of our Appalachian Basin operations (see Note 5).

- During 2015, we executed a termination and settlement agreement to release us from a crude oil transportation and sales agreement in anticipation of entering into a different agreement with another third party with more favorable terms. As a result of this contract termination and settlement, we recorded an expense of approximately $22 million which is included in other-net on the Consolidated Statements of Operations (see Note 5).

Net loss for second-quarter 2015 includes the following pre-tax item:

- $209 million gain recorded for the sale of a package of marketing contracts and release of certain related firm transportation capacity in the Northeast (see Note 5).

Net loss for third-quarter 2015 includes the following pre-tax items:

- We completed the acquisition of privately held RKI and incurred additional $104 million costs related to this (see Note 2).
- Discontinued operations had $187 million additional expense related to contract obligations as a result of the Powder River Basin sale closing (see Note 3).
- $47 million exploratory impairments comprised of dry hole costs, impairments of exploratory area well costs and impairments of leasehold costs primarily associated with exploratory plays for which management has decided to cease any further exploration activities.

Net loss for fourth-quarter 2015 includes the following pre-tax items:

- $2.3 billion of impairments costs on discontinued operation producing properties and leasehold (see Note 3).
- $70 million gain on sale of a North Dakota gathering system (see Note 5).
- $23 million related to gathering obligations in an area of the Appalachian Basin we exited in the fourth quarter of 2015 (see Note 5).

Net income for first-quarter 2014 includes the following item:

- $9 million deferred tax expense to accrue for the impact of new legislation (see Note 9 .)

Net loss for second-quarter 2014 includes the following pre-tax items:

- $195 million loss on the sale of a portion of our working interests in certain Piceance Basin wells, reported in discontinued operations (see Note 3).
- $40 million exploratory impairments comprised of dry hole costs, impairments of exploratory area well costs and impairments of leasehold costs primarily associated with exploratory plays for which management has decided to cease any further exploration activities.
- $11 million increase in gas management expense related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company.

Net income for third-quarter 2014 includes the following pre-tax item:

- $22 million exploratory impairments comprised of dry hole costs, impairments of exploratory area well costs and impairments of leasehold costs primarily associated with exploratory plays for which management has decided to cease any further exploration activities.

Net income for fourth-quarter 2014 includes the following pre-tax items:

- $87 million of impairments of costs of producing properties, acquired unproved reserves and leasehold (see Notes 3 and 5).
- During 2014, we assigned our remaining natural gas storage capacity agreement to a third party and sold the remaining natural gas stored under this agreement for a total loss of approximately $18 million reflected in gas management expenses in the Consolidated Statements of Operations.

We have significant continuing oil and gas producing activities primarily in the Permian Basin in Texas and New Mexico, the Williston Basin in North Dakota and the Piceance and San Juan Basins in the Rocky Mountain region, all of which are located in the United States. Until January 2015, we had international oil and gas producing activities, primarily in Argentina. The international activities through the date of the sale are reported as discontinued operations (see Note 3 of Notes to Consolidated Financial Statements). International net proved reserves, including amounts related to an equity method investment, were approximately 35 MMboe or less than 5 percent of our total domestic and international reserves at December 31, 2014. Other than noted below, the following information relates to our domestic oil and gas activities and excludes our gas management activities.

With the exception of Capitalized Costs and the Results of Operations for all years presented, the following information includes information of the Piceance Basin and information through the completion of the sale of the Powder River Basin, both of which have been reported as discontinued operations in our consolidated financial statements. Subsequent to December 31, 2015, we entered into an agreement for the sale of our Piceance Basin properties (see Note 3 of Notes to Consolidated Financial Statements). The Piceance Basin properties represent approximately 52 percent of our reserves. The Powder River Basin operations were sold in late 2015 and represented less than 5 percent of our total domestic proved reserves at December 31, 2014. Additionally, most of our Appalachian Basin assets were sold in early 2015 and also represented less than 5 percent of our total domestic proved reserves as of December 31, 2014.

