EP Energy Corp
Form 10-K
February 22, 2016
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K
(Mark One)
x 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
o 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 001-36253

EP Energy Corporation
(Exact Name of Registrant as Specified in Its Charter)

Delaware	46-3472728
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1001 Louisiana Street Houston, Texas	77002
(Address of Principal Executive Offices)	(Zip Code)

Telephone Number: (713) 997-1200
Internet Website: www.epenergy.com
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Class A Common Stock, par value $0.01 per share	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 o No x.
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 o No x.
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 x No o.
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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o.
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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. x

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 o	Accelerated filer x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

Aggregate market value of the Company’s common stock held by non-affiliates of the registrant as of June 30, 2015, was $450,746,921 based on the closing sale price on the New York Stock Exchange.

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date.

Class A Common Stock, par value $0.01 per share. Shares outstanding as of February 10, 2016: 247,961,372

Class B Common Stock, par value $0.01 per share. Shares outstanding as of February 10, 2016: 793,508

Documents Incorporated by Reference: Portions of the definitive proxy statement for the 2016 Annual Meeting of Stockholders of EP Energy Corporation, which will be held on May 11, 2016, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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PART IV

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Below is a list of terms that are common to our industry and used throughout this document:

/d	=	per day
Bbl	=	barrel
Bcf	=	billion cubic feet
Boe	=	barrel of oil equivalent
CBM	=	coal bed methane
Gal	=	gallons
LLS	=	light Louisiana Sweet crude oil
LNG	=	liquefied natural gas
MBoe	=	thousand barrels of oil equivalent
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
MMGal	=	million gallons
MMBtu	=	million British thermal units
MMBoe	=	million barrels of oil equivalent
MMBbls	=	million barrels
MMcf	=	million cubic feet
MMcfe	=	million cubic feet of natural gas equivalents
NGLs	=	natural gas liquids
TBtu	=	trillion British thermal units
WTI	=	West Texas intermediate

When we refer to oil and natural gas in “equivalents,” we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil and/or NGLs is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to “us”, “we”, “our”, “ours”, “the Company”, or “EP Energy”, we are describing EP Energy Corporation and/or subsidiaries.

All references to “common stock” herein refer to Class A common stock.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that involve risks and uncertainties, many of which are beyond our control. These forward-looking statements are based on assumptions or beliefs that we believe to be reasonable; however, assumed facts almost always vary from the actual results and such variances can be material. Where we express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the stated expectation or belief will occur. The words "believe", "expect", "estimate", "anticipate", "intend" and "should" and similar expressions will generally identify forward-loo statements. All of our forward-looking statements are expressly qualified by these and the other cautionary statements in this Annual Report, including those set forth in Item 1A, Risk Factors. Important factors that could cause our actual results to differ materially from the expectations reflected in our forward-looking statements include, among others:

- the volatility of and current sustained low oil, natural gas, and NGLs prices;
- the supply and demand for oil, natural gas and NGLs;
- changes in commodity prices and basis differentials for oil and natural gas;
- our ability to meet production volume targets;
- the uncertainty of estimating proved reserves and unproved resources;
- the future level of service and capital costs;
- the availability and cost of financing to fund future exploration and production operations;
- the success of drilling programs with regard to proved undeveloped reserves and unproved resources;
- our ability to comply with the covenants in various financing documents;
- our ability to obtain necessary governmental approvals for proposed exploration and production projects and to successfully construct and operate such projects;
- actions by credit rating agencies;
- credit and performance risks of our lenders, trading counterparties, customers, vendors, suppliers and third party operators;
- general economic and weather conditions in geographic regions or markets we serve, or where operations are located, including the risk of a global recession and negative impact on demand for oil and/or natural gas;
- the uncertainties associated with governmental regulation, including any potential changes in federal and state tax laws and regulations;
- competition; and
- the other factors described under Item 1A, "Risk Factors," on pages 16 through 34 of this Annual Report on Form 10-K, and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

In light of these risks, uncertainties and assumptions, the events anticipated by these forward-looking statements may not occur, and, if any of such events do occur, we may not have anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of these forward-looking statements. These forward-looking statements speak only as of the date made, and we undertake no obligation, other than as required by applicable law, to update or revise its forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

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PART I

ITEM 1. BUSINESS

Overview

EP Energy Corporation (EP Energy), a Delaware Corporation formed in 2013, is an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. On May 24, 2012, affiliates of Apollo Global Management LLC (together with its subsidiaries, Apollo), Riverstone Holdings LLC (Riverstone), Access Industries (Access) and Korea National Oil Corporation (KNOC) (collectively, the Sponsors) and other co-investors acquired the predecessor entity to EP Energy for approximately $7.2 billion in cash as contemplated by a merger agreement among El Paso Corporation (El Paso) and Kinder Morgan, Inc. (KMI).

