WPX ENERGY, INC.
Form 10-K
February 25, 2016

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

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

For the fiscal year ended December 31, 2015
OR

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

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

Delaware (State or Other Jurisdiction of Incorporation or Organization)	45-1836028 (IRS Employer Identification No.)
3500 One Williams Center, Tulsa, Oklahoma (Address of Principal Executive Offices)	74172-0172 (Zip Code)

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $0.01 par value	New York Stock Exchange
6.25% Series A Mandatory Convertible Preferred Stock, $0.01 par value	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No þ

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ

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

Large accelerated filer	þ	Accelerated filer	¨
Non-accelerated filer	¨ (Do not check if a smaller reporting company)	Smaller reporting company	¨

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant’s most recently completed second quarter was approximately $2,506,843,707.

The number of shares outstanding of the registrant’s common stock outstanding at February 24, 2016 was 275,484,692.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s definitive Proxy Statement to be delivered to stockholders in connection with its 2016 Annual Meeting of Stockholders are incorporated by reference into Part III.

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CERTAIN DEFINITIONS

The following oil and gas measurements and industry and other terms are used in this Form 10-K. As used herein, production volumes represent sales volumes, unless otherwise indicated.

Barrel—means one barrel of petroleum products that equals 42 U.S. gallons.

BBtu/d—means one billion BTUs per day.

Bcfe—means one billion cubic feet of gas equivalent determined using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

British Thermal Unit or BTU—means a unit of energy needed to raise the temperature of one pound of water by one degree Fahrenheit.

FERC—means the Federal Energy Regulatory Commission.

Fractionation—means the process by which a mixed stream of natural gas liquids is separated into its constituent products, such as ethane, propane and butane.

LOE—means lease and other operating expense excluding production taxes, ad valorem taxes and gathering, processing and transportation fees.

Mbbls—means one thousand barrels.

Mbbls/d—means one thousand barrels per day.

Mboe—means one thousand barrels of oil equivalent.

Mboe/d—means one thousand barrels of oil equivalent per day.

Mcf—means one thousand cubic feet.

Mcfe—means one thousand cubic feet of gas equivalent using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

MMbbls—means one million barrels.

MMboe—means one million barrels of oil equivalent.

MMBtu—means one million BTUs.

MMBtu/d—means one million BTUs per day.

MMcf—means one million cubic feet.

MMcf/d—means one million cubic feet per day.

MMcfe—means one million cubic feet of gas equivalent using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

MMcfe/d—means one million cubic feet of gas equivalent per day using the ratio of one barrel of oil, condensate or NGLs to six thousand cubic feet of natural gas.

NGL—means natural gas liquids; natural gas liquids result from natural gas processing and crude oil refining and are used as petrochemical feedstocks, heating fuels and gasoline additives, among other applications.

PART I

In this report, WPX (which includes WPX Energy, Inc. and, unless the context otherwise requires, all of our subsidiaries) is at times referred to in the first person as “we,” “us” or “our.” We also sometimes refer to WPX as the “Company” or “WPX Energy.”

Throughout this report we “incorporate by reference” certain information in parts of other documents filed with the Securities and Exchange Commission (the “SEC”). The SEC allows us to disclose important information by referring to it in that manner. Please refer to such documents for information.

We are making forward-looking statements in this report. In “Item 1A: Risk Factors” we discuss some of the risk factors that could cause actual results to differ materially from those stated in the forward-looking statements.

Item 1. Business

WPX ENERGY, INC.

Incorporated in 2011, 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 have built a geographically diverse portfolio of natural gas and oil reserves through organic development and strategic acquisitions. Our proved reserves at December 31, 2015 were 583 MMboe which includes 304 MMboe related to the Piceance Basin which is subject to a divestiture process. Our reserves reflect a mix of 24 percent crude oil, 63 percent natural gas and 13 percent NGLs. During 2015, our reserve additions did not fully replace our production for all commodities.

Our principal areas of operation are the Permian Basin in Texas and New Mexico, the Williston Basin in North Dakota, and the San Juan Basin in New Mexico and Colorado. Our principal executive office is located at 3500 One Williams Center, Tulsa, Oklahoma 74172. Our telephone number is 855-979-2012. We maintain an Internet site at www.wpxenergy.com.

BUSINESS OVERVIEW AND PROPERTIES

Our Business Strategy

Our business strategy is to increase shareholder value by increasing production over time of oil, natural gas, and NGLs, expanding our margins, and finding and developing reserves.

- Focused, Long-Term Portfolio Management. We are focused on long-term profitable growth. Our objective over time is to grow our production within our cash flow. With that in mind, we continuously evaluate the performance of our assets and, when appropriate, we consider divestitures of assets that are underperforming or which are no longer a part of our strategic focus. Since mid-2014, we completed or announced approximately $5.5 billion of asset divestitures, allowing us to focus on our core areas and strengthen our financial position.With regard to our core assets we expect to allocate capital to the most profitable opportunities based on commodity price cycles and other market conditions, enabling us to grow our reserves and production in a manner that maximizes our returns on investments.
- Build Asset Scale. We expect to opportunistically acquire acreage positions in areas where we feel we can establish significant scale and replicate cost-efficient development practices. We may also consider other “bolt-on” transactions that are directed at driving operational efficiencies through increased scale. We can manage costs by focusing on the establishment of large scale, contiguous acreage blocks where we can operate a majority of the properties. We believe this strategy allows us to better achieve economies of scale and apply continuous technological improvements in our operations. We have a history of acquiring undeveloped properties that meet our expected return requirements and other acquisition criteria to expand upon our existing positions as well as acquiring undeveloped acreage in new geographic areas that offer significant resource potential.
- Margin Expansion thru Focus on Costs. We believe we can expand our margins by focusing on opportunities to reduce our cost structure. As we rationalize our portfolio and reduce our areas of focus to core basins, we have the opportunity to improve our cost structure and ensure that our organization is in alignment with our margin growth objectives.
- Continue Oil Development and Increase Optionality. We believe that efforts to develop our oil properties will yield a more balanced commodity mix in our production, providing us with the option of focusing on the commodity with the best returns under different market conditions. This optionality, we believe, will place us in a position where we can better protect and grow our cash flows. We have engaged and will continue to engage in commodity derivative hedging activities to maintain a degree of cash flow stability. Typically, we target hedging approximately 50 percent of expected revenue from domestic production during a current calendar year in order to strike an appropriate balance of commodity price upside with cash flow protection, although we may vary from this level based on our perceptions of market risk. We have hedged approximately three-fourths of anticipated 2016 oil production at a weighted average price of $60.85 per barrel, excluding the derivatives anticipated to be assigned to the Piceance Buyer at closing, we have natural gas derivatives totaling 213,604 MMBtu per day for 2016, at a weighted average price of $3.79 per MMBtu.
- Maintain Financial Flexibility. We believe that expected asset sales will allow us to decrease our current levels of near-term long-term debt and provide additional liquidity. In addition, our continued focus on cost reductions, increased capital efficiency and long-term oil production growth will allow us to generate increased and sustainable annual cash flows from operations. This cash flow, combined with our capital structure and available sources of liquidity, will allow us to efficiently develop and grow our resource base and pursue reserve growth throughout a variety of commodity price environments.

Significant Properties

Our principal areas of operation are the Permian Basin, Williston Basin and San Juan Basin. On February 9, 2016, we announced an agreement to sell our operations in the Piceance Basin in Colorado for approximately $910 million. We expect the sale of our Piceance Basin operations to close in the second quarter of 2016.

Permian Basin

We entered the Permian Basin in August 2015 upon the closing of our acquisition of RKI Exploration & Production, LLC (“RKI”) (the “Acquisition”). We operate 699 wells in the Permian Basin and also own interests in 962 wells operated by others. We hold approximately 94,000 net acres in the Permian Basin, and more specifically in the Delaware Basin sub-area, with core operations located in Eddy, Lea and Chaves Counties in New Mexico and Loving, Pecos, Reeves, Ward and Winkler Counties in Texas. Approximately 98% of the leasehold is held by production. The Permian Basin is one of the most prolific hydrocarbon producing regions of the United States and spans an area approximately 250 miles wide by 300 miles long. The basin is characterized by numerous stacked reservoirs, high oil and natural gas content, extensive production history, long-lived reserves and high drilling success rates.

Since our acquisition of RKI, we have operated an average of 4 drilling rigs in the Delaware Basin and have had an average of 17.4 Mboe per day of net production. In response to lower commodity prices, we expect to operate 2 rigs in the Delaware Basin in 2016. Capital expenditures, excluding land purchases, since the Acquisition were approximately $99 million, which included completion of 20 gross (14) net wells. As of December 31, 2015, another 6 gross operated wells were awaiting completion.

Our activity in the Delaware Basin is primarily focused on the Bone Spring interval (which includes the Avalon sand and shales, and the Bone Springs sands, shales and carbonates), the shallower Delaware sand interval, and the Wolfcamp Shale formation. We have a multi-year inventory of stacked plays on 94,000 net acres.

RKI historically maintained a strong commitment to developing the necessary midstream and operational infrastructure to support drilling activities and keep pace with production growth, including investing in low and high pressure gathering lines, compression systems, electrical power supply systems, fresh water supply systems and saltwater disposal systems. This gathering system has 192 miles of active pipeline and four operated compressor stations capable with 90 MMcf per day of gas compression capacity. This infrastructure also includes a produced water disposal system with 174 miles of pipeline across two states and 39 active disposal wells capable of disposing 200,000 barrels per day. Other midstream assets include 16 miles of active fresh water transfer pipeline. These midstream assets provide a competitive advantage and reduce reliance on third parties for takeaway capacity.

Williston Basin

In December 2010, we acquired leasehold positions of approximately 85,800 net acres in the Williston Basin. All of these properties are on the Fort Berthold Indian Reservation in North Dakota and we are the primary operator. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results as well as the publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken and Three Forks formations, the primary targets for all of the well locations in our current drilling inventory. We operate 204 wells in the Williston Basin and also own interest in 72 wells operated by others. We hold 84,735 net acres in the Williston Basin.

During 2015, we operated an average of 1.4 rigs on our Williston Basin properties and we had an average of 25.7 Mboe per day of net production from our Williston Basin wells. In response to lower oil prices, we expect to operate 1 rig in the Williston Basin in 2016. Capital expenditures were approximately $213 million which included the completion of 34 gross (21 net) wells in 2015. As of December 31, 2015, another 17 gross operated wells were awaiting completion.

We are developing oil reserves through horizontal drilling in the Middle Bakken and the Upper Three Forks Shale oil formations. Based on our subsurface geological analysis, we believe that our position lies in an area of the basin with substantial potential recovery for Bakken and Three Forks formation oil.

Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada, covering approximately 202,000 square miles, of which 143,000 square miles are in the United States. The basin produces oil and natural gas from numerous producing horizons including the Bakken, Three Forks, Madison and Red River formations.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members referred to as the Upper, Middle and Lower Bakken Shales. The formation ranges up to 150 feet thick and is a continuous and structurally simple reservoir. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The Middle Bakken, which varies in composition from a silty dolomite to shaly limestone or sand, serves as the productive formation and is a critical reservoir for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as the Sanish Sand. The Three Forks formation is an unconventional carbonate play. Similar to the Bakken formation, the Three Forks formation is being exploited utilizing the same horizontal drilling and advanced completion techniques as the Bakken development. Drilling in the Three Forks formation began in mid-2008 and many operators are drilling wells targeting this formation.

Our acreage in the Williston Basin is leased to us by or with the approval of the federal government or its agencies, and is subject to federal authority, the National Environmental Policy Act (“NEPA”), the Bureau of Indian Affairs or other regulatory regimes that require governmental agencies to evaluate the potential environmental impacts of a proposed project on government owned lands. These regulatory regimes impose obligations on the federal government and governmental agencies

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that may result in legal challenges and potentially lengthy delays in obtaining project permits or approvals and could result, in certain instances, in the cancellation of existing leases.

San Juan Basin

In 2013, we announced a successful oil discovery in the Mancos Gallup Sandstone in the San Juan Basin that has the potential to significantly increase our oil production and reserves in future years. In 2014, we announced that we executed multiple transactions to own or control over 53,000 additional acres in the heart of the San Juan Basin's Gallup oil window. At December 31, 2015, our leasehold position in the oil window of the San Juan Basin was approximately 96,000 net acres of which we own or control, and we are targeting additional acreage.

Our San Juan Basin properties also include holdings across the basin producing primarily from the Mesaverde, Fruitland Coal and Mancos Shale formations which are predominantly gas bearing. We operate four units in New Mexico (Rosa, Cox Canyon, Northwest Lybrook and South Chaco) and also operate the Northeast Chaco CA (Communitized Area), as well as a number of non-unit properties. We operate in three major areas of Colorado (Northwest Cedar Hills, Ignacio and Bondad). We operate 991 wells in the San Juan Basin and also own interest in 2,322 wells operated by other operators in New Mexico and Colorado. We hold approximately 130,000 net acres in the gas window of the basin.

During 2015, we operated an average of 1.5 rigs in the San Juan Basin on our oil properties and in response to lower oil prices we expect to operate 1 rig in the San Juan Basin in 2016. We had an average of 33.8 Mboe per day of net production from our San Juan Basin properties which included 8.9 Mbbls per day of oil. Capital expenditures were approximately $286 million which included the completion of 58 gross (51 net) wells. As of December 31, 2015, another 5 gross operated wells were awaiting completion.

The San Juan Basin is one of the oldest and most prolific coal bed methane plays in the world. The Fruitland coal bed extends to depths of approximately 4,200 feet with net thickness ranging from zero to 100 feet. The Mesaverde play is the top producing tight gas play in the basin with total thickness ranging from 500 to 2,500 feet. The Mesaverde is underlain by the upper Mancos Shale and overlain by the Lewis Shale. The Mancos Shale, locally referred to as the Gallup Sandstone, is found at a depth of approximately 5,400 feet and is fine-grained sandstone interval of approximately 150 feet thick. The Mancos Shale includes both oil and natural gas.

Some of our acreage in the San Juan Basin is leased to us by or with the approval of the federal government or its agencies, including the United States Forest Service, Bureau of Land Management ("BLM"), the Bureau of Indian Affairs, and the Federal Indian Minerals Office. These particular leases are subject to federal authority, including the National Environmental Policy Act, and require governmental agencies to evaluate the potential environmental impacts of a proposed project on government owned lands. These regulatory regimes impose obligations on the federal government and governmental agencies that may result in legal challenges and potentially lengthy delays in obtaining both permits to drill and rights of way.

Other Properties

We also have extensive operations in the Piceance Basin of Colorado. However, as previously noted, on February 9, 2016, we announced an agreement to sell our operations in the Piceance Basin in Colorado for approximately $910 million. We expect the sale of our Piceance Basin operations to close in the second quarter of 2016.

During 2015, we had an average 97.6 Mboe per day of net production from our Piceance Basin wells. Capital expenditures in the Piceance Basin were approximately $177 million which included the completion of 73 gross (71 net) wells in 2015.

Acquisitions and Divestitures

In 2015, we announced or completed acquisitions and divestitures having an aggregate value of more than $4.1 billion. These acquisitions and divestitures included the following material transactions:

- Apco Disposition. In January 2015, we completed the disposition of our international interests upon the successful merger of Apco Oil and Gas International Inc. ("Apco") with a subsidiary of privately held Pluspetrol Resources Corporation. We received approximately $294 million for the disposition of our 69 percent controlling equity interest in Apco.

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RKI Acquisition. In August 2015, we completed the acquisition of privately held RKI. Per the terms of the merger agreement, the purchase price was $2.75 billion, consisting of 40 million unregistered shares of WPX common stock and approximately $2.28 billion in cash. The cash consideration was subject to closing adjustments and was reduced by our assumption of $400 million aggregate principal amount of RKI's senior notes and amounts outstanding under RKI's revolving credit facility along with other working capital items.

As previously noted, we signed an agreement on February 9, 2016 to sell our wholly owned subsidiary WPX Energy Rocky Mountain LLC, to Terra Energy Partners LLC ("Terra"), for $910 million. WPX Energy Rocky Mountain LLC holds our Piceance Basin operations. The agreement requires Terra to assume 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. The parties expect to close the sale in the second quarter of 2016.

Title to Properties

Our title to properties is subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the natural gas and oil industry, to liens for current taxes not yet due and to other encumbrances. In addition, leases on Native American reservations are subject to Bureau of Indian Affairs and other approvals unique to those locations. As is customary in the industry in the case of undeveloped properties, a limited investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time which can result in litigation and delay or loss of our ability to realize the benefits of our leases.

Reserves and Production Information

We have significant oil and gas producing activities primarily in the Permian, Piceance, Williston and San Juan Basins located in the United States. As previously noted, on February 9, 2016, we entered into an agreement to sell our operations in the Piceance Basin.

Oil and Gas Reserves

The following table sets forth our estimated net proved developed and undeveloped reserves expressed by product and on an oil equivalent basis for the reporting periods December 31, 2015, 2014 and 2013.

	As of December 31, 2015				
	Oil (Mbbls)	Gas (MMcf)	NGL (Mbbls)	Equivalent (Mboe)	%
Proved Developed	83,009	1,618,254	49,527	402,245	69%
Proved Undeveloped	59,710	571,949	25,766	180,801	31%
Total Proved(a)	142,719	2,190,203	75,293	583,046	
	As of December 31, 2014				
	Oil (Mbbls)	Gas (MMcf)	NGL (Mbbls)	Equivalent (Mboe)	%
Proved Developed	60,012	2,089,974	43,955	452,296	62%
Proved Undeveloped	70,817	1,059,617	26,885	274,305	38%
Total Proved(a)	130,829	3,149,591	70,840	726,601	
	As of December 31, 2013				
	Oil (Mbbls)	Gas (MMcf)	NGL (Mbbls)	Equivalent (Mboe)	%
Proved Developed	36,828	2,265,204	48,587	462,949	58%
Proved Undeveloped	66,102	1,364,552	37,128	330,655	42%
Total Proved(a)	102,930	3,629,756	85,715	793,604	

(a) Total Proved Reserves for the Piceance Basin were 303,748 Mboe, 422,425 Mboe and 503,119 Mboe as of December 31, 2015, 2014 and 2013, respectively.

The following table sets forth our estimated net proved reserves for our largest areas of activity expressed by product and on an oil equivalent basis as of December 31, 2015.

	As of December 31, 2015			
	Oil (Mbbls)	Gas (MMcf)	NGL (Mbbls)	Equivalent (Mboe)
Permian Basin	38,475	201,416	20,248	92,292
Williston Basin	78,512	43,429	7,335	93,085
San Juan Basin	19,923	349,589	8,033	86,221
Piceance Basin	5,707	1,551,734	39,418	303,748
Appalachia Basin	—	32,023	—	5,337
Other	102	12,012	259	2,363
Total Proved	142,719	2,190,203	75,293	583,046

We prepare our own reserves estimates and approximately 99 percent of our reserves are audited by Netherland, Sewell & Associates, Inc. (“NSAI”).

We have not filed on a recurring basis estimates of our total proved net oil, NGL, and gas reserves with any U.S. regulatory authority or agency other than with the U.S. Department of Energy and the SEC. The estimates furnished to the Department of Energy have been consistent with those furnished to the SEC.

Our 2015 year-end estimated proved reserves reflect an average oil price of $43.84 per barrel, an average natural gas price of $2.26 per Mcf and average NGL price of $15.84 per barrel. These prices were calculated from the 12-month trailing average, first-of-the-month price for the applicable indices for each basin as adjusted for respective location price differentials. During 2015, we added 41.6 MMboe of extensions and discoveries to our proved reserves. During 2015, we incurred $717 million in expenditures (both development and certain exploratory) which included the drilling of 190 gross (136 net) wells.