Capitalized Costs

	As of December 31,	
	2015	2014
	(Millions)	
Proved Properties	$ 5,703	$ 4,192
Unproved properties	2,342	349
	8,045	4,541
Accumulated depreciation, depletion and amortization and valuation provisions	(1,763)	(1,292)
Net capitalized costs	$ 6,282	$ 3,249

- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $202 million and $109 million , net, for 2015 and 2014, respectively. The $109 million at December 31, 2014 includes costs related to gathering assets sold or held for sale in 2015.
- Proved properties include capitalized costs for oil and gas leaseholds holding proved reserves, development wells including uncompleted development well costs and successful exploratory wells.
- Unproved properties consist primarily of unproved leasehold costs.

Cost Incurred

	For the years ended December 31,		
	2015	2014	2013
	(Millions)		
Acquisition	$ 3,208	$ 294	$ 57
Exploration	84	92	104
Development	657	1,376	939
	$ 3,949	$ 1,762	$ 1,100

- Costs incurred include capitalized and expensed items.
- Acquisition costs are as follows: costs in 2015 primarily relate to the allocated purchase price of RKI properties in the Permian-Delaware Basin (see Note 2 of Notes to Consolidated Financial Statements) and includes 53 MMboe of proved developed reserves. Costs in 2014 primarily relate to purchases of oil acreage in the San Juan Basin and include approximately 5 MMboe of proved reserves. The 2013 costs are primarily for undeveloped leasehold in exploratory areas targeting oil reserves.
- Exploration costs include the costs incurred for geological and geophysical activity, drilling and equipping exploratory wells, including costs incurred during the year for wells determined to be dry holes, exploratory lease acquisitions and retaining undeveloped leaseholds. The 2015 amount primarily related to the drilling of Piceance Niobrara wells.

- Development costs include costs incurred to gain access to and prepare well locations for drilling and to drill and equip wells in our development basins. Development costs associated with our Piceance Basin operations were $106 million , $430 million and $284 million for 2015, 2014 and 2013, respectively.

Results of Operations

	For the years ended December 31,		
	2015	2014	2013
	(Millions)		
Revenues:			
Oil sales	$ 494	$ 669	$ 475
Natural gas sales	138	282	259
Natural gas liquid sales	23	20	10
Net gain (loss) on derivatives not designated as hedges	438	515	(57)
Other revenues	7	8	3
Total revenues	1,100	1,494	690
Costs:			
Lease and facility operating	145	143	109
Gathering, processing and transportation	64	71	73
Taxes other than income	62	88	68
Exploration	85	101	417
Depreciation, depletion and amortization	528	363	354
Impairment of certain proved properties	—	15	772
Impairment of costs of acquired unproved reserves	—	—	—
Net (gain) loss on sales of assets	(349)	—	—
General and administrative	203	217	211
Acquisition costs	23	—	—
Other (income) expense	63	13	12
Total costs	824	1,011	2,016
Results of operations	276	483	(1,326)
Provision (benefit) for income taxes	101	176	(484)
Exploration and production net income (loss)	$ 175	$ 307	$ (842)

- Amounts for all years exclude the equity losses from our equity method investees. Net equity losses from these investees were $1 million and $21 million in 2014 and 2013 , respectively.
- Other revenues consist of activities that are an indirect part of the producing activities.
- Exploration expenses include the costs of geological and geophysical activity, drilling and equipping exploratory wells determined to be dry holes and the cost of retaining undeveloped leaseholds including lease amortization and impairments. Additionally, exploration costs in 2015 and 2014 include impairments of certain exploratory well costs (see Note 5 of Notes to Consolidated Financial Statements). Exploration costs in 2013 include a $317 million impairment to estimated fair value of unproved leasehold costs in the Appalachian Basin.
- Depreciation, depletion and amortization includes depreciation of support equipment.
- Other income (expense) includes $22 million as a result of a termination of a crude oil transportation and sales agreement. Also included is a $23 million charge related to the net present value of future obligations under a gathering agreement in an Appalachian area for which we plugged and abandoned our remaining wells in December 2015.

Proved Reserves

The SEC defines proved oil and gas reserves (Rule 4-10(a) of Regulation S-X) as those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved reserves consist of two categories, proved developed reserves and proved undeveloped reserves. Proved developed reserves are currently producing wells and wells awaiting minor sales connection expenditure, recompletion, additional perforations or borehole stimulation treatments. Proved undeveloped reserves are those reserves which are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Proved reserves on undrilled acreage are generally limited to those that can be developed within five years according to planned drilling activity. Proved reserves on undrilled acreage also can include locations that are more than one offset away from current producing wells where there is a reasonable certainty of production when drilled or where it can be demonstrated with reasonable certainty that there is continuity of production from the existing productive formation.