We operate through a large and diverse base of producing assets and are focused on creating value through the development of our low-risk drilling inventory located predominantly in four areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), the Altamont Field in the Uinta Basin (Northeastern Utah) and the Haynesville Shale (North Louisiana). In our four areas, we have identified 5,709 drilling locations (including 865 drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2015, of which 100% are oil wells). At 2015 activity levels, this represents approximately 30 years of drilling inventory. As of December 31, 2015, we had proved reserves of 546.0 MMBoe (55% oil and 71% liquids) and for the year ended December 31, 2015, we had average net daily production of 109,681 Boe/d (55% oil and 69% liquids).

Each of our areas is characterized by a long-lived reserve base and high drilling success rates. We have established significant contiguous leasehold positions in each area, representing approximately 487,000 net (660,000 gross) acres in total. Our capital programs have predominantly focused on the Eagle Ford Shale, the Wolfcamp Shale and Altamont, three of the premier unconventional oil plays in the United States, resulting in oil production growth of 10% from December 31, 2014 to December 31, 2015.

We evaluate growth opportunities in our portfolio that are aligned with our core competencies and that are in areas that we believe can provide us a competitive advantage. Strategic acquisitions of leasehold acreage or acquisitions of producing assets can provide opportunities to achieve our long-term goals by leveraging existing expertise in each of our four areas, balancing our exposure to regions, basins and commodities, helping us to achieve risk-adjusted returns competitive with those available within our existing drilling program and by increasing our reserves. We continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term goals and objectives.

Pursuant to our strategy, beginning in 2013, we divested of certain non-core domestic natural gas and other assets in order to principally focus on onshore, oil-weighted assets. In 2014, we acquired producing properties and undeveloped acreage in the Southern Midland Basin, of which 37,000 net acres are adjacent to our existing Wolfcamp Shale position. The acquisition represented an approximate 25% expansion of our Wolfcamp acreage. Additionally, we completed the sale of (i) non-core assets in our Arklatex area and South Louisiana Wilcox area (approximately 78,000 net acres, excluding Haynesville and Bossier rights), (ii) our Brazilian operations and (iii) certain non-core acreage in Atascosa County in the Eagle Ford Shale. In 2015, we acquired approximately 12,000 net acres adjacent to our Eagle Ford Shale acreage adding an average of 483 Bbls/d of oil and 660 Boe/d to our annual 2015 production. As of December 31, 2015, we estimate this acquisition added 197 drilling locations.

The following table provides a summary of oil, natural gas and NGLs reserves as of December 31, 2015 and production data for the year ended December 31, 2015 for each of our areas of operation.

	Estimated Proved Reserves[1]						
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Liquids (%)	Proved Developed (%)	Average Net Daily Production (MBoe/d)
Eagle Ford Shale	156.0	52.0	313.4	260.2	80 %	42 %	58.2
Wolfcamp Shale	63.8	38.9	249.6	144.3	71 %	39 %	19.9
Altamont	78.9	—	170.2	107.3	74 %	54 %	17.1

Haynesville Shale	—	—	205.0	34.2	—	%	100	%	14.4
Other[(2)]	—	—	0.2	—	—	%	100	%	0.1
Total[(3)]	298.7	90.9	938.4	546.0	71	%	47	%	109.7

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $50.28 per Bbl (WTI) and $2.59 per MMBtu (Henry Hub). The spot prices at December 31, 2015, were $37.04 per Bbl and $2.34 per MMBtu.

(2) Estimated proved reserves are comprised of outside operated overriding interests in the Gulf of Mexico and Rockies. Average net daily production is comprised of outside operated overriding interests in the Gulf of Mexico, Rockies and East Texas/North Louisiana.

(3) Includes 15 MMBoe of proved developed non-producing reserves representing 3% of total net proved reserves at December 31, 2015.

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Approximately 242 MMBoe, or 44%, of our total proved reserves are proved developed producing assets, which generated an average production of 109.7 MBoe/d in 2015 from approximately 1,605 wells. As of December 31, 2015, we had approximately 299 MMBbls of proved oil reserves, 91 MMBbls of proved NGLs reserves and 938 Bcf of proved natural gas reserves, representing 55%, 16% and 29%, respectively, of our total proved reserves. For the year ended December 31, 2015, 69% of our production was related to oil and NGLs versus 68% in 2014 and over that same period and on that same basis, our oil production grew by approximately 10%.