Proved reserves reconciliation

The 42 MMboe of extensions and discoveries reflects 21 MMboe added for drilled locations and 21 MMboe added for new proved undeveloped locations. The extensions and discoveries were primarily in the Williston and San Juan Basins. The acquisitions of 95 MMboe were in the Permian Basin. The overall net negative revisions of 150 MMboe reflect 42 MMboe of net negative revisions made to developed reserves and 108 MMboe of net negative revisions made to undeveloped reserves. In addition, the 150 MMboe of net negative revisions reflect 209 MMboe in negative revisions due to the decrease in the 12 month average prices partially offset by 59 MMboe of positive revisions due to decreased costs and improved well economics.

Reserves estimation process

Our reserves are estimated by deterministic methods using an appropriate combination of production performance analysis and volumetric techniques. The proved reserves for economic undrilled locations are estimated by analogy or volumetrically from offset developed locations. Reservoir continuity and lateral pervasiveness of our tight-sands, shale and coal bed methane reservoirs is established by combinations of subsurface analysis and analysis of 2D and 3D seismic data and pressure data. Understanding reservoir quality may be augmented by core samples analysis.

The engineering staff of each basin asset team provides the reserves modeling and forecasts for their respective areas. Various departments also participate in the preparation of the year-end reserves estimate by providing supporting information such as pricing, capital costs, expenses, ownership, gas gathering and gas quality. The departments and their roles in the year-end reserves process are coordinated by our corporate reserves department. The corporate reserves department's responsibilities also include performing an internal review of reserves data for reasonableness and accuracy, working with NSAI and the asset teams to successfully complete the reserves audit, finalizing the year-end reserves report and reporting reserves data to accounting.

The preparation of our year-end reserves report is a formal process. Early in the year, we begin with a review of the existing internal processes and controls to identify where improvements can be made from the prior year's reporting cycle. Later in the year, the reserves staffs from the asset teams submit their preliminary reserves data to the corporate reserves department. After review by the corporate reserves department, the data is submitted to NSAI to begin their audits. Reserves data analysis and further review are then conducted and iterated between the asset teams, corporate reserves department and NSAI. In early December, reserves are reviewed with senior management. The process concludes upon receipt of the audit letter from NSAI.

The reserves estimates resulting from our process are subjected to both internal and external controls to promote transparency and accuracy of the year-end reserves estimates. Our internal corporate reserves department is independent and does not work within an asset team or report directly to anyone on an asset team. The corporate reserves department provides detailed independent review and extensive documentation of the year-end process. Our internal processes and controls, as they relate to the year-end reserves, are reviewed and updated as appropriate. The compensation of our corporate reserves department is not directly linked to reserves additions or revisions except to the extent that reserves additions are a component of our all-employee incentive plan.

Approximately 99 percent of our total year-end 2015 domestic proved reserves estimates were audited by NSAI. When compared on a well-by-well basis, some of our estimates are greater and some are less than the NSAI estimates. NSAI is satisfied with our methods and procedures used to prepare the December 31, 2015 reserves estimates and future revenue, and noted nothing of an unusual nature that would cause NSAI to take exception with the estimates, in the aggregate, prepared by us. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for auditing the estimates meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

The technical person primarily responsible for overseeing preparation of the reserves estimates and the third party reserves audit is our Director of Reserves and Production Services. The Director’s qualifications include 33 years of reserves evaluation experience, a B.S. in geology from the University of Texas at Austin, an M.S. in Physical Sciences from the University of Houston and membership in the American Association of Petroleum Geologists and The Society of Petroleum Engineers.

Proved undeveloped reserves

The majority of our reserves is concentrated in unconventional tight-sands and shale oil and gas reservoirs. We use available geoscience and engineering data to establish drainage areas and reservoir continuity beyond one direct offset from a producing well, which may provide for additional proved undeveloped reserves. Inherent in the methodology is a requirement for significant well density of economically producing wells to establish reasonable certainty. In fields where producing wells are less concentrated, generally only direct offsets from proved producing wells were assigned the proved undeveloped reserves classification. No new technologies were used to assign proved undeveloped reserves.

At December 31, 2015, after taking into account the proved undeveloped reserves attributable to our acquisition of RKI, our proved undeveloped reserves were 181 MMboe, a decrease of 93 MMboe from our December 31, 2014 proved undeveloped reserves estimate of 274 MMboe. The 181 MMboe represents 31 percent of our total proved reserves at December 31, 2015 as compared with 274 MMboe which was 38 percent of our total proved reserves as of December 31, 2014. Included in the 181 MMboe is 76 MMboe related to the Piceance Basin for which an agreement was signed in February 2016 for the sale of our interests in the basin. Below is a reconciliation of our proved undeveloped reserves for 2015:

	MMboe	% of December 31, 2014	% of December 31, 2015
Proved Undeveloped Reserves at December 31, 2014	274		
Converted to Proved Developed Reserves	(26)	(9)%	(14)%
Extensions and Discoveries	21	8%	12%
Revisions	(108)	(39)%	(60)%
Acquisitions	42	15%	23%
Divestitures	(22)	(8)%	(12)%
Proved Undeveloped Reserves at December 31, 2015	181		

During 2015, 26 MMboe of our December 31, 2014 proved undeveloped reserves were converted to proved developed reserves at a cost of $251 million. This represents a proved undeveloped conversion rate of 9 percent. Of the converted reserves, 39 percent were in the San Juan Basin primarily in the Gallup formation, 32 percent were in the Piceance Basin primarily in the Williams Fork formation and 29 percent were in the Bakken and Three Forks formations in the Williston Basin.

The 21 MMboe of extensions and discoveries were primarily in our oil areas of San Juan Gallup and Williston. In 2015, net negative revisions for our proved undeveloped reserves were 108 MMboe and reflected downward revisions of 139 MMboe reduction of reserves based on the 12 month trailing prices including 109 MMboe associated with uneconomic locations based on the 12 month trailing prices, partially offset by 31 MMboe of net upward revisions primarily due to technical items including improved well economics. Of the 139 MMboe downward revisions, 57 percent relates to the Piceance Basin, 27 percent related to the Williston Basin assets and 8 percent relates to our San Juan Basin legacy assets.

The 42 MMboe of acquisitions relates to the Permian Basin. The 22 MMboe of divestitures relate to the Appalachia properties sold in January 2015 and the Powder River Basin properties sold in September 2015.

All proved undeveloped locations are scheduled to be drilled within the next five years. Development drilling schedules are subject to revision and reprioritization throughout the year resulting from unknown factors such as the relative success of individual developmental drilling prospects, rig availability, title issues or delays and the effect that acquisitions or dispositions may have on prioritizing developmental drilling plans for maximizing returns of capital spent. As previously noted, 76 MMboe of our proved undeveloped reserves at December 31, 2015 are related to the Piceance Basin and subject to a divestiture agreement signed in February 2016.

Oil and Gas Production, Production Prices and Production Costs

Production Sales Data

The following table summarizes our net production sales volumes for the years indicated.

	Year Ended December 31,		
	2015	2014	2013
Oil (Mbbls)			
Permian Basin(a)	1,261	—	—
Williston Basin	7,958	7,123	4,828
San Juan Basin	3,252	1,426	295
Piceance Basin	530	676	690
Other	9	19	106
Total	13,010	9,244	5,919
Natural Gas (MMcf)			
Permian Basin(a)	4,217	—	—
Williston Basin	4,284	3,056	1,610
San Juan Basin	47,093	40,133	42,551
Piceance Basin	181,201	205,853	219,317
Other	10,594	31,344	32,456
Total	247,389	280,386	295,934
NGLs (Mbbls)			
Permian Basin(a)	409	—	—
Williston Basin	720	538	292
San Juan Basin	1,247	327	92
Piceance Basin	4,877	5,352	6,963
Other	36	33	68
Total	7,289	6,250	7,415
Combined Equivalent Volumes (Mboe)	61,530	62,225	62,657
Combined Equivalent Volumes (MMcfe)	369,181	373,352	375,940
Average Daily Combined Equivalent Volumes (Mboe/d)			
Permian Basin(b)	6.5	—	—
Williston Basin	25.7	22.4	14.7
San Juan Basin	33.8	23.1	20.5
Piceance Basin	97.6	110.5	121.1
Other	5.0	14.5	15.4
Total	168.6	170.5	171.7

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(a) Reflects production subsequent to the Acquisition date of August 17, 2015.

(b) The 6.5 Mboe/d for the Permian Basin assumes 365 days. Since the time of acquisition, August 17, 2015, the per day volume is 17.4 Mboe.

Realized average price per unit

The following table summarizes our sales prices for the years indicated.

	Year Ended December 31, 2015	2014	2013
Oil(a):			
Oil excluding all derivative settlements (per barrel)	$39.55	$78.32	$90.21
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)	29.94	2.01	1.52
Oil net price including all derivative settlements (per barrel)	$69.49	$80.33	$91.73
Natural gas(a):			
Natural gas excluding all derivative settlements not designated as hedges (per Mcf)	$2.27	$3.57	$3.03
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per Mcf)	1.05	(0.10)	(0.07)
Natural gas net price including all derivative settlements (per Mcf)	$3.32	$3.47	$2.96
NGL(a):			
NGL excluding all derivative settlements (per barrel)	$13.23	$32.79	$30.72
Impact of net cash received (paid) related to settlement of derivatives not designated as hedges (per barrel)	—	1.12	0.08
NGL net price including all derivative settlements (per barrel)	$13.23	$33.91	$30.80
Combined commodity price per Mboe, including all derivative settlements	$29.62	$31.02	$26.46

(a) Realized average prices reflect market prices, net of fuel, shrink, transportation and fractionation, and processing.

Expenses per Mboe

The following table summarizes our costs for the years indicated.

	Year Ended December 31, 2015	2014	2013
Production costs:			
Lifting costs and workovers (a)	$2.99	$3.25	$2.87
Facilities operating expense	0.34	0.34	0.39
Other operating and maintenance	0.25	0.33	0.37
Total LOE (a)	$3.58	$3.92	$3.63
Gathering, processing and transportation charges	4.59	5.28	5.60
Taxes other than income	1.23	2.02	1.63
Total production cost	$9.40	$11.22	$10.86
General and administrative	$4.05	$4.35	$4.28
Depreciation, depletion and amortization	$15.27	$13.02	$13.69

(a) Excluding Piceance Basin, the lifting costs and workovers are $5.02, $5.96 and $5.46 for 2015, 2014 and 2013, respectively. Total LOE excluding Piceance Basin is $5.59, $6.51 and $5.94 for 2015, 2014 and 2013, respectively.

Productive Oil and Gas Wells

The table below summarizes 2015 productive gross and net wells by area. We use the term “gross” to refer to all wells or acreage in which we have at least a partial working interest and “net” to refer to our ownership represented by that working interest.

	Oil Wells (Gross)	Oil Wells (Net)	Gas Wells (Gross)	Gas Wells (Net)
Permian Basin	1,562	673	99	52
Williston Basin	276	163	—	—
San Juan Basin	149	133	3,164	873
Piceance Basin	—	—	5,060	3,608
Other(a)	—	—	1,150	49
Total	1,987	969	9,473	4,582

(a) Includes Appalachia Basin, Green River Basin and other miscellaneous properties.

At December 31, 2015, there were 307 gross and 158 net producing wells with multiple completions.

Developed and Undeveloped Acreage

The following table summarizes our leased acreage as of December 31, 2015.

	Developed		Undeveloped		Total	
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Permian Basin	127,490	69,202	38,442	25,139	165,932	94,341
Williston Basin	65,366	57,376	66,731	27,359	132,097	84,735
San Juan Basin	256,461	138,157	108,443	87,988	364,904	226,145
Piceance Basin	150,184	122,721	97,779	71,013	247,963	193,734
Other(a)	44,458	12,550	228,862	174,827	273,320	187,377
Total	643,959	400,006	540,257	386,326	1,184,216	786,332

(a) Includes exploratory acreage in Montana, Wyoming, Kansas and other miscellaneous smaller properties.

Drilling and Exploratory Activities

We focus on lower-risk development drilling. Our development drilling success rate was 99 percent in 2015 and 100 percent in 2014 and 2013. Our combined development and exploration success rate was 99 percent in 2015 and 2014, and 100 percent in 2013.

The following table summarizes the number of wells drilled for the periods indicated.

	2015		2014		2013	
	Gross Wells	Net Wells	Gross Wells	Net Wells	Gross Wells	Net Wells
Development wells:						
Permian Basin(a)	19	16	—	—	—	—
Williston Basin	21	13	55	45	51	36
San Juan Basin	53	46	47	44	9	9
Piceance Basin	62	60	267	250	249	236
Other(b)	34	—	42	7	61	24
Development well total	189	135	411	346	370	305
Productive	188	134	411	346	370	305
Nonproductive	1	1	—	—	—	—
Exploration wells:						
Productive	—	—	2	2	9	9
Nonproductive(c)	1	1	5	5	—	—
Exploration well total	1	1	7	7	9	9
Total Drilled	190	136	418	353	379	314

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(a) Reflects wells drilled since the Acquisition date of August 17, 2015.
(b) Includes Appalachia Basin, Green River Basin and other miscellaneous properties.
(c) Reflects exploration wells which were drilled and not completed.

Total gross operated wells drilled were 147, 369 and 361 in 2015, 2014 and 2013, respectively.

Present Activities

At December 31, 2015, we had 7 gross (7 net) wells in the process of being drilled. As previously noted in Significant Properties, we also have a large number of wells that are awaiting completion.

Scheduled Lease Expirations

The table below sets forth, as of December 31, 2015, the gross and net acres scheduled to expire over the next several years. The acreage will not expire if we are able to establish production by drilling wells on the lease prior to the expiration date.

	2016	2017	2018	2019+	Total
Permian Basin	5,062	3,567	1,680	1,378	11,687
Williston Basin	226	426	586	161	1,399
San Juan Basin	1,243	4,961	16,005	26,282	48,491
Piceance Basin	5,634	13	360	11,460	17,467
Other(a)	53,811	58,897	31,272	48,915	192,895
Total (Gross Acres)	65,976	67,864	49,903	88,196	271,939

	2016	2017	2018	2019+	Total
Permian Basin	2,215	2,849	871	1,169	7,104
Williston Basin	226	288	584	156	1,254
San Juan Basin	1,147	4,961	15,913	25,096	47,117
Piceance Basin	4,412	13	367	10,498	15,290
Other(a)	40,981	44,186	28,035	45,719	158,921
Total (Net Acres)	48,981	52,297	45,770	82,638	229,686

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(a) Includes Appalachia Basin, Green River Basin and other miscellaneous properties.

Gas Management

Our sales and marketing activities include the sale of our natural gas, oil and NGL production along with third-party purchases and sales of natural gas, which includes 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 activity. We primarily engage in these activities to enhance the value received from the sale of our natural gas and oil production. 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. Transportation capacity demand payments associated with contracts that are currently not utilized to support our development activities are captured as an expense item in gas management or in discontinued operations.

Seasonality

Generally, the demand for natural gas decreases during the spring and fall months and increases during the winter months and in some areas during the summer months. Seasonal anomalies such as mild winters or hot summers can lessen or intensify this fluctuation. Conversely, during extreme weather events such as blizzards, hurricanes, or heat waves, pipeline systems can become temporarily constrained thus amplifying localized price volatility. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer months. This can lessen seasonal demand fluctuations. World weather and resultant prices for liquefied natural gas can also affect deliveries of competing liquefied natural gas into this country from abroad, affecting the price of domestically produced natural gas. In addition, adverse weather conditions can also affect our production rates or otherwise disrupt our operations.

Hedging Activity

To manage the commodity price risk and volatility associated with owning producing natural gas, crude oil and NGL properties, we enter into derivative contracts for a portion of our expected future production. See further discussion in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Customers

Oil, natural gas and NGL production is sold through our sales and marketing activities to a variety of purchasers under various length contracts ranging from one day to multi-year under various pricing structures. Our third-party customers include other producers, utility companies, power generators, banks, marketing and trading companies and midstream service providers. In 2015, we did not have any customers that accounted for 10 percent or more of our consolidated revenues. We believe that the loss of one or more of our current natural gas, oil or NGLs purchasers would not have a material adverse effect on our ability to sell our production, because any individual purchaser could be readily replaced by other purchasers, absent a broad market disruption.

REGULATORY MATTERS

The oil and natural gas industry is extensively regulated by numerous federal, state, local and foreign authorities, including Native American tribes in the United States. Legislation affecting the oil and natural gas industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Also, numerous departments and agencies, both federal and state, and Native American tribes are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for noncompliance. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, these burdens generally do not affect us any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

The availability, terms and cost of transportation significantly affect sales of oil and natural gas. The interstate transportation and sale for resale of oil and natural gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the FERC. Federal and state regulations govern the price and terms for access to oil and natural gas pipeline transportation. The FERC’s regulations for interstate oil and natural gas transmission in some circumstances may also affect the intrastate transportation of oil and natural gas.

Although oil and natural gas prices are currently unregulated, Congress historically has been active in the area of oil and natural gas regulation. We cannot predict whether new legislation to regulate oil and natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on our operations. Sales of natural gas, oil, condensate and NGLs are not currently regulated and are made at market prices.

Drilling and Production

Our operations are subject to various types of regulation at federal, state, local and Native American tribal levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states, and some counties, municipalities and Native American tribal areas where we operate also regulate one or more of the following activities:

- the location of wells;
- the method of drilling and casing wells;
- the timing of construction or drilling activities including seasonal wildlife closures;
- the employment of tribal members or use of tribal owned service businesses;
- the rates of production or “allowables”;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the notice to surface owners and other third parties; and
- the use, maintenance and restoration of roads and bridges used during all phases of drilling and production.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose requirements regarding the ratability of production. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells, or to limit the number of locations we can drill.

Federal, state and local regulations provide detailed requirements in areas where we operate for the abandonment of wells, closure or decommissioning of production facilities and pipelines, and site restoration. Most states have an administrative agency that requires the posting of performance bonds to fulfill financial requirements for owners and operators on state land. The Army Corps of Engineers and many other state and local authorities also have regulations for plugging and abandonment, decommissioning and site restoration. Although the Army Corps of Engineers does not require bonds or other financial assurances, some state agencies and municipalities do have such requirements.

Natural Gas Sales and Transportation

Historically, federal legislation and regulatory controls have affected the price of the natural gas we produce and the manner in which we market our production. The FERC has jurisdiction over the transportation and sale for resale of natural gas in interstate commerce by natural gas companies under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Various federal laws enacted since 1978 have resulted in the complete removal of all price and non-price controls for sales of domestic natural gas sold in first sales, which include all of our own production. Under the Energy Policy Act of 2005, the FERC has substantial enforcement authority to prohibit the manipulation of natural gas markets and enforce its rules and orders, including the ability to assess substantial civil penalties.

The FERC also regulates interstate natural gas transportation rates and service conditions and establishes the terms under which we may use interstate natural gas pipeline capacity, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas and release of our natural gas pipeline capacity. Commencing in 1985, the FERC promulgated a series of orders, regulations and rule makings that significantly fostered competition in the business of transporting and marketing natural gas. Today, interstate pipeline companies are required to provide nondiscriminatory transportation services to producers, marketers and other shippers, regardless of whether such shippers are affiliated with them. The FERC’s initiatives have led to the development of a competitive, open access market for natural gas purchases and sales that permits all purchasers of natural gas to buy directly from third-party sellers other than pipelines. However, the natural gas industry historically has been very heavily regulated; therefore, we cannot guarantee that the less stringent regulatory approach currently pursued by the FERC and Congress will continue indefinitely into the future nor can we determine what effect, if any, future regulatory changes might have on our natural gas related activities.

Under the FERC's current regulatory regime, transmission services must be provided on an open-access, nondiscriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has in the past reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of transporting natural gas to point-of-sale locations.

Oil Sales and Transportation

Sales of crude oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our crude oil sales are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act and intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorating provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Operation on Native American Reservations

A portion of our leases are, and some of our future leases may be, regulated by Native American tribes. In addition to regulation by various federal, state, and local agencies and authorities, an entirely separate and distinct set of laws and regulations applies to lessees, operators and other parties within the boundaries of Native American reservations in the United States. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the Office of Natural Resources Revenue and BLM, and the Environmental Protection Agency ("EPA"), together with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American reservations. These regulations include lease provisions, royalty matters, drilling and production requirements, environmental standards, tribal employment contractor preferences and numerous other matters.