The following is a summary of changes in our domestic proved reserves including proved reserves in the Powder River Basin which is reported as discontinued operations. Excluded from the table are our international reserves that are primarily attributable to a consolidated subsidiary (Apco) which represented less than 5 percent of our total reserves. The international interests were sold in January 2015. In addition, the table includes proved reserves in the Piceance Basin. As of December 31, 2015, proved developed reserves and proved undeveloped reserves in the Piceance Basin were 228 MMboe and 75 MMboe, respectively.

	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	All Products (MMBoe)
Proved reserves at December 31, 2012	**76.5**	**3,369.1**	**110.4**	**748.4**
Revisions	3.5	308.3	(25.4)	29.5
Divestitures	—	(0.2)	—	—
Extensions and discoveries	28.8	312.0	8.1	88.9
Production	(5.9)	(359.4)	(7.4)	(73.2)
Proved reserves at December 31, 2013	**102.9**	**3,629.8**	**85.7**	**793.6**
Revisions	(7.7)	(198.3)	(13.4)	(54.1)
Purchases	4.2	6.0	0.8	6.0
Divestitures	(1.8)	(314.6)	(8.5)	(62.7)
Extensions and discoveries	42.4	362.1	12.5	115.2
Production	(9.2)	(335.4)	(6.3)	(71.4)
Proved reserves at December 31, 2014	**130.8**	**3,149.6**	**70.8**	**726.6**
Revisions	(31.9)	(624.6)	(14.0)	(150.0)
Purchases	39.8	205.6	20.7	94.7
Divestitures	—	(380.3)	—	(63.4)
Extensions and discoveries	17.1	116.9	5.1	41.6
Production	(13.1)	(277.0)	(7.3)	(66.5)
Proved reserves at December 31, 2015	**142.7**	**2,190.2**	**75.3**	**583.0**
Proved developed reserves:				
December 31, 2013	**36.8**	**2,265.2**	**48.6**	**463.0**
December 31, 2014	**60.0**	**2,090.0**	**43.9**	**452.3**
December 31, 2015	**83.0**	**1,618.2**	**49.5**	**402.2**
Proved undeveloped reserves:				
December 31, 2013	**66.1**	**1,364.6**	**37.1**	**330.6**
December 31, 2014	**70.8**	**1,059.6**	**26.9**	**274.3**
December 31, 2015	**59.7**	**572.0**	**25.8**	**180.8**

- Natural gas reserves are computed at 14.73 pounds per square inch absolute and 60 degrees Fahrenheit .
- Revision in 2015 primarily reflect 209 MMboe of negative revisions related to the decrease in the 12 month average prices partially offset by 59 MMboe of positive revisions due to decreased costs and well improvements. The 2015 revisions comprised 108 MMboe net negative revisions related to proved undeveloped locations and 42 MMboe net negative revisions related to proved developed locations. Revisions in 2014 primarily reflect 16 MMboe of net positive revisions to developed reserves and 70 MMboe of net negative revisions to undeveloped reserves. The 70 MMboe of net negative revisions were primarily due to a reduction in near-term drilling capital estimates and the related limitations imposed by the SEC five year rules. Revisions in 2013 reflects 22 MMboe related to developed reserves and 7 MMboe related to undeveloped reserves.
- Purchases reflects the RKI acquisition of which 53.4 MMboe is proved developed and 41.3 MMboe is associated with proved undeveloped locations.
- Divestitures in 2015 relate to sales of properties in the Powder River Basin (28 MMboe) and the Appalachian Basin (35 MMboe). Divestitures in 2014 primarily relate to the sale of working interests in the Piceance Basin (see Notes 3 and 5 of Notes to Consolidated Financial Statements).
- Extensions and discoveries in 2015 reflect 20.9 MMboe added for proved developed locations and 20.7 MMboe for proved undeveloped locations primarily related to our San Juan Gallup and Williston Basins. Extensions and discoveries in 2014 reflect 31 MMboe added for drilled locations and 84 MMboe added for new proved undeveloped locations. Extensions and discoveries in 2013 reflects 21 MMboe added for drilled locations and 68 MMboe added for