We operate 86% of our producing wells and have operational control over approximately 97% of our drilling inventory as of December 31, 2015. This control provides us with flexibility around the amount and timing of capital spending and has allowed us to continually improve our capital and operating efficiencies. In 2015, we realized 20% in capital cost and 13% in operating cost savings across our programs. We also employ a centralized drilling and completion structure to accelerate our internal knowledge transfer around the execution of our drilling and completion programs. In 2015, we drilled 188 wells with a success rate of 100%, adding approximately 69 MMBoe of proved reserves (76% of which were liquids). As of December 31, 2015, we also had a total of 77 wells drilled, but not completed across our programs.

Our Properties

Eagle Ford Shale. The Eagle Ford Shale, located in South Texas, is one of the premier unconventional oil plays in the United States. We were an early entrant into this play in late 2008, and since that time have acquired a leasehold position in the core of the oil window, primarily in La Salle County. The Eagle Ford formation in La Salle County has up to 125 feet of net thickness (165 feet gross). Due to its high carbonate content, the formation is also very brittle, and exhibits high productivity when fractured. In 2015, we acquired approximately 12,000 net acres adjacent to our Eagle Ford Shale. As of December 31, 2015, we had 94,153 net (106,054 gross) acres in the Eagle Ford, and we have identified 973 drilling locations.

During 2015, we invested $855 million in capital (including approximately $112 million in acquisition capital) in our Eagle Ford Shale and operated an average of 3.7 drilling rigs. As of December 31, 2015, we had 571 net producing wells (563 net operated wells) and are currently running one rig in this program. For the year ended December 31, 2015, our average net daily production was 58,187 Boe/d, representing growth of 14% over the same period in 2014. For the year ended December 31, 2015 our average cost per gross well was $5.8 million ($5.5 million per net well), representing a 19% decline from both our average cost per gross and net well compared to the year ended December 31, 2014.

Wolfcamp Shale. The Wolfcamp Shale is located in the Permian Basin. The Permian Basin is characterized by numerous, stacked oil reservoirs that provide excellent targets for horizontal drilling. In 2009 and 2010, we leased 138,130 net (138,469 gross) acres on the University of Texas Land System in the Wolfcamp Shale, located primarily in Reagan, Crockett, Upton and Irion counties.

Our large, contiguous acreage positions are characterized by stacked pay zones, including the Wolfcamp A, B, and C zones, which combine for over 750 feet of net (approximately 1,000 feet of gross) thickness. The Wolfcamp has high organic content and is composed of interbedded shale, silt, and fine-grained carbonate that respond favorably to fracture stimulation. As of December 31, 2015, we have 178,111 net (178,281 gross) acres in the Wolfcamp, in which we have identified approximately 3,264 drilling locations in the Wolfcamp A, B, and C zones.

The acreage is also prospective for the Cline Shale, which has approximately 100 feet of net (approximately 200 feet of gross) thickness, and potential vertical drilling locations in the Spraberry and other stacked formations.

During 2015, we invested $249 million in capital in our Wolfcamp Shale and operated an average of 1.2 drilling rigs. As of December 31, 2015, we had 240 net producing wells (237 net operated wells). We are not currently running a rig in this program. For the year ended December 31, 2015, our average net daily production was 19,846 Boe/d, representing growth of 30% over 2014. For the year ended December 31, 2015, our average cost per gross and net well was $5.3 million, representing a 15% decline from our average cost per gross and net well compared to the year ended December 31, 2014.

Altamont. The Altamont field is located in the Uinta Basin in northeastern Utah. The Uinta Basin is characterized by naturally fractured, tight-oil sands and carbonates with multiple pay zones. Our operations are primarily focused on developing the Altamont Field Complex (comprised of the Altamont, Bluebell and Cedar Rim fields), which is the largest field in the basin. We own 180,944 net (323,214 gross) acres in Duchesne and Uinta Counties. The Altamont Field Complex has a gross pay interval thickness of over 4,300 feet and we believe the Wasatch and Green River formations are ideal targets for low-risk, infill, vertical drilling and modern fracture stimulation techniques. Our commingled production is from over 1,500 feet of net stimulated rock. Our current activity is mainly focused on the development of our vertical inventory on 80-acre and 160-acre spacing. As of December 31, 2015, we have identified 1,282 drilling locations. Industry activity has also focused on horizontal drilling in the Wasatch and Green River formations testing tight carbonate and sand intervals and has also piloted 80-acre vertical downspacing in these formations. Due to the largely held-by-production nature of our acreage position, if these

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programs are successful, they will result in additional vertical and horizontal drilling opportunities that could be added to our inventory of drilling locations.