Native American tribes are subject to various federal statutes and oversight by the Bureau of Indian Affairs and BLM. However, each Native American tribe is a sovereign nation and has the right to enact and enforce certain other laws and regulations entirely independent from federal, state and local statutes and regulations, as long as they do not supersede or conflict with such federal statutes. These tribal laws and regulations include various fees, taxes, requirements to employ Native American tribal members or use tribal owned service businesses and numerous other conditions that apply to lessees, operators and contractors conducting operations within the boundaries of a Native American reservation. Further, lessees and operators within a Native American reservation are often subject to the Native American tribal court system, unless there is a specific waiver of sovereign immunity by the Native American tribe allowing resolution of disputes between the Native American tribe and those lessees or operators to occur in federal or state court.

Therefore, we are subject to various laws and regulations pertaining to Native American tribal surface ownership, Native American oil and gas leases, fees, taxes and other burdens, obligations and issues unique to oil and gas ownership and operations within Native American reservations. One or more of these requirements, or delays in obtaining necessary approvals or permits pursuant to these regulations, may increase our costs of doing business on Native American tribal lands and have an impact on the economic viability of any well or project on those lands.

ENVIRONMENTAL MATTERS

Our operations are subject to numerous federal, state, local, Native American tribal and foreign laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Applicable

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U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), the Clean Water Act ("CWA") and the Clean Air Act ("CAA"). These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress and federal and state agencies frequently revise the environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, EPA's 2011 – 2013 and 2014 – 2016 National Enforcement Initiatives include Energy Extraction and "Assuring Energy Extraction Activities Comply with Environmental Laws." According to the EPA's website, "some techniques for natural gas extraction pose a significant risk to public health and the environment." To address these concerns, the EPA's goal is to "address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment." The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The environmental laws and regulations that could have a material impact on the oil and natural gas exploration and production industry and our business are as follows:

Hazardous Substances and Wastes. CERCLA, also known as the "Superfund law," imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed of or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act ("RCRA") generally does not regulate wastes generated by the exploration and production of natural gas and oil. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the CWA, RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

Waste Discharges. The CWA and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. On February 16, 2012, the EPA issued the final 2012 construction general permit ("CGP") for stormwater discharges from construction activities involving more than one acre, which will provide coverage for a five-year period. The 2012 CGP modifies the prior CGP to implement the new Effluent Limitations Guidelines and New Source Performance Standards for the Construction and Development Industry. The new rule includes new and more stringent restrictions on erosion and sediment control, pollution prevention and stabilization, although a numeric turbidity limit for certain larger construction sites has been stayed as of January 4, 2011.

Air Emissions. The CAA and associated state laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants and greenhouse gases ("GHGs") have been developed by the EPA and may increase the costs of compliance for some facilities. In 2012, the EPA issued federal regulations affecting our operations under the New Source Performance Standards provisions (new Subpart OOOO) and expanded regulations under national emission standards for hazardous air pollutants, although implementation of some of the more rigorous requirements was not required until 2015.

Oil Pollution Act. The Oil Pollution Act of 1990, as amended ("OPA"), and regulations thereunder impose a variety of requirements on "responsible parties" related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A "responsible party" includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species Act. The Endangered Species Act (“ESA”) restricts activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Worker Safety. The Occupational Safety and Health Act (“OSHA”) and comparable state statutes regulate the protection of the health and safety of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Safe Drinking Water Act. The Safe Drinking Water Act (“SDWA”) and comparable state statutes restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, includes the state oil and gas regulatory authority or the state’s environmental authority. These regulations may increase the costs of compliance for some facilities.

Hydraulic Fracturing. We ordinarily use hydraulic fracturing as a means to maximize the productivity of our oil and gas wells in all of the basins in which we operate. In particular, all of our wells that we drill and complete in our core assets such as Permian, Williston and San Juan require hydraulic fracturing for production. Although average drilling and completion costs for each basin will vary, as will the cost of each well within a given basin, on average approximately one-third of the drilling and completion costs for each of our wells for which we use hydraulic fracturing is associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditure budget.

The protection of groundwater quality is extremely important to us. We follow applicable standard industry practices and legal requirements for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the BLM with respect to federal acreage), which conduct many inspections during operations that include hydraulic fracturing. Industry standards and legal requirements for groundwater protection focus on six principal areas: (i) pressure testing of well construction and integrity, (ii) lining of pits used to hold water and other fluids used in the drilling process isolated from surface water and groundwater, (iii) casing and cementing practices for wells to ensure separation of the production zone from groundwater, (iv) disclosure of the chemical content of fracturing liquids, (v) setback requirements as to the location of waste disposal areas, and (vi) pre- and post-drilling groundwater sampling. The legal requirements relating to the protection of surface water and groundwater vary from state to state and there are also federal regulations and guidance that apply to all domestic drilling. In addition, the American Petroleum Institute publishes industry standards and guidance for hydraulic fracturing and the protection of surface water and groundwater. Our policy and practice is to follow all applicable guidelines and regulations in the areas where we conduct hydraulic fracturing.

In addition to the required use of and specifications for casing and cement in well construction, we observe regulatory requirements and what we consider best practices to ensure wellbore integrity and full isolation of any underground aquifers and protection of surface waters. These include the following:

- Prior to perforating the production casing and hydraulic fracturing operations, the casing is pressure tested.
- Before the fracturing operation commences, all surface equipment is pressure tested, which includes the wellhead and all pressurized lines and connections leading from the pumping equipment to the wellhead. During the pumping phases of the hydraulic fracturing treatment, specialized equipment is utilized to monitor and record surface pressures, pumping rates, volumes and chemical concentrations to ensure the treatment is proceeding as designed and the wellbore integrity is sound. Should any problem be detected during the hydraulic fracturing treatment, the operation is shut down until the problem is evaluated, reported and remediated.
- As a means to protect against the negative impacts of any potential surface release of fluids associated with the hydraulic fracturing operation, special precautions are taken to ensure proper containment and storage of fluids. For example, any earthen pits containing non-fresh water must be lined with a synthetic impervious liner. These pits are tested regularly, and in certain sensitive areas have additional leak detection systems in place. At least two feet of freeboard, or available capacity, must be present in the pit at all times. In addition, earthen berms are constructed around any storage tanks, any fluid handling equipment, and in some cases around the perimeter of the location to contain any fluid releases. These berms are considered to be a “secondary” form of containment and serve as an added measure for the protection of groundwater.
- We conduct baseline water monitoring in many of the basins in which we use hydraulic fracturing.
- In Colorado we perform baseline water monitoring required by the Colorado Oil and Gas Conservation Commission.
- The BLM may require baseline water monitoring as a condition of approval for drilling permits.
-

In Pennsylvania, we perform baseline water monitoring pursuant to Pennsylvania Department of Environmental Protection requirements.

- There are currently no regulatory requirements to conduct baseline water monitoring in the Williston Basin, the Permian Basin or the New Mexico portion of our San Juan Basin assets. The majority of our assets in the San Juan Basin are on federal lands, and there are few cases where water wells are within one to two miles of our wells, which is outside the range that we would typically sample.

Once a pipe is set in place, cement is pumped into the well where it hardens and creates a permanent, isolating barrier between the steel casing pipe and surrounding geological formations. This aspect of the well design essentially eliminates a “pathway” for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. Furthermore, in the basins in which we conduct hydraulic fracturing, the hydrocarbon bearing formations are separated from any usable underground aquifers by thousands of feet of impermeable rock layers. This wide separation serves as a protective barrier, preventing any migration of fracturing fluids or hydrocarbons upwards into any groundwater zones.

In addition, the vendors we employ to conduct hydraulic fracturing are required to monitor all pump rates and pressures during the fracturing treatments. This monitoring occurs on a real-time basis and data is recorded to ensure protection of groundwater.

The cement and steel casing used in well construction can have rare failures. Any failure in isolation is reported to the applicable oil and gas regulatory body. A remediation procedure is written and approved and then completed on the well before any further operations or production is commenced. Possible isolation failures may result from:

- Improper cementing work. This can create conditions in which hydraulic fracturing fluids and other natural occurring substances can migrate into the surrounding geological formation. Production casing cementing tops and cement bond effectiveness are evaluated using either a temperature log or an acoustical cement bond log prior to any completion operations. If the cement bond or cement top is determined to be inadequate for zone isolation, remedial cementing operations are performed to fill any voids and re-establish integrity. As part of this remedial operation, the casing is again pressure tested before fracturing operations are initiated.
- Initial casing integrity failure. The casing is pressure tested prior to commencing completion operations. If the test fails due to a compromise in the casing, the applicable oil and gas regulatory body will be notified and a remediation procedure will be written, approved and completed before any further operations are conducted. In addition, casing pressures are monitored throughout the fracturing treatment and any indication of failure will result in an immediate shutdown of the operation.
- Well failure or casing integrity failure during production. Loss of wellbore integrity can occur over time even if the well was correctly constructed due to downhole operating environments causing corrosion and stress. During production, the bradenhead, casing and tubing pressures are monitored and a casing failure can be identified and evaluated. Remediation could include placing additional cement behind casing, installing a casing patch, or plugging and abandoning the well, if necessary.
- “Fluid leakoff” during the fracturing process. Fluid leakoff can occur during hydraulic fracturing operations whereby some of the hydraulic fracturing fluid flows through the artificially created fractures into the micropore or pore spaces within the formation, existing natural fractures in the formation, or small fractures opened into the formation by the pressure in the induced fracture. Fluid leakoff is accounted for in the volume design of nearly every fracturing job and “pump-in” tests are often conducted prior to fracturing jobs to estimate the extent of fluid leakoff. In certain situations, very fine grain sand is added in the initial part of the treatment to seal-off any small fractures of micropore spaces and mitigate fluid leak-off.

Approximately 99 percent of hydraulic fracturing fluids are made up of water and sand. We utilize major hydraulic fracturing service companies whose research departments conduct ongoing development of “greener” chemicals that are used in fracturing. We evaluate, test, and where appropriate adopt those products that are more environmentally friendly. We have also chosen to participate in a voluntary fracturing chemical registry that is a public website: www.fracfocus.org at which interested persons can find out information about fracturing fluids. This registry is a joint project of the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission and provides our industry with an avenue to voluntarily disclose chemicals used in the hydraulic fracturing process. The Company registered with the FracFocus Chemical Disclosure Registry in April 2011 and began uploading data when the registry went live on April 11, 2011. Through December 31, 2015, we have loaded data on more than 1,601 wells, including data relating to wells fractured since January 1, 2011, to the site. Consistent with other industry participants, we are not planning to add data on wells drilled prior to 2011. The information included on this website is not incorporated by reference in this Annual Report on Form 10-K.

In 2015, we used recycled water in two of our four basins, and continue to evaluate expanding the use of recycled water for our hydraulic fracturing operations where technically and economically feasible. This recycling process lessens the demand on local natural water resources. Any water that is recovered in our operations that is not used for our hydraulic fracturing operations is safely disposed in accordance with the state and federal rules and regulations in a manner that does not impact underground aquifers and surface waters.

Despite our efforts to minimize impacts on the environment from hydraulic fracturing activities, in light of the volume of our hydraulic fracturing activities, we have occasionally been engaged in litigation and received requests for information, notices of alleged violation, and citations related to the activities of our hydraulic fracturing vendors, none of which has resulted in any material costs or penalties.

Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. Both the United States House of Representatives and Senate have considered Fracturing Responsibility and Awareness of Chemicals Act ("FRAC Act") and a number of states, including states in which we have operations, are looking to more closely regulate hydraulic fracturing due to concerns about water supply. The recent congressional legislative efforts seek to regulate hydraulic fracturing to Underground Injection Control program requirements, which would significantly increase well capital costs. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program, and on May 10, 2012, the EPA published its proposed guidance on the issue. The public comment period for the proposed permitting guidance closed in 2012, and the EPA issued its final guidance in February 2014. In August 2015, the EPA published its Final 2014 Effluent Guidelines Program Plans under the CWA confirming its intention to regulate wastewater discharges from on-shore Unconventional Oil and Gas Extraction and to specifically investigate centralized water treatment facilities that accept oil and gas extraction wastewaters. The EPA is also collecting information as part of a study into the effects of hydraulic fracturing on drinking water. The EPA published its Draft "Assessment of Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources" in June 2015, which was released for public comment that closed at the end of 2015. Although the Draft Assessment concluded that "[w]e did not find evidence that these mechanisms have led to widespread, systemic impacts on drinking water resources in the United States," the final report could result in additional regulations, which could lead to operational burdens similar to those described above. In connection with the EPA study, we have received and responded to a request for information from the EPA for 52 of our wells located in various basins that have been hydraulically fractured. The requested information covers well design, construction and completion practices, among other things. We understand that similar requests were sent to eight other companies that own or operate wells that utilized hydraulic fracturing.

In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a final report on hydraulic fracturing in November 2011. The report concludes that the risk of fracturing fluids contaminating drinking water sources through fractures in the shale formations "is remote." It also states that development of the nation's shale resources has produced major economic benefits. The report includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters. The Government Accountability Office is also examining the environmental impacts of produced water and the Counsel for Environmental Quality has been petitioned by environmental groups to develop a programmatic environmental impact statement under NEPA for hydraulic fracturing. The United States Department of the Interior is also considering whether to impose disclosure requirements or other mandates for hydraulic fracturing on federal land.

Several states, including Pennsylvania, Colorado, North Dakota, New Mexico and Wyoming, have adopted or are considering adopting, regulations that could restrict or impose additional requirements related to hydraulic fracturing. For example, Pennsylvania requires that detailed information be disclosed regarding the hydraulic fracturing fluids, including but not limited to, a list of chemical additives, volume of each chemical added, and list of chemicals in the material safety data sheets. Since June 2009, Colorado has required all operators to maintain a chemical inventory by well site for each chemical product used downhole or stored for use downhole during drilling, completion and workover operations, including fracture stimulation in an amount exceeding 500 pounds during any quarterly reporting period. Colorado adopted its final hydraulic fracturing chemical disclosure rules on December 13, 2011. Wyoming, New Mexico and Texas require public disclosure of chemicals used in hydraulic fracturing. Disclosure of chemicals used in the hydraulic fracturing process could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. A number of states have also adopted regulations increasing the setback requirements, or are in the process of rulemaking to address the issue, including Colorado, New Mexico, Wyoming, Texas and Pennsylvania.

In addition, a number of local governments in Colorado have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities, while some state and local governments in the Appalachian Basin and San Juan Basin in New Mexico have considered or imposed temporary moratoria on drilling operations using hydraulic fracturing until further study of the potential environmental and human health impacts by the EPA or the relative state agencies are completed. Additionally, publicly operated treatment works facilities in

Pennsylvania have ceased taking wastewater from hydraulic fracturing operations, and we are now recycling this wastewater and utilizing it in subsequent hydraulic fracturing operations. Certain organizations have promoted ballot initiatives at the local level that are aimed at imposing restrictions on hydraulic fracturing, and may attempt to do the same on a wider basis in one or more states where we operate. At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

Global Warming and Climate Change. Recent scientific studies have suggested that emissions of GHGs, including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere. Both houses of Congress have previously considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The EPA has begun to regulate GHG emissions. On December 7, 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the CAA. The EPA issued a final rule that went into effect in 2011 that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions. On November 30, 2010, the EPA published its final rule expanding the existing GHG monitoring and reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage, and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis, and our reporting began in 2012 for emissions occurring in 2011. We are required to report our GHG emissions under this rule but are not subject to GHG permitting requirements. Several of the EPA's GHG rules are being challenged in court proceedings and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules.

Because regulation of GHG emissions is relatively new, further regulatory, legislative and judicial developments are likely to occur. In March 2014, the White House published the President's Climate Action Plan Strategy to Reduce Methane Emissions. In August 2015, EPA proposed its new NSPS OOOOa requirements, which add additional methane reduction requirements applicable to the oil and gas sector for both new and modified sources. Such developments may affect how these GHG initiatives will impact our operations. In addition to these regulatory developments, recent judicial decisions have allowed certain tort claims alleging property damage to proceed against GHG emissions sources and may increase our litigation risk for such claims. New legislation or regulatory programs that restrict emissions of or require inventory of GHGs in areas where we operate have adversely affected or will adversely affect our operations by increasing costs. The cost increases so far have resulted from costs associated with inventorying our GHG emissions, and further costs may result from the potential new requirements to obtain GHG emissions permits, install additional emission control equipment and an increased monitoring and record-keeping burden.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas or otherwise cause us to incur significant costs in preparing for or responding to those effects.

COMPETITION

We compete with other oil and gas concerns, including major and independent oil and gas companies in the development, production and marketing of oil and natural gas. We compete in areas such as acquisition of oil and gas properties and obtaining necessary equipment, supplies and services. We also compete in recruiting and retaining skilled employees.

EMPLOYEES

At December 31, 2015, we had approximately 1,040 full-time employees.

FINANCIAL INFORMATION ABOUT SEGMENTS

We operate in the exploration and production segment of the oil and gas industry and our operations are conducted in the United States. We report our financial results as a single industry segment.

WEBSITE ACCESS TO REPORTS AND OTHER INFORMATION

We make available free of charge through our website, www.wpxenergy.com/investors, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements, other reports filed under the Securities Exchange Act of 1934 (“Exchange Act”) and all amendments to those reports simultaneously or as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC. Our reports are also available free of charge on the SEC’s website, www.sec.gov. You may inspect and copy our reports at the SEC’s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the Public Reference Room. Also available free of charge on our website are the following corporate governance documents:

- Amended and Restated Certificate of Incorporation
- Restated Bylaws
- Corporate Governance Guidelines
- Code of Business Conduct, which is applicable to all WPX Energy directors and employees, including the principal executive officer, the principal financial officer and the principal accounting officer
- Audit Committee Charter
- Compensation Committee Charter
- Nominating and Governance Committee Charter

All of our reports and corporate governance documents may also be obtained without charge by contacting Investor Relations, WPX Energy, Inc., 3500 One Williams Center, Tulsa, Oklahoma 74172.

We maintain an Internet site at www.wpxenergy.com. We do not incorporate our Internet site, or the information contained on that site or connected to that site, into this Annual Report on Form 10-K.

Item 1A. Risk Factors

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 Annual Report on Form 10-K include forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters.

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

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

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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. These factors are described in “Risk Factors.”

RISK FACTORS

You should carefully consider each of the following risks, which we believe are the principal risks that we face and of which we are currently aware, and all of the other information in this report. Some of the risks described below relate to our business, while others relate principally to the securities markets and ownership of our common stock. If any of the following risks actually occur, our business, financial condition, cash flows and results of operations could suffer materially and adversely. In that case, the trading price of our common stock could decline, and you might lose all or part of your investment.

Risks Related to Our Business

Our business requires significant capital expenditures and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, development and acquisition activities require substantial capital expenditures. We expect to fund our capital expenditures through a combination of cash flows from operations and, when appropriate, borrowings under our credit facility. Future cash flows are subject to a number of variables, including the level of production from existing wells, prices of oil and natural gas and our success in developing and producing new reserves. If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to sustain our operations at current levels. We may not be able to obtain debt or equity financing on terms favorable to us or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil and natural gas production or reserves, and in some areas a loss of properties.

Failure to replace reserves may negatively affect our business.

The growth of our business depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves generally decline when reserves are produced, unless we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. We may not always be able to find, develop or acquire additional reserves at acceptable costs. If oil and natural gas prices increase, our costs for additional reserves would also increase; conversely if natural gas or oil prices decrease, it could make it more difficult to fund the replacement of our reserves.

Exploration and development drilling may not result in commercially productive reserves.