new undeveloped locations. The 2014 and 2013 extensions and discoveries were primarily in the Piceance Basin, Williston Basin, Appalachian Basin and San Juan Basin.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is based on the estimated quantities of proved reserves. Prices are based on the 12-month average price computed as an unweighted arithmetic average of the price as of the first day of each month, unless prices are defined by contractual arrangements. For the years ended December 31, 2015, 2014 and 2013, the average domestic combined natural gas and NGL equivalent price was $2.32 , $4.34 and $3.63 per Mcfe, respectively. The average domestic oil price used in the estimates for the years ended December 31, 2015, 2014 and 2013 was $43.84 , $83.62 and $92.16 per barrel, respectively. Future income tax expenses have been computed considering applicable taxable cash flows and appropriate statutory tax rates. The discount rate of 10 percent is as prescribed by authoritative guidance. Continuation of year-end economic conditions also is assumed. The calculation is based on estimates of proved reserves, which are revised over time as new data becomes available. Probable or possible reserves, which may become proved in the future, are not considered. The calculation also requires assumptions as to the timing of future production of proved reserves, and the timing and amount of future development and production costs.

Numerous uncertainties are inherent in estimating volumes and the value of proved reserves and in projecting future production rates and timing of development expenditures. Such reserve estimates are subject to change as additional information becomes available. The reserves actually recovered and the timing of production may be substantially different from the reserve estimates.

Standardized Measure of Discounted Future Net Cash Flows

	As of December 31,	
	2015	**2014**
	(Millions)	
Future cash inflows	$ 12,391	$ 26,444
Less:		
Future production costs	7,757	12,641
Future development costs	1,761	3,426
Future income tax provisions	—	2,519
Future net cash flows	2,873	7,858
Less 10 percent annual discount for estimated timing of cash flows	1,589	3,975
Standardized measure of discounted future net cash inflows	$ 1,284	$ 3,883

- Our historical tax basis (i.e. future deductions for taxable income calculation) of proved properties at December 31, 2015 is greater than the total future net cash flows before taxes; therefore, future taxable income would be less than zero.
- Included in the $1,284 million of discounted future net cash inflows is $270 million related to the properties in the Piceance Basin.

Sources of Change in Standardized Measure of Discounted Future Net Cash Flows

	For the years ended December 31,		
	2015	2014	2013
		(Millions)	
Beginning of year	**$ 3,883**	**$ 2,964**	**$ 1,949**
Sales of oil and gas produced, net of operating costs	(541)	(1,324)	(1,040)
Net change in prices and production costs	(5,231)	303	1,198
Extensions, discoveries and improved recovery, less estimated future costs	254	1,761	1,282
Development costs incurred during year	276	592	414
Changes in estimated future development costs	1,213	143	(736)
Purchase of reserves in place, less estimated future costs	657	147	—
Sale of reserves in place, less estimated future costs	(397)	(391)	(3)
Revisions of previous quantity estimates	(374)	(536)	239
Accretion of discount	489	383	225
Net change in income taxes	1,073	(142)	(540)
Other	(18)	(17)	(24)
Net changes	(2,599)	919	1,015
End of year	**$ 1,284**	**$ 3,883**	**$ 2,964**

WPX Energy, Inc.

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

	Beginning Balance	Charged (Credited) to Costs and Expenses	Other	Deductions	Ending Balance
2015:					
Allowance for doubtful accounts—accounts and notes receivable(a)	$ 6	$ 5	$ —	$ (5)	$ 6
Deferred tax asset valuation allowance(b)	118	3	3	—	124
Price-risk management credit reserves—assets(a)(c)	1	—	—	—	1
2014:					
Allowance for doubtful accounts—accounts and notes receivable(a)	$ 7	$ —	$ —	$ (1)	$ 6
Deferred tax asset valuation allowance(b)	102	(1)	17	—	118
Price-risk management credit reserves—assets(a)(c)	—	—	1	—	1
2013:					
Allowance for doubtful accounts—accounts and notes receivable(a)	$ 11	$ (3)	$ —	$ (1)	$ 7
Deferred tax asset valuation allowance(b)	19	80	3	—	102

(a) Deducted from related assets.
(b) Deducted from related assets, with a portion included in assets held for sale.
(c) Included in revenues.