During 2015, we invested $158 million in capital in the Altamont Field, operated an average of 1.5 drilling rigs, and drilled 30 operated gross wells. As of December 31, 2015, we had 387 net producing wells (378 net operated wells). We are not currently running a rig in this program. For the year ended December 31, 2015, our average net daily production was 17,142 Boe/d, representing growth of 11% over 2014. For the year ended December 31, 2015 our average cost per gross well was $4.1 million ($3.6 million per net well), representing a 21% decline from our average cost per gross well (18% per net well) compared to the year ended December 31, 2014.

In February 2016, we entered into a drilling partnership with a third party under which we will jointly develop 12 wells in Altamont. We will operate the wells and the transaction is expected to increase well-level returns on the jointly developed wells. We will begin drilling partnership wells in the first half of 2016.

Haynesville Shale. In addition to our oil programs, we hold significant natural gas assets in the Haynesville Shale, located in East Texas and Northern Louisiana. Our operations are concentrated primarily in Desoto Parish, Louisiana in the Holly Field. We currently have 34,167 net (52,933 gross) acres in this area. As of December 31, 2015, we have identified 190 drilling locations.

During 2015, we invested $60 million in capital in our Haynesville Shale program. For the year ended December 31, 2015, our average net daily production was 87 MMcf/d. As of December 31, 2015, we had 110 net producing wells. Our acreage in the Haynesville Shale is held-by-production.

The following table provides a summary of acreage and inventory data as of December 31, 2015:

	Acres						
	Gross	Net	Drilling Locations[1] (#)	2015 Drilling Locations[2] (#)	Inventory (Years)[3]	Working Interest (%)	Net Revenue Interest (%)
Eagle Ford Shale	106,054	94,153	973	118	8.2	83 %	62 %
Wolfcamp Shale	178,281	178,111	3,264	36	90.7	97 %	72 %
Wolfcamp A			1,161			96 %	72 %
Wolfcamp B			1,006			96 %	72 %
Wolfcamp C			1,097			97 %	73 %
Altamont	323,214	180,944	1,282	30	42.7	73 %	62 %
Haynesville Shale	52,933	34,167	190	4	47.6	76 %	61 %
Holly			142			74 %	59 %
Non-Holly			48			86 %	68 %
Total	660,482	487,375	5,709	188	30.4	88 %	68 %

(1) Our inventory as of December 31, 2015 does not include the following potential additional locations:

- In the Wolfcamp Shale area, (i) horizontal drilling locations in the Cline Shale and (ii) vertical drilling locations in the Spraberry and other stacked formations; and
- In Altamont, (i) additional vertical infill locations and (ii) horizontal drilling locations in the Wasatch and Green River formations.

(2) Represents gross operated wells completed in 2015.

(3) Calculated as Drilling Locations divided by 2015 Drilling Locations.

We have used the data from our development programs to identify and prioritize our inventory. These drilling locations are only included in our inventory after they have been evaluated technically.

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Oil and Natural Gas Properties

Oil, Natural Gas and NGLs Reserves and Production

Proved Reserves

The table below presents information about our estimated proved reserves as of December 31, 2015, based on our internal reserve report. The reserve data represents only estimates which are often different from the quantities of oil and natural gas that are ultimately recovered. The risks and uncertainties associated with estimating proved oil and natural gas reserves are discussed further in Item 1A, “Risk Factors”. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2015.

	Net Proved Reserves[1]					
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Percent (%)	
Reserves by Classification						
Proved Developed						
Eagle Ford Shale	68.9	19.9	120.3	108.9	20	%
Wolfcamp Shale	21.8	16.6	106.6	56.1	10	%
Altamont	41.1	—	97.8	57.4	11	%
Haynesville Shale	—	—	205.0	34.2	6	%
Other[2]	—	—	0.2	—	—	%
Total Proved Developed[3]	131.8	36.5	529.9	256.6	47	%
Proved Undeveloped						
Eagle Ford Shale	87.1	32.1	193.0	151.3	28	%
Wolfcamp Shale	42.0	22.3	143.1	88.2	16	%
Altamont	37.8	—	72.4	49.9	9	%
Haynesville Shale	—	—	—	—	—	%
Other[2]	—	—	—	—	—	%
Total Proved Undeveloped	166.9	54.4	408.5	289.4	53	%
Total Proved Reserves	298.7	90.9	938.4	546.0	100	%

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $50.28 per Bbl (WTI) and $2.59 per MMBtu (Henry Hub).