Our past success rate for drilling projects should not be considered a predictor of future commercial success. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The new wells we drill or participate in may not be commercially productive, and we may not recover all or any portion of our investment in wells we drill or participate in. Our efforts will be unprofitable if we drill dry wells or wells that are productive but do not produce enough reserves to return a profit after drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed, canceled or rendered unprofitable or less profitable than anticipated as a result of a variety of other factors, including:

- increases in the cost of, or shortages or delays in the availability of, drilling rigs and equipment, supplies, skilled labor, capital or transportation;
- equipment failures or accidents;
- adverse weather conditions, such as floods or blizzards;
- title and lease related problems;
- limitations in the market for oil and natural gas;
- unexpected drilling conditions or problems;
- pressure or irregularities in geological formations;
- regulations and regulatory approvals;
- changes or anticipated changes in energy prices; or
- compliance with environmental and other governmental requirements.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas oil properties.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A writedown constitutes a non-cash charge to earnings. For example, due to market conditions including oil and natural gas prices in the fourth quarter of 2015, we performed impairment assessments of our proved and unproved properties. As a result of these assessments which included the possibility of a divestiture, we recorded impairments of capitalized costs of proved producing and unproved properties in the Piceance Basin of approximately $2.3 billion in 2015. In addition to those long-lived assets for which impairment charges were recorded, certain others were reviewed for which no impairment was required. 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 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. We may incur impairment charges for these or other properties in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Estimating reserves and future net revenues involves uncertainties. Decreases in oil and natural gas prices, or negative revisions to reserve estimates or assumptions as to future oil and natural gas prices may lead to decreased earnings, losses or impairment of oil and natural gas assets.

Reserve estimation is a subjective process of evaluating underground accumulations of oil and gas that cannot be measured in an exact manner. Reserves that are “proved reserves” are those estimated quantities of crude oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions and relate to projects for which the extraction of hydrocarbons must have commenced or for which the operator is reasonably certain will commence within a reasonable time.

The process relies on interpretations of available geological, geophysical, engineering and production data. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of developmental expenditures, including many factors beyond the control of the producer. The reserve data included in this report represents estimates. In addition, the estimates of future net revenues from our proved reserves and the present value of such estimates are based upon certain assumptions about future production levels, prices and costs that may not prove to be correct.

Quantities of proved reserves are estimated based on economic conditions in existence during the period of assessment. Changes to oil and gas prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

If negative revisions in the estimated quantities of proved reserves were to occur, it would have the effect of increasing the rates of depreciation, depletion and amortization on the affected properties, which would decrease earnings or result in losses through higher depreciation, depletion and amortization expense. These revisions, as well as revisions in the assumptions of future cash flows of these reserves, may also be sufficient to trigger impairment losses on certain properties which would result in a noncash charge to earnings.

The development of our proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate.

Approximately 31 percent of our total estimated proved reserves at December 31, 2015 were proved undeveloped reserves and may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserves data included in the reserves engineer reports assumes that substantial capital expenditures are required to develop such reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

The present value of future net revenues from our proved reserves will not necessarily be the same as the value we ultimately realize of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we have based the estimated discounted future net revenues from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding 12 months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10 percent discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on units containing the acreage.

A portion of our acreage is not currently held by production. Unless production in paying quantities is established on units containing these leases during their terms, the leases will expire. If we do not extend our leases and our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, oil and natural gas prices, availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory and lease issues.

Prices for oil, natural gas and NGLs are volatile, and this volatility could adversely affect our financial results, cash flows, access to capital and ability to maintain our existing business.

Our revenues, operating results, future rate of growth and the value of our business depend primarily upon the prices of oil, natural gas and NGLs. Price volatility can impact both the amount we receive for our products and the volume of products we sell. Prices affect the amount of cash flow available for capital expenditures and our ability to borrow money under our credit facility or raise additional capital.

The markets for oil, natural gas and NGLs are likely to continue to be volatile. Wide fluctuations in prices might result from relatively minor changes in the supply of and demand for these commodities, market uncertainty and other factors that are beyond our control, including:

- weather conditions;
- the level of consumer demand;
- the overall economic environment;
- worldwide and domestic supplies of and demand for oil, natural gas and NGLs;
- turmoil in the Middle East and other producing regions;

- the activities of the Organization of Petroleum Exporting Countries;
- terrorist attacks on production or transportation assets;
- variations in local market conditions (basis differential);
- the price and availability of other types of fuels;
- the availability of pipeline capacity;
- supply disruptions, including plant outages and transportation disruptions;
- the price and quantity of foreign imports of oil and natural gas;
- domestic and foreign governmental regulations and taxes;
- volatility in the oil and natural gas markets;
- the credit of participants in the markets where products are bought and sold; and
- the adoption of regulations or legislation relating to climate change.

Our business depends on access to oil, natural gas and NGL transportation systems and facilities.

The marketability of our oil, natural gas and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of transportation systems and facilities owned by third parties. For example, we can provide no assurance that sufficient transportation capacity will exist for expected production from the Permian Basin, Williston Basin and San Juan Basin or that we will be able to obtain sufficient transportation capacity on economic terms.

A lack of available capacity on transportation systems and facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these systems and facilities for an extended period of time could negatively affect our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

We may have excess capacity under our firm transportation contracts, or the terms of certain of those contracts may be less favorable than those we could obtain currently.

We have entered into contracts for firm transportation that may exceed our transportation needs. Any excess transportation commitments will result in excess transportation costs that could negatively affect our results of operations. In addition, certain of the contracts we have entered into may be on terms less favorable to us than we could obtain if we were negotiating them at current rates, which also could negatively affect our results of operations.

We have limited control over activities on properties we do not operate, which could reduce our production and revenues.

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations or an operator's breach of the applicable agreements could reduce our production and revenues or increase our costs. As of December 31, 2015 , we were not the operator of approximately 6 percent of our total net production. The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

We might not be able to successfully manage the risks associated with selling and marketing products in the wholesale energy markets.

Our portfolio of derivative and other energy contracts includes wholesale contracts to buy and sell oil, natural gas and NGLs that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate or cannot manage, it could negatively affect our results of operations. In the past, certain marketing and trading companies have experienced severe financial problems due to price volatility in the energy commodity markets. In certain instances this volatility has caused companies to be unable to deliver energy commodities that they had guaranteed under contract. If such a delivery failure were to occur in one of our contracts, we might incur additional losses to the extent of amounts, if any, already paid to, or received from, counterparties. In addition, in our business, we often extend credit to our counterparties. We are exposed to the risk that we might not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral that secures our counterparty's obligation is inadequate, we will suffer a loss. Downturns in the economy or disruptions in the global credit markets could cause more of our counterparties to fail to perform than we expect.

Our commodity price risk management and measurement systems and economic hedging activities might not be effective and could increase the volatility of our results.

The systems we use to quantify commodity price risk associated with our businesses might not always be followed or might not always be effective. Further, such systems do not in themselves manage risk, particularly risks outside of our control, and adverse changes in energy commodity market prices, volatility, adverse correlation of commodity prices, the liquidity of markets, changes in interest rates and other risks discussed in this report might still adversely affect our earnings, cash flows and balance sheet under applicable accounting rules, even if risks have been identified.

Furthermore, no single hedging arrangement can adequately address all commodity price risks present in a given contract. For example, a forward contract that would be effective in hedging commodity price volatility risks would not hedge the contract's counterparty credit or performance risk. Therefore, unhedged risks will always continue to exist.

Our use of derivatives through which we attempt to reduce the economic risk of our participation in commodity markets could result in increased volatility of our reported results. Changes in the fair values (gains and losses) of derivatives that qualify as hedges under GAAP to the extent that such hedges are not fully effective in offsetting changes to the value of the hedged commodity, as well as changes in the fair value of derivatives that do not qualify or have not been designated as hedges under GAAP, must be recorded in our income. This creates the risk of volatility in earnings even if no economic impact to us has occurred during the applicable period.

The impact of changes in market prices for oil, natural gas and NGLs on the average prices paid or received by us may be reduced based on the level of our hedging activities. These hedging arrangements may limit or enhance our margins if the market prices for oil, natural gas or NGLs were to change substantially from the price established by the hedges. In addition, our hedging arrangements expose us to the risk of financial loss if our production volumes are less than expected.

The swaps regulatory provisions of the Dodd-Frank Act and the rules adopted thereunder could adversely affect our ability to hedge risks associated with our business and could increase the working capital required to conduct these activities and reduce our liquidity.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") and rules thereunder adopted and to be adopted by the Commodity Futures Trading Commission (the "CFTC"), the SEC and other regulators establish federal regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Title VII of the Dodd-Frank Act ("Title VII") and the rules adopted thereunder impose new statutory and regulatory requirements for derivative transactions in the major energy markets, including swaps, hedging and other transactions.

Title VII requires that certain classes of swaps be cleared on a derivatives clearing organization and that swaps subject to such clearing requirement be executed on a board of trade or swap execution facility unless, in each case, an exemption from the clearing requirement is available to a party to the swap. The CFTC has designated only certain classes of interest rate swaps and index credit default swaps for mandatory clearing. The swaps we currently use are not included in those classes of swaps, and it is unclear when the CFTC will designate those classes of swaps we use, such as physical commodity swaps, for mandatory clearing. Although we believe we will qualify for the end user exception to the mandatory clearing and trade execution requirements for the swaps we enter to hedge our commercial risks, if we do not do so, the clearing of such swaps would require us to post cash or other liquid collateral in connection with those swaps and may cause increased costs to our counterparties that may be reflected in the pricing they make available to us. Moreover, execution of swaps on boards of trade or swap execution facilities may also adversely affect the pricing we are able to obtain for such swaps.

As required by the Dodd-Frank Act, the CFTC and the federal banking regulators have adopted rules requiring certain market participants to collect margin with respect to uncleared swaps from their counterparties that are financial end users and certain registered swap dealers and major swap participants. The requirements of those rules are to be phased commencing on September 1, 2016. Although we believe we will qualify as a non-financial end user for purposes of these rules, were we not to do so and have to post margin as to our uncleared swaps in the future, our cost of entering into and maintaining swaps would be increased. In addition, our counterparties that are subject to the regulations imposing the Basel III capital requirements on them may increase the cost to us of entering into swaps with them or require us to post collateral with them in connection with such swaps to offset their increased capital costs or to reduce their capital costs to maintain those swaps on their balance sheets. Posting of collateral, including under the margin rules, could affect our liquidity, financial flexibility, and available cash.

In accordance with a requirement of Title VII, the CFTC has proposed rules setting limits on the positions market participants may hold in certain core futures and futures equivalent contracts, option contracts or swaps for or linked to certain physical commodities, including Henry Hub natural gas and light sweet crude oil, subject to exceptions for certain bona fide hedging and other types of transactions. The imposition of position limits could compromise our ability to hedge risks associated with our business.

Under the Dodd-Frank Act, certain financial institutions may be required to spin off their activities in structured finance swaps. In the event that any of our historical counterparties spin off some or all of their derivatives activities, the separate entities could be our counterparties in future swaps and may not be as creditworthy as our historical counterparties.

The complete impact of the Dodd-Frank Act on our hedging activities is unknown at this time because the CFTC and the SEC have yet to complete the adoption a number of the rules required to implement the swap provisions of the Dodd-Frank Act and are still in the process of implementing certain of the rules they have adopted. We believe the derivative contracts that we enter into should not be impacted by the position limits for derivatives and that we should generally be eligible to elect the end user exception from the mandatory clearing requirement when it is applicable to our swaps and to qualify as a non-financial end user under the swap margin rules. Nevertheless, there is a risk that the position limits might restrict our ability to enter into swaps in certain instances and that we might not satisfy the conditions to reliance on such end-user exception or qualify as a non-financial end user for purposes of the margin rules. Additionally, the application of the mandatory clearing and trade execution requirements and the margin rules to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. The impact of the swap regulatory regime upon our businesses will depend on, among other factors, the final form of all the rules adopted by the CFTC and other federal regulators and the CFTC's and the other regulators' implementation and enforcement of those rules.

Compliance with the rules adopted and to be adopted by the CFTC and other federal regulatory bodies may significantly increase the cost of entering into and maintaining derivative contracts. The increased costs may include costs associated with swap recordkeeping and reporting requirements as well as any required posting of cash or other liquid collateral for our commodities hedging transactions under circumstances in which we do not currently do so. Posting of additional cash or liquid collateral could also impact our liquidity, reduce cash available for capital expenditures and reduce our ability to execute hedges against commodity price uncertainty to protect cash flows. The Dodd-Frank Act and related swaps rules may lead to material alterations of the terms of derivative contracts we enter, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and the related rules, our results of operations may become more volatile or may otherwise be adversely affected and our cash flows may be less predictable. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act is to lower commodity prices.

Any of the consequences discussed above could have a material adverse effect on our consolidated financial position, results of operations, liquidity and cash flows.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

We face competition in acquiring new properties, marketing oil and natural gas and securing equipment and trained personnel in the oil and natural gas industry.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

Our operations are subject to operational hazards and unforeseen interruptions for which they may not be adequately insured.

There are operational risks associated with drilling for, production, gathering, transporting, storage, processing and treating of oil and natural gas and the fractionation and storage of NGLs, including:

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- hurricanes, tornadoes, floods, extreme weather conditions and other natural disasters;
- aging infrastructure and mechanical problems;
- damages to pipelines, pipeline blockages or other pipeline interruptions;
- uncontrolled releases of oil, natural gas (including sour gas), NGLs, brine or industrial chemicals;
- operator error;
- pollution and environmental risks;
- fires, explosions and blowouts;
- risks related to truck and rail loading and unloading; and
- terrorist attacks or threatened attacks on our facilities or those of other energy companies.

Any of these risks could result in loss of human life, personal injuries, significant damage to property, environmental pollution, impairment of our operations and substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses, and only at levels we believe to be appropriate. The location of certain segments of our facilities in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. In spite of our precautions, an event such as those described above could cause considerable harm to people or property and could have a material adverse effect on our financial condition and results of operations, particularly if the event is not fully covered by insurance. Accidents or other operating risks could further result in loss of service available to our customers.

We do not insure against all potential losses and could be seriously harmed by unexpected liabilities or by the inability of our insurers to satisfy our claims.

We are not fully insured against all risks inherent to our business, including environmental accidents. We do not maintain insurance in the type and amount to cover all possible risks of loss.

We currently maintain excess liability insurance that covers us, our subsidiaries and certain of our affiliates for legal and contractual liabilities arising out of bodily injury or property damage, including resulting loss of use to third parties. This excess liability insurance includes coverage for sudden and accidental pollution liability.

Although we maintain property insurance on certain physical assets that we own, lease or are responsible to insure, the policy may not cover the full replacement cost of all damaged assets. In addition, certain perils may be excluded from coverage or sub-limited. We may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. We may elect to self insure a portion of our risks. All of our insurance is subject to deductibles. If a significant accident or event occurs for which we are not fully insured it could adversely affect our operations and financial condition.

In addition, any insurance company that provides coverage to us may experience negative developments that could impair their ability to pay any of our claims. As a result, we could be exposed to greater losses than anticipated and may have to obtain replacement insurance, if available, at a greater cost.

Potential changes in accounting standards might cause us to revise our financial results and disclosures in the future, which might change the way analysts measure our business or financial performance.

Regulators and legislators continue to take a renewed look at accounting practices, financial and reserves disclosures and companies' relationships with their independent public accounting firms and reserves consultants. It remains unclear what new laws or regulations will be adopted, and we cannot predict the ultimate impact that any such new laws or regulations could have. In addition, the Financial Accounting Standards Board or the SEC could enact new accounting standards that might impact how we are required to record revenues, expenses, assets, liabilities and equity. Any significant change in accounting standards or disclosure requirements could have a material adverse effect on our business, results of operations and financial condition.

Our operating results might fluctuate on a seasonal and quarterly basis.

Our revenues can have seasonal characteristics. In many parts of the country, demand for natural gas and other fuels peaks during the winter. As a result, our overall operating results in the future might fluctuate substantially on a seasonal basis. Demand for natural gas and other fuels could vary significantly from our expectations depending on the nature and location of our facilities and the terms of our natural gas transportation arrangements relative to demand created by unusual weather patterns.

Our significant indebtedness reduces our financial flexibility and could impede our ability to operate.
We have historically operated with, and anticipate continuing to operate with, a significant amount of debt. Our substantial amount of debt, including the debt we incurred in connection with our acquisition of RKI, could have important consequences for investors in our common stock, including the following:

- make it more difficult for us to satisfy our obligations with respect to our revolving credit facility;
- impair our ability to obtain additional financing, if necessary, for working capital, letters of credit or other forms of guarantees, capital expenditures, acquisitions or other purposes or make such financing unavailable on favorable terms;
- require us to dedicate a substantial portion of our cash flow from operations to make payments on our debt, thereby reducing funds available for operations, capital expenditures, future business opportunities and other purposes;
- limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- reduce our ability to make acquisitions or expand our business;
- limit our ability to borrow additional funds;
- limit our ability to sell assets to raise funds if needed for working capital, capital expenditures, acquisitions or other purposes;
- make it difficult for us to pay dividends on shares of our common stock;
- increase our vulnerability to adverse economic and industry conditions, including increases in interest rates; and
- place us at a competitive disadvantage compared to competitors who might have relatively less debt.

Additionally, we may be able to incur substantial additional indebtedness in the future. Although our revolving credit facility contains restrictions on the incurrence of additional indebtedness by our subsidiaries, such restrictions are subject to a number of qualifications and exceptions, and indebtedness incurred in compliance with such restrictions could be substantial. To the extent that new indebtedness is added to our current debt levels.
The market price of our common stock may be volatile or may decline and it may be difficult for you to resell shares of our common stock at prices you find attractive.
The market price of our common stock has historically experienced and may continue to experience volatility. For example, during the twelve months ended December 31, 2015, the high sales price per share of our common stock on the NYSE was $14.65 and the low sales price per share was $5.03. The sales price per share of our common stock has traded as low as $2.53 since December 31, 2015. The market price of our common stock could be subject to wide fluctuations in the future in response to the following events or factors that may vary over time and some of which are beyond our control, including but not limited to:

- changes in oil and natural gas prices, including in different geographic locations;
- demand for oil and natural gas;
- the success of our drilling program;
- changes in our drilling schedule;
- adjustments to our reserve estimates and differences between actual and estimated production, revenue and expenditures;
- competition from other oil and gas companies;
- costs and liabilities relating to governmental laws and regulations and environmental risks;
- general market, political and economic conditions;
- our failure to meet financial analysts' performance or financing expectations;
- changes in recommendations by financial analysts; and
- changes in market valuations of other companies in our industry.

In particular, a significant or extended decline in oil and natural gas prices would have a material adverse effect on our financial position, our results of operations, our access to capital and the quantities of oil and natural gas that we can produce economically.

A failure to close previously announced asset divestitures, a continuation of currently low commodity prices for an extended period of time, and/or an inability to amend our credit facility on acceptable terms, may significantly impact our liquidity.

Liquidity will be of major importance to our industry as companies face lower cash flows from operations and potentially reduced availability of credit under revolving credit agreements as borrowing base re-determinations occur in early 2016. We increased our leverage in 2015 in connection with the Acquisition and then established goals for debt reduction and greater liquidity via asset sales. In total, we targeted $800 million to $1 billion in asset sales. WPX has entered into agreements for the disposition of all of its assets in the Piceance Basin for $910 million and for the sale of gathering assets in the San Juan Basin for $285 million. These divestitures are expected to close in the first or second fiscal quarters of 2016 and will provide proceeds to reduce our debt and/or cash for liquidity. We are currently in discussions with our bank group regarding amendments to our Credit Facility. If the asset divestiture transactions we have entered into were not to close, or if we are unable to amend our Credit Facility on acceptable terms, the resulting adverse impact on our liquidity would be material to our financial condition and results of operations.

Our debt agreements impose restrictions on us that may limit our access to credit and adversely affect our ability to operate our business.

Our credit facility contains various covenants that restrict or limit, among other things, our ability to grant liens, merge or sell substantially all of our assets, make investments, guarantees, loans or advances in non-subsidiaries, enter into certain hedging agreements, incur additional debt and enter into certain affiliate transactions. In addition, our credit facility contains financial covenants, including an additional financial covenant if our credit ratings drop below a specified level, and other limitations with which we will need to comply and which may limit our ability to borrow under the facility. Similarly, the indentures governing our senior notes restrict our ability to grant liens to secure certain types of indebtedness and merge or sell substantially all of our assets. These covenants could adversely affect our ability to finance our future operations or capital needs or engage in, expand or pursue our business activities and prevent us from engaging in certain transactions that might otherwise be considered beneficial to us. Our ability to comply with these covenants may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, our current assumptions about future economic conditions turn out to be incorrect or unexpected events occur, our ability to comply with these covenants may be significantly impaired.

Our failure to comply with the covenants in our debt agreements could result in events of default. Upon the occurrence of such an event of default, the lenders could elect to declare all amounts outstanding under a particular facility to be immediately due and payable and terminate all commitments, if any, to extend further credit. Certain payment defaults or an acceleration under one debt agreement could cause a cross-default or cross-acceleration of another debt agreement. Such a cross-default or cross-acceleration could have a wider impact on our liquidity than might otherwise arise from a default or acceleration of a single debt instrument. If an event of default occurs, or if other debt agreements cross-default, and the lenders under the affected debt agreements accelerate the maturity of any loans or other debt outstanding to us, we may not have sufficient liquidity to repay amounts outstanding under such debt agreements.

Our ability to repay, extend or refinance our debt obligations and to obtain future credit will depend primarily on our operating performance, which will be affected by general economic, financial, competitive, legislative, regulatory, business and other factors, many of which are beyond our control. Our ability to refinance our debt obligations or obtain future credit will also depend upon the current conditions in the credit markets and the availability of credit generally. If we are unable to meet our debt service obligations or obtain future credit on favorable terms, if at all, we could be forced to restructure or refinance our indebtedness, seek additional equity capital or sell assets. We may be unable to obtain financing or sell assets on satisfactory terms, or at all.

Difficult conditions in the global capital markets, the credit markets and the economy in general could negatively affect our business and results of operations.

Our business may be negatively impacted by adverse economic conditions or future disruptions in global financial markets. Included among these potential negative impacts are reduced energy demand and lower commodity prices, increased difficulty in collecting amounts owed to us by our customers and reduced access to credit markets. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing. If financing is not available when needed, or is available only on unfavorable terms, we may be unable to implement our business plans or otherwise take advantage of business opportunities or respond to competitive pressures.

We are subject to risks associated with climate change.

There is a growing belief that emissions of GHGs may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks.

In addition, legislative and regulatory responses related to GHGs and climate change create the potential for financial risk. Numerous states have announced or adopted programs to stabilize and reduce GHGs, as well as their own reporting requirements. On September 22, 2009, the EPA finalized a GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions. On November 8, 2010, the EPA also issued GHG monitoring and reporting regulations specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year-the Greenhouse Gas Reporting Program. The rule requires annual reporting of GHG emissions by regulated facilities to the EPA. We are required to report our GHG emissions to the EPA each year in March under this rule, and the EPA publishes the data on its website. The EPA has also enacted permitting requirements for GHG emissions under the CAA for certain stationary sources and newer modification projects. In March 2014, the White House published the President’s Climate Action Plan Strategy to Reduce Methane Emissions. In August 2015, EPA issued a suite of proposed regulations applicable to the oil and gas sector to decrease methane emissions. There have also been international efforts seeking legally binding reductions in emissions of GHGs. Increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions.

The actions of the EPA and the passage of any federal or state climate change laws or regulations could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

Our operations are subject to governmental laws and regulations relating to the protection of the environment, which may expose us to significant costs and liabilities that could exceed current expectations.

Substantial costs, liabilities, delays and other significant issues could arise from environmental laws and regulations affecting drilling and well completion, gathering, transportation, and storage, and we may incur substantial costs and liabilities in the performance of these types of operations. Our operations are subject to extensive federal, state and local laws and regulations governing environmental protection, the discharge of materials into the environment and the security of chemical and industrial facilities. These laws include:

- Clean Air Act (“CAA”) and analogous state laws, which impose obligations related to air emissions;
- Clean Water Act (“CWA”), and analogous state laws, which regulate discharge of wastewaters and storm water from some our facilities into state and federal waters, including wetlands;
- Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- Resource Conservation and Recovery Act (“RCRA”), and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities;
- National Environmental Policy Act (“NEPA”), which requires federal agencies to study likely environment impacts of a proposed federal action before it is approved, such as drilling on federal lands;
- Safe Drinking Water Act (“SDWA”), which restricts the disposal, treatment or release of water produced or used during oil and gas development;
- Endangered Species Act (“ESA”), and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species; and
- Oil Pollution Act (“OPA”) of 1990, which requires oil storage facilities and vessels to submit to the federal government plans detailing how they will respond to large discharges, requires updates to technology and equipment, regulation of above ground storage tanks and sets forth liability for spills by responsible parties.

Various governmental authorities, including the EPA, the U.S. Department of the Interior, the Bureau of Indian Affairs and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several, strict liability may be incurred without regard to fault under certain environmental laws and regulations, including CERCLA, RCRA and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of oil, natural gas and wastes on, under, or from our properties and facilities. Private parties may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage arising from our operations. Some sites at which we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

In March 2010, the EPA announced its National Enforcement Initiatives for 2011 to 2013, which were extended by the EPA for fiscal years 2014 to 2016, and which include Energy Extraction and “Assuring Energy Extraction Activities Comply with Environmental Laws.” According to the EPA’s website, “some techniques for natural gas extraction pose a significant risk to public health and the environment.” To address these concerns, the EPA’s goal is to “address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment.” This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Our business may be adversely affected by increased costs due to stricter pollution control equipment requirements or liabilities resulting from non-compliance with required operating or other regulatory permits. Also, we might not be able to obtain or maintain from time to time all required environmental regulatory approvals for our operations. If there is a delay in obtaining any required environmental regulatory approvals, or if we fail to obtain and comply with them, the operation or construction of our facilities could be prevented or become subject to additional costs.

We are generally responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with certain acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring certain facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

We make assumptions and develop expectations about possible expenditures related to environmental conditions based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, and new capital costs may be incurred to comply with such changes. In addition, new environmental laws and regulations might adversely affect our products and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions. For instance, the Obama administration issued a suite of proposed regulations to cut methane emissions from the oil and gas sector in August 2015 to petroleum-sector methane emissions 40 to 45 percent by 2025 from 2012 levels. EPA issued its proposed rules for new and modified wells in 2015 and seeks to finalize them in 2016. The Interior Department submitted proposed rules to the Office of Management and Budget in the fall of 2015 aimed at reducing methane flaring at wells on federal land; the Department of Energy is to develop new ways to detect and repair methane leaks; the Department of Transportation is to develop new pipeline safety standards that also reduce leaks. In addition, federal and state agencies could impose additional safety requirements, any of which could affect our profitability.

Legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and additives under pressure into rock formations in order to stimulate natural gas production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs. Recently, there has been heightened debate about the hydraulic fracturing process and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. If adopted, this legislation could establish an additional level of regulation and permitting at the federal, state or local levels, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing. The EPA published its Draft "Assessment of the Potential Impacts of Hydraulic Fracturing for Oil and Gas on Drinking Water Resources" in June 2015 which was released for public comment that closed at the end of 2015. In August 2015, the EPA published its Final 2014 Effluent Guidelines Program Plans under the CWA confirming its intention to regulate wastewater discharges from on-shore unconventional oil and gas extraction and to specifically investigate centralized water treatment facilities that accept oil and gas extraction wastewaters. In addition to the EPA study, the Shale Gas Subcommittee of the Secretary of Energy Advisory Board issued a final report on hydraulic fracturing in November 2011, which includes recommendations to address concerns related to hydraulic fracturing and shale gas production, including but not limited to conducting additional field studies on possible methane leakage from shale gas wells to water reservoirs and adopting new rules and enforcement practices to protect drinking and surface waters.

Several states have adopted or considered legislation requiring the disclosure of fracturing fluids and other restrictions on hydraulic fracturing, including states in which we operate (e.g., Colorado, Texas, North Dakota and New Mexico). Certain organizations have prompted ballot initiatives at the local level that are directed at imposing restrictions on hydraulic fracturing, and such ballot initiatives may be attempted on a wider basis in one or more states where we operate. The U.S. Department of the Interior issued its final rules considering disclosure requirements or other mandates for hydraulic fracturing on federal land, which, if adopted, would affect our operations on federal lands. A federal judge issued an injunction staying implementation of the rules in September 2015 pending hearing on the merits. If new federal or state laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

Our ability to produce gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations, particularly with respect to our Permian Basin, San Juan Basin and Williston Basin operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the EPA prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. In August 2015, the EPA published its Final 2014 Effluent Guidelines Program Plans under the CWA confirming its intention to regulate wastewater discharges from onshore unconventional oil and gas extraction and to specifically investigate centralized water treatment facilities that accept oil and gas extraction wastewaters. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

Legal and regulatory proceedings and investigations relating to the energy industry, and the complex government regulations to which our businesses are subject, have adversely affected our business and may continue to do so. The operation of our businesses might also be adversely affected by changes in regulations or in their interpretation or implementation, or the introduction of new laws, regulations or permitting requirements applicable to our businesses or our customers.

Public and regulatory scrutiny of the energy industry has resulted in increased regulations being either proposed or implemented. Adverse effects may continue as a result of the uncertainty of ongoing inquiries, investigations and court proceedings, or additional inquiries and proceedings by federal or state regulatory agencies or private plaintiffs. In addition, we cannot predict the outcome of any of these inquiries or whether these inquiries will lead to additional legal proceedings against us, civil or criminal fines or penalties, or other regulatory action, including legislation or increased permitting requirements. Current legal proceedings or other matters against us, including environmental matters, suits, regulatory appeals, challenges to our permits by citizen groups and similar matters, might result in adverse decisions against us. The result of such adverse decisions, either individually or in the aggregate, could be material and may not be covered fully or at all by insurance.

In addition, existing regulations might be revised or reinterpreted, new laws, regulations and permitting requirements might be adopted or become applicable to us, our facilities, our customers, our vendors or our service providers, and future changes in laws and regulations could have a material adverse effect on our financial condition, results of operations and cash flows. For example, several ruptures on third-party pipelines have occurred recently. In response, various legislative and regulatory reforms associated with pipeline safety and integrity have been proposed, including new regulations covering gathering pipelines that have not previously been subject to regulation. Such reforms, if adopted, could significantly increase our costs.

Certain of our properties, including our operations in the Williston Basin and San Juan Basin, are located on Native American tribal lands and are subject to various federal and tribal approvals and regulations, which may increase our costs and delay or prevent our efforts to conduct planned operations.

Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, BLM and the Office of Natural Resources Revenue, along with each Native American tribe, promulgate and enforce regulations pertaining to oil and gas operations on Native American tribal lands. These regulations and approval requirements relate to such matters as lease provisions, drilling and production requirements, environmental standards and royalty considerations. In addition, each Native American tribe is a sovereign nation having the right to enforce laws and regulations and to grant approvals independent from federal, state and local statutes and regulations. These tribal laws and regulations include various taxes, fees, requirements to employ Native American tribal members and other conditions that apply to lessees, operators and contractors conducting operations on Native American tribal lands. Lessees and operators conducting operations on tribal lands are generally subject to the Native American tribal court system. In addition, if our relationships with any of the relevant Native American tribes were to deteriorate, we could face significant risks to our ability to continue the projected development of our leases on Native American tribal lands. One or more of these factors may increase our costs of doing business on Native American tribal lands and impact the viability of, or prevent or delay our ability to conduct, our oil or natural gas development and production operations on such lands.

Tax laws and regulations may change over time, including changes to certain federal income tax deductions currently available with respect to oil and gas exploration and production.

Tax laws and regulations are highly complex and subject to interpretation, and the tax laws and regulations to which we are subject may change over time. Our tax filings are based upon our interpretation of the tax laws in effect in various jurisdictions for the periods for which the filings are made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation, it could have a material adverse effect on us.

President Obama has annually proposed changes to certain federal income tax provisions currently available to oil and gas exploration and production companies. Leadership of the House and Senate have also expressed their desire for tax reform. Domestic energy-related changes generally discussed include, but are not limited to, (i) repeal of the percentage depletion allowance for oil and gas properties; (ii) elimination of the ability to fully deduct intangible drilling and development costs in the year incurred; (iii) repeal of the manufacturing deduction for certain U.S. production activities; and (iv) extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. Changes to federal tax deductions, as well as any changes to or the imposition of new state or local taxes (including production, severance, or similar taxes) could negatively affect our financial condition and results of operations.

Our acquisition attempts may not be successful or may result in completed acquisitions that do not perform as anticipated.

We have made and may continue to make acquisitions of businesses and properties. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- some of the acquired businesses or properties may not produce revenues, reserves, earnings or cash flow at anticipated levels or could have environmental, permitting or other problems for which contractual protections prove inadequate;

- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- properties we acquire may be subject to burdens on title that we were not aware of at the time of acquisition or that interfere with our ability to hold the property for production;

- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures; and
- we may issue additional equity or debt securities related to future acquisitions.

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

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

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

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

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

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

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing or undeveloped properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Failure of our service providers or disruptions to our outsourcing relationships might negatively impact our ability to conduct our business.

Some studies indicate a high failure rate of outsourcing relationships. A deterioration in the timeliness or quality of the services performed by the outsourcing providers or a failure of all or part of these relationships could lead to loss of institutional knowledge and interruption of services necessary for us to be able to conduct our business. The expiration of such agreements or the transition of services between providers could lead to similar losses of institutional knowledge or disruptions.

Our assets and operations can be adversely affected by weather and other natural phenomena.

Our assets and operations can be adversely affected by hurricanes, floods, earthquakes, tornadoes and other natural phenomena and weather conditions, including extreme temperatures. Insurance may be inadequate, and in some instances, it may not be available on commercially reasonable terms. A significant disruption in operations or a significant liability for which we were not fully insured could have a material adverse effect on our business, results of operations and financial condition.

Our customers' energy needs vary with weather conditions. To the extent weather conditions are affected by climate change or demand is impacted by regulations associated with climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes, leading either to increased investment or decreased revenues.

Acts of terrorism could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and the assets of our customers and others may be targets of terrorist activities that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to the ability to produce, process, transport or distribute oil, natural gas, or NGLs. Acts of terrorism as well as events occurring in response to or in connection with acts of terrorism could cause environmental repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs.

We entered into a number of agreements with The Williams Companies, Inc. ("Williams") prior to our separation or "spin-off" from that company on December 31, 2011. Our agreements with Williams require us to assume the past, present, and future liabilities related to our business and may be less favorable to us than if they had been negotiated with unaffiliated third parties.

We negotiated all of our agreements with Williams as a wholly-owned subsidiary of Williams. If these agreements had been negotiated with unaffiliated third parties, they might have been more favorable to us. Pursuant to the separation and distribution agreement, we have assumed all past, present and future liabilities (other than tax liabilities which will be governed by the tax sharing agreement as described herein) related to our business, and we will agree to indemnify Williams for these liabilities, among other matters. Such liabilities include unknown liabilities that could be significant. The allocation of assets and liabilities between Williams and us may not reflect the allocation that would have been reached between two unaffiliated parties.

We may increase our debt or raise additional capital in the future, which could affect our financial health, and may decrease our profitability.

We may increase our debt or raise additional capital in the future, subject to restrictions in our debt agreements. If our cash flow from operations is less than we anticipate, or if our cash requirements are more than we expect, we may require more financing. More financing may also be necessary if we are unable to execute dispositions of assets that are underperforming or which are no longer a part of our strategic focus. However, debt or equity financing may not be available to us on terms acceptable to us, if at all. If we incur additional debt or raise equity through the issuance of our preferred stock, the terms of the debt or our preferred stock issued may give the holders rights, preferences and privileges senior to those of holders of our common stock, particularly in the event of liquidation. The terms of the debt may also impose additional and more stringent restrictions on our operations than we currently have. If we raise funds through the issuance of additional equity, your ownership in us would be diluted. If we are unable to raise additional capital when needed, it could affect our financial health, which could negatively affect your investment in us.

We continue to be subject to a tax-sharing agreement with Williams.

Prior to our spin-off from Williams on December 31, 2011, Williams received an opinion of its outside tax advisor as well as a private letter ruling from the IRS holding that the spin-off will not result in the recognition, for federal income tax purposes, of income, gain or loss to Williams and Williams’ stockholders. Under the tax sharing agreement with Williams that we executed as part of the spin-off, we are required to indemnify Williams against tax-related liabilities that may be incurred by Williams relating to the spin-off, to the extent caused by a breach of any representations or covenants we made with respect to the spin-off and relied upon in the tax opinion or private letter ruling. The IRS is currently auditing Williams' 2011 consolidated federal income tax return that includes the spin-off.

For any tax periods ending on or before the spin-off, we and our U.S. subsidiaries were included in Williams' consolidated group for federal income tax purposes. Under the tax sharing agreement with Williams, for each period in which we were consolidated with Williams for purposes of any tax return, a pro forma tax return was prepared for us as if we filed our own consolidated return. 2011 is the only open federal tax period for which we are still subject to the tax sharing agreement with Williams. For any adjustments to the 2011 pro forma tax return we will reimburse Williams for any additional taxes shown on the pro forma tax return, and Williams will reimburse us for reductions in the taxes shown on the pro forma tax return. We also have deferred tax assets that Williams was required to allocate to us by the Internal Revenue Code that could decrease or increase due to adjustments that change those allocations, whether or not related to our business. Williams effectively controls all tax decisions in connection with their 2011 consolidated income tax return. Thus Williams will be able to choose whether to contest, compromise or settle any adjustment or deficiency proposed by the relevant taxing authority in a manner that may be beneficial to Williams and detrimental to us.

Third parties may seek to hold us responsible for liabilities of Williams that we did not assume in our agreements.

Third parties may seek to hold us responsible for retained liabilities of Williams. Under our agreements with Williams, Williams agreed to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure you that we will be able to recover the full amount of our losses from Williams.

Our prior and continuing relationship with Williams exposes us to risks attributable to businesses of Williams.

Williams is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of Williams that are incurred through a breach of the separation and distribution agreement or any ancillary agreement by Williams or its affiliates other than us, or losses that are attributable to Williams in connection with the spin-off or are not expressly assumed by us under our agreements with Williams. Any claims made against us that are properly attributable to Williams in accordance with these arrangements would require us to exercise our rights under our agreements with Williams to obtain payment from Williams. We are exposed to the risk that, in these circumstances, Williams cannot, or will not, make the required payment.

Risks Related to Our Common Stock

Future issuances of our common stock may depress the price of our common stock.

In the future, we may issue our securities in connection with investments or acquisitions. The amount of shares of our common stock issued in connection with an investment or acquisition could constitute a material portion of our then outstanding shares of our common stock.

We do not anticipate paying any dividends on our common stock in the foreseeable future. As a result, you will need to sell your shares of common stock to receive any income or realize a return on your investment.

We do not anticipate paying any dividends on our common stock in the foreseeable future. Any declaration and payment of future dividends to holders of our common stock may be limited by the provisions of the Delaware General Corporation Law ("DGCL"). The future payment of dividends will be at the sole discretion of our Board of Directors and will depend on many factors, including our earnings, capital requirements, financial condition and other considerations that our Board of Directors deems relevant. As a result, to receive any income or realize a return on your investment, you will need to sell your shares of common stock. You may not be able to sell your shares of common stock at or above the price you paid for them.

Provisions of Delaware law and our charter documents may delay or prevent an acquisition of us that stockholders may consider favorable or may prevent efforts by our stockholders to change our directors or our management, which could decrease the value of your shares.

Section 203 of the DGCL and provisions in our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire us without the consent of our Board of Directors. These provisions include the following:

- restrictions on business combinations for a three-year period with a stockholder who becomes the beneficial owner of more than 15 percent of our common stock;
- restrictions on the ability of our stockholders to remove directors; and

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- supermajority voting requirements for stockholders to amend our organizational documents.

Although we believe these provisions protect our stockholders from coercive or otherwise unfair takeover tactics and thereby provide an opportunity to receive a higher bid by requiring potential acquirers to negotiate with our Board of Directors, these provisions apply even if the offer may be considered beneficial by some stockholders. Further, these provisions may discourage potential acquisition proposals and may delay, deter or prevent a change of control of our company, including through unsolicited transactions that some or all of our stockholders might consider to be desirable. As a result, efforts by our stockholders to change our directors or our management may be unsuccessful.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Information regarding our properties is included in Item 1 of this report.

Item 3. Legal Proceedings

See Item 8—Financial Statements and Supplementary Data—Note 10 of our Notes to Consolidated Financial Statements for the information that is called for by this item.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the New York Stock Exchange under the ticker symbol “WPX.” The following table sets forth, for the periods indicated, the high and low sales prices per share of our common stock as reported by the New York Stock Exchange.

	Years Ended December 31,			
	2015		2014	
	High	Low	High	Low
Common Stock:				
Fourth quarter	$9.20	$5.03	$24.42	$10.01
Third quarter	$12.39	$5.24	$26.79	$20.05
Second quarter	$14.65	$10.95	$24.35	$17.97
First quarter	$13.55	$10.04	$20.55	$16.80

At February 24, 2016, there were 7,671 holders of record of our common stock.

We have not paid or declared any cash dividends on our common stock. Any decision as to future payment of dividends is subject to the discretion of our Board of Directors.

Stockholder Return Performance Presentation

The following stock performance graph and related information shall not be deemed “soliciting material” or to be “filed” with the United States Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or Securities Exchange Act of 1934, as amended, except to the extent that WPX specifically requests that such information be treated as “soliciting material” or specifically incorporates such information by reference into such a filing.

The performance graph below compares the cumulative four-year total return to stockholders on WPX's common stock as compared to the cumulative four-year total returns on the Standard and Poor's Midcap 400 Index (“MID”), the NYSE ARCA Natural Gas Index (“XNG”) and the SIG Oil Exploration and Production Index (“EPX”). The comparison assumed a $100 investment was made in WPX's stock, the MID Index, the XNG Index and the EPX index as of December 31, 2011. WPX's common stock began trading on the NYSE on December 12, 2011.

	As of December 31,				
Total Return Analysis data:	2011	2012	2013	2014	2015
WPX	$100.00	$82.21	$112.60	$64.25	$31.71
MID	$100.00	$116.07	$152.71	$165.21	$159.08
XNG	$100.00	$102.19	$128.45	$114.34	$68.40
EPX	$100.00	$88.48	$111.10	$79.06	$43.02

Item 6. Selected Financial Data

The following financial data at December 31, 2015 and 2014, and for each of the three years in the period ended December 31, 2015, 2014 and 2013 should be read in conjunction with the other financial information included in Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Part II, Item 8, Financial Statements and Supplementary Data of this Form 10-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	$1,888	$3,493	$2,431	$2,900	$3,531
Income (loss) from continuing operations(a)	$(1,639)	$129	$(1,104)	$(174)	$106
Income (loss) from discontinued operations(b)	(87)	42	(87)	(37)	(398)
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	$(1,648)	$129	$(1,092)	$(174)	$106
Income (loss) from discontinued operations	$(88)	$35	$(93)	$(49)	$(408)
Basic earnings (loss) per common share:					
Income (loss) from continuing operations	(7.04)	0.63	(5.45)	(0.87)	0.54
Income (loss) from discontinued operations	(0.38)	0.18	(0.46)	(0.25)	(2.07)
Diluted earnings (loss) per common share:					
Income (loss) from continuing operations	(7.04)	0.62	(5.45)	(0.87)	0.54
Income (loss) from discontinued operations	(0.38)	0.18	(0.46)	(0.25)	(2.07)

	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	$8,350	$8,778	$8,413	$9,438	$10,411
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

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(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	$2,308	$20	$860	$123	$—
Impairment of unproved leasehold property	$26	$41	$317	$—	$—
Impairment of equity method investment	$—	$—	$20	$—	$—
Impairment of exploratory area well costs and dry hole costs	$24	$88	$3	$1	$61
Net (gain) loss on sales of assets	$(349)	$196	$—	$—	$—

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

	Years Ended December 31,				
	2015	2014	2013	2012	2011
	(Millions)				
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)	$—	$—

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. Our other areas of operations include natural gas plays in the Piceance Basin of the Rocky Mountain region and 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.

On February 9, 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. WPX Energy Rocky Mountain LLC holds our Piceance Basin operations. The agreement requires Terra to assume approximately $100 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. The parties expect to close the sale in the second quarter of 2016 (see Note 16 of Notes to Consolidated Financial Statements).

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.

The following discussion should be read in conjunction with the selected historical consolidated financial data and the consolidated financial statements and the related notes included in Part II, Item 8 in this Form 10-K. The matters discussed below may contain forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward looking statements. Factors that could cause or contribute to these differences include, but are not limited to, those discussed below and elsewhere in this Form 10-K, particularly in "Risk Factors" and "Forward-Looking Statements."

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.

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)	13,010	9,244	5,919
Natural gas (MMcf)	247,389	280,386	295,934
NGLs (MBbls)	7,289	6,250	7,415
Combined equivalent volumes (Mboe)(b)(c)	61,530	62,225	62,657
Combined equivalent volumes (MMcfe)(b)(c)	369,181	373,352	375,940
Production Sales Volume Per Day(a):			
Oil (MBbls/d)	35.6	25.3	16.2
Natural Gas (MMcf/d)	678	768	811
NGL (MBbls/d)	20.0	17.1	20.3
Combined equivalent volumes (Mboe/d)(c)	168.6	170.5	171.7
Combined equivalent volumes (MMcfe/d)(c)	1,011	1,023	1,030
Financial Data (millions):			
Total revenues	$1,888	$3,493	$2,431
Operating income (loss)	$(2,300)	$326	$(1,601)
Cash capital expenditures(d)	$(1,124)	$(1,807)	$(1,154)
Cash expenditure activity(d)	$(865)	$(1,934)	$(1,207)

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(a) Excludes production from our discontinued operations.

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

(c) Production volumes associated with our Piceance Basin are presented below:

	Years Ended December 31,		
	2015	2014	2013
Production Sales Volume Data:			
Combined equivalent volumes (Mboe)	35,608	40,337	44,206
Combined equivalent volumes (MMcfe)	213,646	242,023	265,233
Production Sales Volume Per Day:			
Combined equivalent volumes (Mboe/d)	97.6	110.5	121.1
Combined equivalent volumes (MMcfe/d)	585	663	727

(d) Includes capital expenditures related to discontinued operations of $18 million, $96 million and $46 million for the years ended December 31, 2015, 2014 and 2013, respectively, and excludes capital expenditures related to acquisitions.

Our 2015 operating results were $2.6 billion unfavorable compared to 2014. The primary unfavorable impacts include a $2.3 billion impairment of our Piceance Basin properties (see Note 5 of Notes to Consolidated Financial Statements), $758 million lower production revenues and $130 million higher depreciation, depletion and amortization expense. 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) while 2014 included a $196 million loss on the sale of a portion of our working interests in the Piceance Basin and $143 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 $1.9 billion favorable compared to 2013. Favorable impacts include a $558 million favorable change in derivatives not designated as hedges, a $250 million decrease in exploration expenses (including exploratory well costs and unproved leasehold impairments), $190 million higher oil and condensate sales and $106 million higher natural gas sales. Additionally, impairments of proved producing properties were $20 million in 2014 as compared to impairments of proved producing properties and capitalized cost of acquired unproved reserves of $860 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 has signed an agreement for the disposition of all of its assets in the Piceance Basin for $910 million. These targeted divestitures will provide proceeds to reduce our debt and/or provide cash for liquidity. Through the date of this filing, we have 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. 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 $1.2 billion (including the Piceance Basin). 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	412	$3.63	93	$3.22
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 will novate fixed price Henry Hub swaps totaling 265 BBtu per day in April-December 2016 at a weighted average price of $3.463 per MMBtu. WPX will also novate all 2017 fixed price Henry Hub swaps noted in the table above. In addition to the hedges in the table above, WPX Rocky Mountain, LLC has 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. These hedges are also expected to be assigned to the buyer at close of the Piceance sale.

Results of Operations

Operations of our company include oil, natural gas and NGL development, production and gas management activities primarily located in Colorado, New Mexico, North Dakota and Texas. Our development and production techniques specialize in production from tight-sands and shale formations primarily in the Permian, Williston, San Juan and Piceance 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,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2015	2014		
	(Millions)			
Revenues:				
Oil and condensate sales	$514	$724	$(210)	(29)%
Natural gas sales	563	1,002	(439)	(44)%
Natural gas liquid sales	96	205	(109)	(53)%
Total product revenues	1,173	1,931	(758)	(39)%
Gas management	288	1,120	(832)	(74)%
Net gain (loss) on derivatives not designated as hedges	418	434	(16)	(4)%
Other	9	8	1	13%
Total revenues	$1,888	$3,493	$(1,605)	(46)%

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

- $210 million decrease in oil and condensate sales reflects $504 million related to lower sales prices partially offset by a $294 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	2014
Oil sales (per barrel)	$ 39.55	$ 78.32
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	29.94	2.01
Oil net price including all derivative settlements (per barrel)	$ 69.49	$ 80.33
Oil and condensate production sales volumes (Mbbls)	13,010	9,244
Per day oil and condensate production sales volumes (Mbbls/d)	35.6	25.3

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

- $439 million decrease in natural gas sales is primarily due to $321 million related to lower sales prices and $118 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 sales of Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during second-quarter 2014 (see Note 5 of Notes to Consolidated Financial Statements). Natural gas production from the Piceance Basin represents approximately 73 percent of our total natural gas production. 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)	$ 2.27	$ 3.57
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(a)	1.05	(0.10)
Natural gas net price including all derivative settlements (per Mcf)	$ 3.32	$ 3.47
Natural gas production sales volumes (MMcf)	247,389	280,386
Per day natural gas production sales volumes (MMcf/d)	678	768

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

- $109 million decrease in natural gas liquids sales is primarily due to $143 million related to lower NGL sales prices partially offset by $34 million higher production sales volumes 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)	$ 13.23	$ 32.79
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	—	1.12
NGL net price including all derivative settlements (per barrel)	$ 13.23	$ 33.91
NGL production sales volumes (Mbbls)	7,289	6,250
Per day NGL production sales volumes (Mbbls/d)	20.0	17.1

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

The following table summarizes the composition of the Piceance NGL barrel for 2015 and 2014.

	Years ended December 31,			
	2015		2014	
	% of barrel	$/gallon	% of barrel	$/gallon
Ethane	32 %	$0.20	29 %	$0.28
Propane	32 %	$0.46	33 %	$1.05
Iso-Butane	9 %	$0.62	10 %	$1.25
Normal Butane	8 %	$0.61	8 %	$1.22
Natural Gasoline	19 %	$1.08	20 %	$1.99

- $832 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 $725 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 anticipated closing of the Piceance divestiture, approximately $82 million of our net derivative assets as of December 31, 2015 will be assigned to the buyer.

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	$220	$244	$24	10 %
Gathering, processing and transportation	282	328	46	14 %
Taxes other than income	75	126	51	40 %
Gas management, including charges for unutilized pipeline capacity	262	987	725	73 %
Exploration	111	173	62	36 %
Depreciation, depletion and amortization	940	810	(130)	(16)%
Impairment of producing properties and costs of acquired unproved reserves	2,308	20	(2,288)	NM
Net (gain) loss on sales of assets	(349)	196	545	NM
General and administrative	249	271	22	8 %
Acquisition costs	23	—	(23)	NM
Other—net	67	12	(55)	NM
Total costs and expenses	$4,188	$3,167	$(1,021)	(32)%
Operating income (loss)	$(2,300)	$326	$(2,626)	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:

- $24 million decrease in lease and facility operating expenses primarily relates to lower natural gas volumes due to the sales of a portion of our Appalachian Basin assets in the first quarter of 2015 and a portion of our working interests in the Piceance Basin during the second-quarter 2014, as well as cost reduction efforts across our basins. This decrease is partially offset by higher oil production volumes and approximately $25 million related to the Permian Basin since the Acquisition date. Lease and facility operating expense in 2015 averaged $3.58 per Boe compared to $3.92 per Boe during 2014.
- $46 million decrease in gathering, processing and transportation expenses primarily relates to lower natural gas volumes. Additionally, during 2014, we recognized approximately $5 million related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company. Also included in gathering, processing and transportation expenses are $8 million and $13 million in 2015 and 2014, respectively, of excess gathering capacity expense. Gathering, processing and transportation charges averaged $4.59 per Boe for 2015 and $5.28 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.
- $51 million decrease in taxes other than income primarily relates to lower commodity prices and decreased natural gas production volumes, partially offset by higher oil production volumes. Our taxes other than income averaged $1.23 per Boe for 2015 compared to an average of $2.02 per Boe for 2014.
- $725 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.

- $62 million decrease in exploration expenses primarily relates to the absence of a $67 million impairment of well costs related to our Niobrara Shale in the Piceance Basin. Impairments of exploratory area leasehold and well

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costs in non-core exploratory plays for which management no longer intends to continue exploratory activities were similar in 2015 and 2014 (see Note 5 of Notes to Consolidated Financial Statements).

- $130 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 the fact that we have adjusted the proved reserves used for the calculation of depletion and amortization to reflect the impact of a decrease in the 12-month average price resulting in a $71 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 $15.27 per Boe compared to an average $13.02 per Boe in 2014.
- $2,308 million of property impairments in 2015 compared to $20 million in 2014 (see Note 5 of Notes to Consolidated Financial Statements).
- $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. Net (gain) loss on sales of assets in 2014 reflects a $196 million loss on the sale of a portion of our working interests in certain Piceance Basin wells (see Note 5 of Notes to Consolidated Financial Statements).
- $22 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 $4.05 per Boe for 2015 compared to $4.35 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 $3.80 per Boe for 2015 and $4.19 per Boe for 2014.
- $23 million of acquisition costs in 2015 related to the Acquisition (See Note 2 of Notes to Consolidated Financial Statements).
- $55 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, 2015	2014	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$(2,300)	$326	$(2,626)	NM
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	(2,554)	204	(2,758)	NM
Provision (benefit) for income taxes	(915)	75	990	NM
Income (loss) from continuing operations	(1,639)	129	(1,768)	NM
Income (loss) from discontinued operations	(87)	42	(129)	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 a loss from continuing operations before income taxes in 2015 compared to income from continuing operations before income taxes in 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 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,		Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	2014	2013		
	(Millions)			
Revenues:				
Oil and condensate sales	$724	$534	$190	36 %
Natural gas sales	1,002	896	106	12 %
Natural gas liquid sales	205	228	(23)	(10)%
Total product revenues	1,931	1,658	273	16 %
Gas management	1,120	891	229	26 %
Net gain (loss) on derivatives not designated as hedges	434	(124)	558	NM
Other	8	6	2	33 %
Total revenues	$3,493	$2,431	$1,062	44 %

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

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

- $190 million increase in oil and condensate sales reflects a $300 million increase related to production sales volumes for 2014 compared to 2013 partially offset by a $110 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	2013
Oil sales (per barrel)	$ 78.32	$ 90.21
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	2.01	1.52
Oil net price including all derivative settlements (per barrel)	$ 80.33	$ 91.73

Oil and condensate production sales volumes (Mbbls)	9,244	5,919
Per day oil and condensate production sales volumes (Mbbls/d)	25.3	16.2

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

- $106 million increase in natural gas sales primarily reflects $157 million related to higher natural gas prices partially offset by a $47 million decrease related to lower production sales volumes for 2014 compared to 2013. The decrease in our production sales volumes is primarily due to the impact of the sale of a portion of our working interests to Legacy during second-quarter 2014 (see Note 5 of Notes to Consolidated Financial Statements). Natural gas production from the Piceance Basin represents approximately 73 percent of our total domestic natural gas production. The following table reflects natural gas production prices and volumes for 2014 and 2013.

	Years ended December 31, 2014	2013
Natural gas sales (per Mcf)(a)	$ 3.57	$ 3.03
Impact of net cash received (paid) related to settlement of derivatives (per Mcf)(b)	(0.10)	(0.07)
Natural gas net price including all derivative settlements (per Mcf)	$ 3.47	$ 2.96
Natural gas production sales volumes (MMcf)	280,386	295,934
Per day natural gas production sales volumes (MMcf/d)	768	811

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(a) Includes $0.02 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.

- $23 million decrease in natural gas liquids sales reflects decreased production sales volumes despite a higher price per barrel for 2014 compared to 2013. The increased average barrel price for natural gas liquids partially reflects a change in the composition of the barrel, as noted in the table below, due to lower ethane recovery rates. The following table reflects natural gas liquid production prices and volumes for 2014 and 2013.

	Years ended December 31, 2014	2013
NGL sales (per barrel)	$ 32.79	$ 30.72
Impact of net cash received (paid) related to settlement of derivatives (per barrel)(a)	1.12	0.08
NGL net price including all derivative settlements (per barrel)	$ 33.91	$ 30.80
NGL production sales volumes (Mbbls)	6,250	7,415
Per day NGL production sales volumes (Mbbls/d)	17.1	20.3

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(a) Included in net gain (loss) on derivatives not designated as hedges on the Consolidated Statements of Operations.
The following table summarizes the composition of the Piceance NGL barrel for 2014 and 2013.

	Years ended December 31, 2014 % of barrel	$/gallon	2013 % of barrel	$/gallon
Ethane	29 %	$0.28	39 %	$0.25
Propane	33 %	$1.05	29 %	$0.98
Iso-Butane	10 %	$1.25	8 %	$1.41
Normal Butane	8 %	$1.22	7 %	$1.38
Natural Gasoline	20 %	$1.99	17 %	$2.11

- $229 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

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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 $56 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	$244	$227	$(17)	(7)%
Gathering, processing and transportation	328	350	22	6%
Taxes other than income	126	102	(24)	(24)%
Gas management, including charges for unutilized pipeline capacity	987	931	(56)	(6)%
Exploration	173	423	250	59%
Depreciation, depletion and amortization	810	858	48	6%
Impairment of producing properties and costs of acquired unproved reserves	20	860	840	98%
Loss on sale of working interests in the Piceance Basin	196	—	(196)	NM
General and administrative	271	269	(2)	(1)%
Other—net	12	12	—	—%
Total costs and expenses	$3,167	$4,032	$865	21%
Operating income (loss)	$326	$(1,601)	$1,927	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:

- $17 million increase in lease and facility operating expenses primarily relates to the impact of increased oil production in the Williston and San Juan Basins in relation to our overall portfolio. Lease and facility operating expense in 2014 averaged $3.92 per Boe compared to $3.63 per Boe during 2013.
- $22 million decrease in gathering, processing and transportation expenses primarily related to lower natural gas and NGL volumes and approximately $5 million recognized during 2014 related to a tariff rate refund received in prior years which is no longer under appeal by the pipeline company. 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 $5.28 per Boe for 2014 and $5.60 per Boe for 2013. Excluding the impact of the refund, the gathering, processing and transportation expenses would have averaged $5.35 per Boe for 2014.
- $24 million increase in taxes other than income primarily relates to increased oil production volumes and higher natural gas prices. Our taxes other than income averaged $2.02 per Boe for 2014 compared to an average of $1.63 per Boe for 2013.
- $56 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.

- $250 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 a $67 million impairment related to our Niobrara Shale in the Piceance Basin and $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).
- $48 million decrease in depreciation, depletion and amortization expenses primarily due to the previously discussed lower natural gas production volumes and the impact of impairments taken in 2013 in the Appalachian Basin partially offset by the increase in oil production. During 2014, our depreciation, depletion and amortization averaged $13.02 per Boe compared to an average $13.69 per Boe in 2013.
- $20 million of property impairments in 2014 compared to $860 million in 2013 (see Note 5 of Notes to Consolidated Financial Statements).
- $196 million loss on the sale of a portion of our working interests in certain Piceance Basin wells (see Note 5 of Notes to Consolidated Financial Statements).
- General and administrative expenses were relatively flat in 2014 compared to 2013. Included in 2014 is $10 million related to a voluntary early exit program.
- 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	2013	Favorable (Unfavorable) $ Change	Favorable (Unfavorable) % Change
	(Millions)			
Operating income (loss)	$326	$(1,601)	$1,927	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	204	(1,728)	1,932	NM
Provision (benefit) for income taxes	75	(624)	(699)	NM
Income (loss) from continuing operations	129	(1,104)	1,233	NM
Income (loss) from discontinued operations	42	(87)	129	NM
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

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

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 Powder River Basin and our former international segment (see Note 3 of Notes to Consolidated Financial Statements).

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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 $370 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. Subsequent to December 31, 2015, we have borrowed an additional $110 million on our revolving credit facility. Also subsequent to December 31, 2015, we have repurchased $51 million of long-term notes due in 2017.

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.

We have three bilateral, uncommitted letter of credit agreements which we anticipate will be renewed annually. These agreements allow us to preserve our liquidity under our Credit Facility while providing support to our ability to meet performance obligation needs for, among other items, various interstate pipeline contracts into which we have entered. These unsecured agreements incorporate similar terms as those in the Credit Facility. At December 31, 2015, a total of $233 million in letters of credit have been issued.

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. The ratings as of the date of this filing are as follows:

Standard and Poor's(a)	
Corporate Credit Rating	BB-
Senior Unsecured Debt Rating	BB-
Outlook	Negative
Moody's Investors Service(b)	
Senior Unsecured Debt Rating	B2
LT Corporate Family 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 $15 million, $130 million and $92 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. Capital expenditures incurred for drilling and completions totaled $733 million, $1.5 billion and $1.0 billion 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 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 which the purchaser of our Piceance Basin operations will assume (see Note 16 of Notes to Consolidated Financial Statements).

(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 16 of Notes to Consolidated Financial Statements). Excluded are liabilities associated with asset retirement obligations totaling $237 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 5 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

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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 $83 million and $102 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, 85 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 $426 million and $493 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

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.

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 Annual Report on Form 10-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 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Tulsa, Oklahoma
February 25, 2016

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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 the Index at Item 15.(a).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

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	312	459
Derivative assets	376	498
Inventories	59	45
Margin deposits	1	27
Assets classified as held for sale	40	773
Other	24	26
Total current assets	850	1,869
Properties and equipment, net (successful efforts method of accounting)	7,401	6,842
Derivative assets	65	38
Other noncurrent assets	34	29
Total assets	$8,350	$8,778
Liabilities and Equity		
Current liabilities:		
Accounts payable	$328	$712
Accrued and other current liabilities	349	177
Liabilities associated with assets held for sale	—	132
Deferred income taxes (Note 1)	—	151
Derivative liabilities	13	37
Total current liabilities	690	1,209
Deferred income taxes	465	621
Long-term debt, net	3,189	2,260
Derivative liabilities	2	5
Asset retirement obligations	232	198
Other noncurrent liabilities	237	57
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	$8,350	$8,778

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 and condensate sales	$514	$724	$534
Natural gas sales	563	1,002	896
Natural gas liquid sales	96	205	228
Total product revenues	1,173	1,931	1,658
Gas management	288	1,120	891
Net gain (loss) on derivatives not designated as hedges (Note 15)	418	434	(124)
Other	9	8	6
Total revenues	1,888	3,493	2,431
Costs and expenses:			
Lease and facility operating	220	244	227
Gathering, processing and transportation	282	328	350
Taxes other than income	75	126	102
Gas management, including charges for unutilized pipeline capacity (Note 5)	262	987	931
Exploration (Note 5)	111	173	423
Depreciation, depletion and amortization	940	810	858
Impairment of producing properties and costs of acquired unproved reserves (Note 5)	2,308	20	860
Net (gain) loss on sales of assets (Note 5)	(349)	196	—
General and administrative	249	271	269
Acquisition costs (Note 2)	23	—	—
Other—net	67	12	12
Total costs and expenses	4,188	3,167	4,032
Operating income (loss)	(2,300)	326	(1,601)
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	(2,554)	204	(1,728)
Provision (benefit) for income taxes	(915)	75	(624)
Income (loss) from continuing operations	(1,639)	129	(1,104)
Income (loss) from discontinued operations	(87)	42	(87)
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	$(1,648)	$129	$(1,092)
Income (loss) from discontinued operations	(88)	35	(93)
Net income (loss)	$(1,736)	$164	$(1,185)
Basic earnings (loss) per common share (Note 4):			
Income (loss) from continuing operations	$(7.04)	$0.63	$(5.45)
Income (loss) from discontinued operations	(0.38)	0.18	(0.46)
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	$(7.04)	$0.62	$(5.45)
Income (loss) from discontinued operations	(0.38)	0.18	(0.46)
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.

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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

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(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(a):			
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	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	(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) Includes amounts related to 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.

WPX Energy, Inc.
Notes to Consolidated Financial Statements
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 Colorado, New Mexico, North Dakota and Texas in the United States. We specialize in development and production from tight-sands and shale formations in the Piceance, Williston and San Juan Basins and we have recently entered the core of the Permian's Delaware Basin through our acquisition of RKI Exploration & Production, LLC (“RKI”). See Note 2 for additional information regarding this acquisition. We also have operations and interests in the Appalachian and Green River Basins located in Pennsylvania and Wyoming. Associated with our commodity production are sales and marketing activities, referred to as gas management activities, that include the management of various commodity contracts such as transportation and related derivatives coupled with the sale of our commodity volumes.
In addition, we had operations in the Powder River Basin in Wyoming which were sold on September 1, 2015 and, until January 29, 2015, we had a 69 percent controlling interest in Apco Oil and Gas International Inc. (“Apco”), an oil and gas exploration and production company with activities in Argentina and Colombia. For all periods presented, the results of Powder River Basin and Apco are reported as discontinued operations.
The consolidated businesses represented herein as WPX Energy, Inc., also referred to herein as “WPX” or the “Company,” is at times referred to in the first person as “we,” “us” or “our.”
Basis of Presentation
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 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.

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

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	$57	$43
Crude oil production in transit	2	2
	$59	$45

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.

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

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.

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

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, condensate and 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.

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

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	$2,100	$3,875
Net income (loss) from continuing operations attributable to WPX Energy, Inc.	$(1,554)	$151

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).

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

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

	Purchase Price Allocation (Millions)
Consideration:	
Cash, 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

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(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

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

Note 3. Discontinued Operations

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

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.

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.

Summarized Results of Discontinued Operations

For the year ended December 31, 2015	Powder River Basin	International	Total
		(Millions)	
Total revenues	$55	$15	$70
Costs and expenses:			
Lease and facility operating	$24	$4	$28
Gathering, processing and transportation	39	—	39
Taxes other than income	5	3	8
Accrual for contract obligations retained and related accretion	190	—	190
Impairment of assets held for sale	16	—	16
General and administrative	5	1	6
Other—net	(14)	—	(14)
Total costs and expenses	265	8	273
Operating income (loss)	(210)	7	(203)
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	(220)	49	(171)
Provision (benefit) for income taxes	(81)	(3)	(84)
Income (loss) from discontinued operations	$(139)	$52	$(87)

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

For the year ended December 31, 2014	Powder River Basin	International	Total
		(Millions)	
Total revenues	$189	$163	$352
Costs and expenses:			
Lease and facility operating	$41	$37	$78
Gathering, processing and transportation	70	1	71
Taxes other than income	16	28	44
Exploration	—	4	4
Depreciation, depletion and amortization	11	42	53
Impairment of producing properties and costs of acquired unproved reserves	45	—	45
General and administrative	4	16	20
Other—net	—	12	12
Total costs and expenses	187	140	327
Operating income (loss)	2	23	25
Interest capitalized	1	—	1
Investment income and other	6	19	25
Income (loss) from discontinued operations before income taxes	9	42	51
Provision (benefit) for income taxes(a)	2	7	9
Income (loss) from discontinued operations	$7	$35	$42

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(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	Powder River Basin	International	Total
		(Millions)	
Total revenues	$178	$152	$330
Costs and expenses:			
Lease and facility operating	$44	$37	$81
Gathering, processing and transportation	80	3	83
Taxes other than income	15	24	39
Exploration	1	7	8
Depreciation, depletion and amortization	48	34	82
Impairment of producing properties and costs of acquired unproved reserves	192	3	195
Gain on sale of Powder River Basin deep rights leasehold	(36)	—	(36)
General and administrative	6	14	20
Other—net	5	—	5
Total costs and expenses	355	122	477
Operating income (loss)	(177)	30	(147)
Interest capitalized	4	—	4
Investment income and other	4	21	25
Income (loss) from discontinued operations before income taxes	(169)	51	(118)
Provision (benefit) for income taxes(a)	(62)	31	(31)
Income (loss) from discontinued operations	$(107)	$20	$(87)

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(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.

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

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

December 31, 2014	Powder River Basin	International	Total
		(Millions)	
Assets classified as held for sale			
Current assets:			
Cash and cash equivalents	$—	$29	$29
Accounts receivable	—	25	25
Inventories	1	7	8
Other	—	14	14
Total current assets	1	75	76
Investments	18	134	152
Properties and equipment (successful efforts method of accounting)(a)	132	445	577
Less—accumulated depreciation, depletion and amortization	(10)	(228)	(238)
Properties and equipment, net	122	217	339
Other noncurrent assets	—	6	6
Total assets classified as held for sale—discontinued operations	$141	$432	$573
Total assets classified as held for sale—continuing operations (Note 5)	200	—	200
Total assets classified as held for sale on the Consolidated Balance Sheets	$341	$432	$773
Liabilities associated with assets held for sale			
Current liabilities:			
Accounts payable	$—	$34	$34
Accrued and other current liabilities	3	23	26
Total current liabilities	3	57	60
Deferred income taxes	—	13	13
Long-term debt	—	2	2
Asset retirement obligations	45	7	52
Other noncurrent liabilities	—	3	3
Total liabilities associated with assets held for sale—discontinued operations	$48	$82	$130
Total liabilities associated with assets held for sale—continuing operations (Note 4)	$2	$—	$2
Total liabilities associated with assets held for sale on the Consolidated Balance Sheets	$50	$82	$132

(a) Powder River Basin includes $45 million impairment 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.

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

Cash Flows Attributable to Discontinued Operations
Excluding taxes and changes to working capital related to Powder River Basin, total cash provided by operating activities related to discontinued operations was $12 million, $65 million and $36 million for 2015, 2014 and 2013, respectively. Total cash used in investing activities related to Powder River Basin discontinued operations was $3 million, $11 million and $3 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.	$(1,639)	$129	$(1,092)
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	$(1,648)	$129	$(1,092)
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	$(7.04)	$0.63	$(5.45)
Diluted	$(7.04)	$0.62	$(5.45)

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(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.

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

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

In 2015, 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 Consolidated Statements of Operations and $26 million is included in exploration expenses. In 2014, we recorded a total of $87 million in impairment charges associated with exploratory well costs and producing properties of which approximately $20 million is recorded as a separate line on the Consolidated Statements of Operations and $67 million is included in exploration expenses. In 2013, we recorded a total of $1.2 billion in impairment charges of which $860 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.

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.

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

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)	$2,308	$20	$860
Impairment of equity method investment in Appalachian Basin	$—	$—	$20

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

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 $2,308 million impairment in the fourth quarter of 2015 in the Piceance Basin.

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
- $9 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 the following impairments during 2013:

- $772 million impairment in the fourth quarter of proved producing oil and gas properties in the Appalachian Basin; and
- $88 million impairment 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.

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.

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

Exploration Expenses
The following table presents a summary of exploration expenses.

	Years Ended December 31,		
	2015	2014	2013
	(Millions)		
Geologic and geophysical costs	$7	$11	$18
Impairments of exploratory area well costs and dry hole costs	24	88	3
Unproved leasehold property impairments, amortization and expiration	80	74	402
Total exploration expenses	$111	$173	$423

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 $67 million of impairment related to our Niobrara Shale well costs in the Piceance Basin and $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. The $67 million Niobrara Shale impairment relates to carrying costs on producing and science wells in excess of estimated discounted cash flows of the exploratory play.
Unproved leasehold property impairments, amortization and expiration in 2015 includes impairments of $26 million related to unproved leasehold costs in the Piceance Basin and $26 million related to a non-core exploratory play where we no longer intend to continue exploration activities. The $26 million impairment of Piceance Basin leasehold costs was recorded in connection with the impairment of the proved properties previously discussed. 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	2014
		(Millions)	
Proved properties	(b)	$6,315	$10,386
Unproved properties	(c)	2,355	394
Gathering, processing and other facilities	15-25	258	251
Construction in progress	(c)	218	541
Other	3-40	148	181
Total properties and equipment, at cost		9,294	11,753
Accumulated depreciation, depletion and amortization		(1,893)	(4,911)
Properties and equipment—net		$7,401	$6,842

(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.

We recorded a $2.3 billion impairment of the Piceance Basin properties which is reflected in the amounts as of December 31, 2015. 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

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

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.

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

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	$201	$308
Liabilities incurred	28	19
Liabilities settled	(2)	(2)
Liabilities associated with assets sold	—	(65)
Estimate revisions	(4)	(78)
Accretion expense(a)	13	19
Balance, December 31(b)	$236	$201
Amount reflected as current	$4	$3

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

(b) Asset retirement obligations for our Piceance Basin assets were approximately $133 million as of December 31, 2015.

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	2014
	(Millions)	
Trade	$125	$215
Accrual for capital expenditures	70	313
Royalties	103	125
Other	30	59
	$328	$712

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	2014
	(Millions)	
Taxes other than income taxes	$71	$41
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	30	12
	$349	$177

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)	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, we have repurchased $51 million of long-term notes due in 2017.

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

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

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. 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.

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)	$(3)	$(29)
State	7	1	1
	3	(2)	(28)
Deferred:			
Federal	(869)	76	(549)
State	(49)	1	(47)
	(918)	77	(596)
Total provision (benefit)	$(915)	$75	$(624)

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	$(893)	$71	$(604)
Increases (decreases) in taxes resulting from:			
State income taxes (net of federal benefit)	(35)	2	(31)
State income tax legislation change (net of federal benefit)	—	9	—
Effective state income tax rate change (net of federal benefit)	8	(9)	(3)
Other	5	2	14
Provision (benefit) for income taxes	$(915)	$75	$(624)

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

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 $9 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 $8 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

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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 be assumed by the purchaser (see Note 16 of Notes to Consolidated Financial Statements).

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

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, 5 and 16 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 $30 million, $27 million and $27 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.

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Notes to Consolidated Financial Statements—(Continued)

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 reflected in general and administrative expense for the years ended December 31, 2015, 2014 and 2013 was $35 million, $35 million and $31 million, respectively. 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

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

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

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(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.

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	December 31, 2015				December 31, 2014			
	Level 1	Level 2 (Millions)	Level 3	Total	Level 1	Level 2 (Millions)	Level 3	Total
Energy derivative assets	$—	$441	$—	$441	$14	$517	$5	$536
Energy derivative liabilities	$—	$15	$—	$15	$32	$10	$—	$42
Total debt(a)	$—	$2,495	$—	$2,495	$—	$2,218	$—	$2,218

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(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.

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

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

	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, 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. 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 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:

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

- $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.

(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. 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.

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

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	(412	)	$3.63	
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	Fixed Price Swaps	Henry Hub	(93	)	$3.22	
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.

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

Fair values and gains (losses)

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

	December 31, 2015		2014	
	Assets (Millions)	Liabilities	Assets	Liabilities
Derivatives related to production not designated as hedging instruments	$441	$15	$517	$10
Derivatives related to physical marketing agreements not designated as hedging instruments	—	—	19	32
Total derivatives not designated as hedging instruments	$441	$15	$536	$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.

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

Offsetting of derivative assets and liabilities

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

December 31, 2015	Gross Amount Presented on Balance Sheet (Millions)	Netting Adjustments (a)	Cash Collateral Posted(Received)	Net Amount
Derivative assets with right of offset or master netting agreements	$441	$(14)	$ —	$427
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	$536	$(25)	$ —	$511
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.

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

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	$168	$340
Joint interest owners	100	106
Other	44	13
Total	$312	$459

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 credit worthy 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)	$442	$428
Credit reserves	(1)	(1)
Credit exposure from derivatives	$441	$427

(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 credit worthy parties.

Revenues

During 2015, 2014 and 2013, BP Energy Company accounted for 9 percent, 13 percent and 16 percent of our consolidated revenues, respectively. During 2015, 2014 and 2013, Southern California Gas Company accounted for 7 percent, 8 percent and 11 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

On February 9, 2016 we signed an agreement to sell our Piceance Basin operations to Terra Energy Partners LLC (“Terra”), for $910 million. The agreement requires Terra to assume 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. The parties expect to close the sale in the second quarter of 2016.

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

WPX has a variety of options for the Piceance Basin proceeds, including debt reduction, additional drilling, infrastructure investments such as expanding its Permian Basin gathering system, and buying out of any retained transportation obligations.

The following unaudited pro forma condensed consolidated financial statements apply certain pro forma adjustments to the historical consolidated financial statements of WPX Energy, Inc. The pro forma adjustments give effect to the probable disposition of our operations in the Piceance Basin (“Disposition”). It is anticipated that these operations will qualify as discontinued operations and as a result would be reclassified from income (loss) from continuing operations to discontinued operations in accordance with the provisions of “Presentation of Financial Statements” in the Accounting Standards Codification in future filings.

The unaudited pro forma condensed consolidated statements of operations for the three years ended December 31, 2015 give effect to the reclassification of the results of the Piceance Basin from continuing operations. The unaudited pro forma condensed balance sheet as of December 31, 2015 assumes the transaction occurred on December 31, 2015. The unaudited pro forma condensed consolidated financial statements are presented for illustrative purposes only to reflect the Disposition and do not represent what our results of operations or financial position would actually have been had the Disposition occurred on the dates noted above, or project our results of operations or financial position for any future periods. The unaudited pro forma condensed consolidated financial statements are intended to provide information about the continuing impact of the Disposition as if it had been consummated earlier and do not represent any conclusions about whether such operations of the Piceance Basin will be reported as discontinued operations. The pro forma adjustments are based on available information and certain assumptions that management believes are factually supportable and are expected to have a continuing impact on our results of operations. In the opinion of management, all adjustments necessary to present fairly the unaudited pro forma condensed consolidated financial statements have been made.

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

	December 31, 2015		
	WPX Energy, Inc. - As Reported	Disposition(a)	Pro Forma
Assets	(Millions) (Unaudited)		
Current assets:			
Cash and cash equivalents	$38	$910	$948
Accounts receivable, net of allowance	312	(55)	257
Derivative assets	376	(68)	308
Inventories	59	(13)	46
Margin deposits	1	—	1
Assets classified as held for sale	40	—	40
Other	24	(2)	22
Total current assets	850	772	1,622
Properties and equipment, net (successful efforts method of accounting)	7,401	(879)	6,522
Derivative assets	65	(14)	51
Other noncurrent assets	34	—	34
Total assets	$8,350	$(121)	$8,229
Liabilities and Equity			
Current liabilities:			
Accounts payable	$328	$(93)	$235
Accrued and other current liabilities	349	(50)	299
Derivative liabilities	13	—	13
Total current liabilities	690	(143)	547
Deferred income taxes	465	—	465
Long-term debt, net	3,189	—	3,189
Derivative liabilities	2	—	2
Asset retirement obligations	232	(133)	99
Other noncurrent liabilities	237	—	237
Contingent liabilities and commitments (Note 10)			
Equity:			
Stockholders' equity:			
Preferred stock	339	—	339
Common stock	3	—	3
Additional paid-in-capital	6,164	—	6,164
Accumulated deficit	(2,971)	155	(2,816)
Accumulated other comprehensive income (loss)	—	—	—
Total stockholders' equity	3,535	155	3,690
Total liabilities and equity	$8,350	$(121)	$8,229

(a) Assumes receipt of $910 million of cash on December 31, 2015 for the assets and liabilities of Piceance Basin operations that are part of the probable Disposition. The $910 million purchase price does not assume any closing adjustments that will occur. The other amounts presented are the adjustments necessary to reflect the removal of the Piceance Basin assets and liabilities from our consolidated historical financial statements. These adjustments are based on available information and certain assumptions that management believes are factually supportable and may not represent the assets and liabilities that will be assumed by the buyer.

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

	Year Ended December 31, 2015		
	WPX Energy Inc. - As Reported	Disposition(b)	Pro Forma
Revenues:	(Millions, except per share amounts)		
Product revenues:	(Unaudited)		
Oil and condensate sales	$514	$ (20)	$494
Natural gas sales	563	(425)	138
Natural gas liquid sales	96	(73)	23
Total product revenues	1,173	(518)	655
Gas management	288	(2)	286
Net gain (loss) on derivatives not designated as hedges	418	—	418
Other	9	(2)	7
Total revenues	1,888	(522)	1,366
Costs and expenses:			
Lease and facility operating	220	(75)	145
Gathering, processing and transportation	282	(218)	64
Taxes other than income	75	(13)	62
Gas management, including charges for unutilized pipeline capacity	262	(1)	261
Exploration	111	(26)	85
Depreciation, depletion and amortization	940	(412)	528
Impairment of producing properties and costs of acquired unproved reserves	2,308	(2,308)	—
Net (gain) loss on sales of assets	(349)	—	(349)
General and administrative	249	(39)	210
Acquisition costs	23	—	23
Other—net	67	(4)	63
Total costs and expenses	4,188	(3,096)	1,092
Operating income (loss)	(2,300)	2,574	274
Interest expense	(187)	—	(187)
Loss on extinguishment of acquired debt	(65)	—	(65)
Investment income, impairment of equity method investment and other	(2)	—	(2)
Income (loss) from continuing operations before income taxes	(2,554)	2,574	20
Provision (benefit) for income taxes	(915)	949	34
Income (loss) from continuing operations	$(1,639)	$ 1,625	$(14)

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

	Year Ended December 31, 2014		
	WPX Energy Inc. - As Reported	Disposition(b)	Pro Forma
	(Millions, except per share amounts)		
	(Unaudited)		
Revenues:			
Product revenues:			
Oil and condensate sales	$724	$ (55)	$669
Natural gas sales	1,002	(720)	282
Natural gas liquid sales	205	(185)	20
Total product revenues	1,931	(960)	971
Gas management	1,120	(10)	1,110
Net gain (loss) on derivatives not designated as hedges	434	—	434
Other	8	—	8
Total revenues	3,493	(970)	2,523
Costs and expenses:			
Lease and facility operating	244	(101)	143
Gathering, processing and transportation	328	(257)	71
Taxes other than income	126	(38)	88
Gas management, including charges for unutilized pipeline capacity	987	(8)	979
Exploration	173	(72)	101
Depreciation, depletion and amortization	810	(447)	363
Impairment of producing properties and costs of acquired unproved reserves	20	(5)	15
Loss on sale of working interests in the Piceance Basin	196	(196)	—
General and administrative	271	(47)	224
Other—net	12	1	13
Total costs and expenses	3,167	(1,170)	1,997
Operating income (loss)	326	200	526
Interest expense	(123)	—	(123)
Investment income, impairment of equity method investment and other	1	—	1
Income (loss) from continuing operations before income taxes	204	200	404
Provision (benefit) for income taxes	75	73	148
Income (loss) from continuing operations	$129	$ 127	$256

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

	Year Ended December 31, 2013		
	WPX Energy Inc. - As Reported	Disposition(b)	Pro Forma
	(Millions, except per share amounts)		
	(Unaudited)		
Revenues:			
Product revenues:			
Oil and condensate sales	$534	$ (59)	$475
Natural gas sales	896	(637)	259
Natural gas liquid sales	228	(218)	10
Total product revenues	1,658	(914)	744
Gas management	891	(9)	882
Net gain (loss) on derivatives not designated as hedges	(124)	—	(124)
Other	6	(3)	3
Total revenues	2,431	(926)	1,505
Costs and expenses:			
Lease and facility operating	227	(118)	109
Gathering, processing and transportation	350	(277)	73
Taxes other than income	102	(34)	68
Gas management, including charges for unutilized pipeline capacity	931	(4)	927
Exploration	423	(6)	417
Depreciation, depletion and amortization	858	(504)	354
Impairment of producing properties and costs of acquired unproved reserves	860	(88)	772
General and administrative	269	(51)	218
Other—net	12	—	12
Total costs and expenses	4,032	(1,082)	2,950
Operating income (loss)	(1,601)	156	(1,445)
Interest expense	(108)	—	(108)
Investment income, impairment of equity method investment and other	(19)	—	(19)
Income (loss) from continuing operations before income taxes	(1,728)	156	(1,572)
Provision (benefit) for income taxes	(624)	57	(567)
Income (loss) from continuing operations	$(1,104)	$ 99	$(1,005)

(b) Amounts presented are the adjustments necessary to reflect the removal of the results of operations of the Piceance Basin from our consolidated historical financial statements. These adjustments are based on available information and certain assumptions that management believes are factually supportable and may not be indicative of future results of operations of the Piceance Basin assets.

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	$572	$284	$537	$495
Operating costs and expenses	$484	$431	$483	$492
Income (loss) from continuing operations	$22	$(23)	$(106)	$(1,532)
Income (loss) from discontinued operations	46	(7)	(124)	(2)
Net income (loss)	$68	$(30)	$(230)	$(1,534)
Amounts attributable to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	$22	$(23)	$(110)	$(1,537)
Income (loss) from discontinued operations	45	(7)	(124)	(2)
Net income (loss)	$67	$(30)	$(234)	$(1,539)
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$0.11	$(0.12)	$(0.44)	$(5.58)
Income (loss) from discontinued operations	0.22	(0.02)	(0.49)	(0.01)
Net income (loss)	$0.33	$(0.14)	$(0.93)	$(5.59)
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$0.11	$(0.12)	$(0.44)	$(5.58)
Income (loss) from discontinued operations	0.21	(0.02)	(0.49)	(0.01)
Net income (loss)	$0.32	$(0.14)	$(0.93)	$(5.59)
2014				
Revenues	$894	$727	$747	$1,125
Operating costs and expenses	$783	$659	$570	$656
Income (loss) from continuing operations	$—	$(144)	$46	$227
Income (loss) from discontinued operations	19	11	20	(8)
Net income (loss)	$19	$(133)	$66	$219
Amounts attributable to WPX Energy, Inc. common stockholders:				
Income (loss) from continuing operations	$—	$(144)	$46	$227
Income (loss) from discontinued operations	18	9	16	(8)
Net income (loss)	$18	$(135)	$62	$219
Basic earnings (loss) per common share:				
Income (loss) from continuing operations	$—	$(0.71)	$0.23	$1.11
Income (loss) from discontinued operations	0.09	0.05	0.07	(0.03)
Net income (loss)	$0.09	$(0.66)	$0.30	$1.08
Diluted earnings (loss) per common share:				
Income (loss) from continuing operations	$—	$(0.71)	$0.23	$1.10
Income (loss) from discontinued operations	0.09	0.05	0.07	(0.04)
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 producing properties and leasehold (see Note 5).
- $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.
- $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 Note 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.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures
(Unaudited)

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 through the completion of the sale of the Powder River Basin, which has been reported as discontinued operations in our consolidated financial statements. 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. Subsequent to December 31, 2015, we entered into an agreement for the sale of our Piceance Basin properties (see Note 16 of Notes to Consolidated Financial Statements). The Piceance Basin properties represent approximately 52 percent of our reserves.

Capitalized Costs

	As of December 31, 2015	2014
	(Millions)	
Proved Properties	$6,478	$10,717
Unproved properties	2,355	394
	8,833	11,111
Accumulated depreciation, depletion and amortization and valuation provisions	(1,763)	(4,698)
Net capitalized costs	$7,070	$6,413

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- Excluded from capitalized costs are equipment and facilities in support of oil and gas production of $292 million and $385 million, net, for 2015 and 2014, respectively. The $385 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

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- 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.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

- 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.

Results of Operations

	For the years ended December 31,		
	2015	2014	2013
	(Millions)		
Revenues:			
Oil and condensate sales	$ 514	$ 724	$ 534
Natural gas sales	563	1,002	896
Natural gas liquid sales	96	205	228
Net gain (loss) on derivatives not designated as hedges	438	515	(57)
Other revenues	9	8	6
Total revenues	1,620	2,454	1,607
Costs:			
Lease and facility operating	220	244	227
Gathering, processing and transportation	282	328	350
Taxes other than income	75	126	102
Exploration	111	173	423
Depreciation, depletion and amortization	940	810	858
Impairment of certain proved properties	2,308	15	772
Impairment of costs of acquired unproved reserves	—	5	88
Net (gain) loss on sales of assets	(349)	196	—
General and administrative	242	264	262
Acquisition costs	23	—	—
Other (income) expense	67	12	12
Total costs	3,919	2,173	3,094
Results of operations	(2,299)	281	(1,487)
Provision (benefit) for income taxes	(845)	103	(543)
Exploration and production net income (loss)	$ (1,454)	$ 178	$ (944)

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- 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 2015 include a $26 million impairment charge related to certain unproved leasehold in the Piceance Basin. 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.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

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.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

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.
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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 Note 4 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

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

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

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- 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.

WPX Energy, Inc.
Supplemental Oil and Gas Disclosures—(Continued)
(Unaudited)

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.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls and procedures (as defined in Rules 13a—15(e) and 15d—15(e) of the Securities Exchange Act) ("Disclosure Controls") will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. We monitor our Disclosure Controls and make modifications as necessary; our intent in this regard is that the Disclosure Controls will be modified as systems change and conditions warrant.

Evaluation of Disclosure Controls and Procedures

An evaluation of the effectiveness of the design and operation of our Disclosure Controls was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that these Disclosure Controls are effective at a reasonable assurance level.

Management's Annual Report on Internal Control over Financial Reporting

See report set forth in Item 8, "Financial Statements and Supplementary Data."

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

See report set forth in Item 8, "Financial Statements and Supplementary Data."

Fourth Quarter 2015 Changes in Internal Controls

There have been no changes during the fourth quarter of 2015 that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information called for by this Item 10 is incorporated by reference to our definitive proxy statement for our 2016 Annual meeting of Stockholders, or our 2016 Proxy Statement, anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, under the headings “Proposal 1— Election of Directors,” “Corporate Governance,” and “Section 16(a) Beneficial Ownership and Reporting Compliance.”

Item 11. Executive Compensation

The information called for by this Item 11 is incorporated by reference to our 2016 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, under the headings “Executive Compensation” and “Compensation Interlocks and Insider Participation.”

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by this Item 12 is incorporated by reference to our 2016 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, under the headings “Security Ownership of Certain Beneficial Owners and Management” and “Equity Compensation Plan Information.”

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information called for by this Item 13 is incorporated by reference to our 2016 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, under the headings “Corporate Governance” and “Certain Relationships and Transactions.”

Item 14. Principal Accountant Fees and Services

The information called for by this Item 14 is incorporated by reference to our 2016 Proxy Statement anticipated to be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, under the heading “Independent Registered Public Accounting Firm.”

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1 and 2.

(a) 3 and (b). The exhibits listed below are filed as part of this annual report.

INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Contribution Agreement, dated as of October 26, 2010, by and among Williams Production RMT Company, LLC, Williams Energy Services, LLC, Williams Partners GP LLC, Williams Partners L.P., Williams Partners Operating LLC and Williams Field Services Group, LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
2.2**	Agreement and Plan of Merger, dated October 2, 2014, by and among Pluspetrol Resources Corporation, Pluspetrol Black River Corporation and Apco Oil and Gas International Inc. (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on October 7, 2014)
2.3**	Agreement and Plan of Merger, dated as of July 13, 2015, by and among RKI Exploration & Production, LLC, WPX Energy, Inc. and Thunder Merger Sub LLC (incorporated herein by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 14, 2015)
2.4**	Membership Interest Purchase Agreement by and Among WPX Energy Holdings, LLC, as Seller, WPX Energy, Inc., solely for purposes of Section 14.15, and Terra Energy Partners LLC, as Purchaser, dated February 8, 2016 (incorporated by reference to Exhibit 2.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on February 9, 2016)
3.1	Restated Certificate of Incorporation of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
3.2	Amended and Restated Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on November 15, 2013)
3.3	Amended and Restated Bylaws of WPX Energy, Inc. (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on March 21, 2014)
3.4	Certificate of Designations for 6.25% Series A Mandatory Convertible Preferred Stock (incorporated herein by reference to Exhibit 3.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on July 22, 2015)
4.1	Indenture, dated as of November 14, 2011, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 15, 2011)
4.2	Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)

4.3	First Supplemental Indenture, dated as of September 8, 2014, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.2 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on September 8, 2014)
4.4	Second Supplemental Indenture, dated as of July 22, 2015, between WPX Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on July 22, 2015)
10.1	Separation and Distribution Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011)
10.2	Employee Matters Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.3	Tax Sharing Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)
10.4	Transition Services Agreement, dated as of December 30, 2011, between The Williams Companies, Inc. and WPX Energy, Inc. (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on January 6, 2012)

Exhibit No.	Description
10.5	Credit Agreement, dated as of June 3, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.3 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on June 9, 2011)
10.6 #	Amended and Restated Gas Gathering, Processing, Dehydrating and Treating Agreement by and among Williams Field Services Company, LLC, Williams Production RMT Company, LLC, Williams Production Ryan Gulch LLC and WPX Energy Marketing, LLC, effective as of August 1, 2011 (incorporated herein by reference to Exhibit 10.7 to WPX Energy, Inc.'s registration statement on Form S-1/A (File No. 333-173808) filed with the SEC on July 19, 2011)
10.7	Form of Change in Control Agreement between WPX Energy, Inc. and CEO (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012)(1)
10.8	Form of Change in Control Agreement between WPX Energy, Inc. and Tier One Executives (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.'s current report on Form 8-K (File No. 001-35322) filed with the SEC on July 23, 2012)(1)
10.9	First Amendment to the Credit Agreement, dated as of November 1, 2011, by and among WPX Energy, Inc., the lenders named therein, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.2 to The Williams Companies, Inc.'s Current report on Form 8-K (File No. 001-04174) filed with the SEC on November 1, 2011)
10.10	WPX Energy, Inc. 2013 Incentive Plan (incorporated herein by reference to Exhibit 4.1 to WPX Energy, Inc.'s Current report on Form 8-K (File No. 001-35322) filed with the SEC on May 29, 2013)(1)
10.11	WPX Energy, Inc. 2011 Employee Stock Purchase Plan (incorporated herein by reference to Exhibit 4.4 to WPX Energy, Inc.'s registration statement on Form S-8 (File No. 333-178388) filed with the SEC on December 8, 2011)(1)
10.12	Form of Restricted Stock Agreement between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011) (1)
10.13	Form of Restricted Stock Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.13 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.14	Form of Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.14 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2014) (1)
10.15	Form of Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.14 to WPX Energy, Inc.'s Quarterly

	Report on Form 10-Q for the quarter ended March 31, 2014)(1)
10.16	Form of Stock Option Agreement between WPX Energy, Inc. and Executive Officers (incorporated herein by reference to Exhibit 10.15 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012)(1)
10.17	WPX Energy Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.16 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012)(1)
10.18	WPX Energy Board of Directors Nonqualified Deferred Compensation Plan, effective January 1, 2013 (incorporated herein by reference to Exhibit 10.17 to WPX Energy, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012) (1)
10.19	Agreement, dated December 17, 2013, between WPX Energy, Inc. and Taconic Capital Advisors LP (incorporated herein by reference to Exhibit 99.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 18, 2013).
10.20	Retirement Agreement, dated December 16, 2013, between WPX Energy, Inc. and Ralph A. Hill (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current report on Form 8-K filed with the SEC on December 17, 2013).

Exhibit No.	Description
10.21	Severance Agreement, dated February 18, 2014, between WPX Energy, Inc. and Neal A. Buck (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.'s current report on Form 8-K filed with the SEC on February 19, 2014) (1)
10.22	Employment Agreement, dated April 29, 2014, between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.23	Form of Nonqualified Stock Option Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.24	Form of 2014 Time-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.3 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.25	Form of 2014 Performance-Based Restricted Stock Unit Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.4 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.26	Form of Time-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.5 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.27	Form of Performance-Based Restricted Stock Unit Inducement Award Agreement between WPX Energy, Inc. and Richard E. Muncrief (incorporated herein by reference to Exhibit 10.6 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on May 2, 2014) (1)
10.28	Form of Restricted Stock Unit Award between WPX Energy, Inc. and Non-Employee Directors (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.29	Separation and Release Agreement, dated July 28, 2014, between WPX Energy, Inc. and James J. Bender (incorporated herein by reference to Exhibit 10.2 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on September 3, 2014) (1)
10.30	WPX Energy Executive Severance Pay Plan (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on September 19, 2014) (1)
10.31	Amended and Restated Credit Agreement, dated as of October 28, 2014, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as Administrative Agent and Swingline Lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on November 3, 2014)
10.32	Form of Voting and Support Agreement, dated as of July 13, 2015, by and between WPX Energy, Inc. and the Member signatory thereto (incorporated herein by reference to Exhibit 10.1 to WPX Energy,

	Inc.’s Current Report on Form 8-K filed with the SEC on July 14, 2015)
10.33	First Amendment to the Amended and Restated Credit Agreement, dated as of July 16, 2015, by and among WPX Energy, Inc., the lenders party thereto, and Citibank, N.A., as existing administrative agent and existing swingline lender, and Wells Fargo Bank, National Association, as successor administrative agent and successor swingline lender (incorporated herein by reference to Exhibit 10.1 to WPX Energy, Inc.’s Current Report on Form 8-K filed with the SEC on July 22, 2015)
10.34	Commitment Increase Agreement for Amended and Restated Credit Agreement, dated as of July 31, 2015, among WPX Energy, Inc., the Lenders party thereto, Wells Fargo Bank, National Association, as Administrative Agent, and the Issuing Banks thereto (incorporated by reference to Exhibit 10.1 to WPX Energy, Inc.'s Current Report on Form 8-K filed with the SEC on August 6, 2015)
10.35	Registration Rights Agreement dated August 17, 2015, among WPX Energy, Inc. and the signatories thereto (incorporated herein by reference to Exhibit 10.35 to WPX Energy, Inc.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2015)
12*	Statement of Computation of Ratio of Earnings to Fixed Charges
21.1*	List of Subsidiaries

Exhibit No.	Description
23.1*	Consent of Independent Registered Public Accounting Firm, Ernst & Young LLP
23.2*	Consent of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
24.1*	Powers of Attorney
31.1*	Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1*	Certification by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99.1*	Report of Independent Petroleum Engineers and Geologists, Netherland, Sewell & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

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

* Filed herewith

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

(1) Management contract or compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: February 25, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Richard E. Muncrief	President, Chief Executive Officer and Director (Principal Executive Officer)	February 25, 2016
/s/ J. Kevin Vann	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 25, 2016
/s/ Stephen L. Faulkner	Controller (Principal Accounting Officer)	February 25, 2016
/s/ John A. Carrig*	Director	February 25, 2016
/s/ William R. Granberry*	Director	February 25, 2016
/s/ Robert K. Herdman*	Director	February 25, 2016
/s/ Kelt Kindick*	Director	February 25, 2016
/s/ Karl F. Kurz*	Director	February 25, 2016
/s/ Henry E. Lentz*	Director	February 25, 2016
/s/ George A. Lorch*	Director	February 25, 2016
/s/ William G. Lowrie*	Chairman of the Board	February 25, 2016
/s/ Kimberly S. Lubel*	Director	February 25, 2016
/s/ David F. Work*	Director	February 25, 2016

	/s/ Stephen E. Brilz	
*By:	Attorney-in-Fact	February 25, 2016

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