(2) Comprised of outside operated overriding interests in the Gulf of Mexico and Rockies.

(3) Includes 242 MMBoe of proved developed producing reserves representing 44% of total net proved reserves and 15 MMBoe of proved developed non-producing reserves representing 3% of total net proved reserves at December 31, 2015.

Our reserves in the table above are consistent with estimates of reserves filed with other federal agencies except for differences of less than 5% resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience. Our estimated net proved reserves were prepared by our internal reserve engineers and audited by Ryder Scott Company, L.P. (Ryder Scott), our independent petroleum engineering consultants.

The table below presents net proved reserves as reported and sensitivities related to our estimated proved reserves based on differing price scenarios as of December 31, 2015.

	Net Proved Reserves (MMBoe)
As Reported	546.0
10 percent increase in commodity prices	553.6
10 percent decrease in commodity prices	393.5

The sensitivities in the table above were based on the average first day of the month spot price for the preceding 12-month period of $50.28 per barrel of oil (WTI) and $2.59 per MMBtu of natural gas (Henry Hub) used to determine net proved reserves at December 31, 2015.

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We employ a technical staff of engineers and geoscientists that perform technical analysis of each undeveloped location. The staff uses industry accepted practices to estimate, with reasonable certainty, the economically producible oil and natural gas. The practices for estimating hydrocarbons in place include, but are not limited to, mapping, seismic interpretation of two-dimensional and/or three-dimensional data, core analysis, mechanical properties of formations, thermal maturity, well logs of existing penetrations, correlation of known penetrations, decline curve analysis of producing locations with significant production history, well testing, static bottom hole testing, flowing bottom hole pressure analysis and pressure and rate transient analysis.

Our primary internal technical person in charge of overseeing our reserves estimates has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is the executive vice president and chief operating officer of the company. In this capacity, he is responsible for the Company's operating divisions, drilling and completions, and our Marketing group. He also oversees the reserve reporting and technical support groups. He has more than 27 years of industry experience in various domestic and international engineering and management roles. For a discussion of the internal controls over our proved reserves estimation process, see Part II, Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Critical Accounting Estimates".

Ryder Scott conducted an audit of the estimates of net proved reserves that we prepared as of December 31, 2015. In connection with its audit, Ryder Scott reviewed 99% (by volume) of our total net proved reserves on a barrel of oil equivalent basis, representing 98% of the total discounted future net cash flows of these net proved reserves. For the audited properties, 100% of our total net proved undeveloped (PUD) reserves were evaluated. Ryder Scott concluded that the overall procedures and methodologies that we utilized in preparing our estimates of net proved reserves as of December 31, 2015 complied with current SEC regulations and the overall net proved reserves for the reviewed properties as estimated by us are, in aggregate, reasonable within the established audit tolerance guidelines of 10% as set forth in the Society of Petroleum Engineers auditing standards. Ryder Scott's report is included as an exhibit to this Annual Report on Form 10-K.

The technical person primarily responsible for overseeing the reserves audit by Ryder Scott has a B.S. degree in chemical engineering. He is a Licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has more than 12 years of experience in petroleum reserves evaluation.

In general, the volume of production from oil and natural gas properties declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties with proved reserves, or both, our proved reserves will decline as they are produced. Recovery of PUD reserves requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes, may cause these assumptions to change. In addition, estimates of PUD reserves and proved non-producing reserves are inherently subject to greater uncertainties than estimates of proved producing reserves. For further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, under the heading Supplemental Oil and Natural Gas Operations.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2015, we have 289 MMBoe of PUD reserves and 865 PUD locations within our areas, all of which are scheduled to be developed or drilled within five years of their initial recording. Estimated capital expenditures to develop our PUD reserves (convert PUD reserves to proved developed reserves) are based upon a long-range plan approved by the Board of Directors. All PUD locations are surrounded by producing properties, and a majority of our PUDs directly offset a producing property. Where we have recorded PUDs beyond one location away from a producing property, reasonable certainty of economic producibility has been established by reliable technology in our areas, including field tests that demonstrate consistent and repeatable results within the formation being evaluated.

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We assess our PUD reserves on a quarterly basis. The following table summarizes our changes in PUDs for the years ended December 31, 2014 and December 31, 2015, respectively (in MMBoe):

Balance, December 31, 2013	365
Purchase of minerals in place	3
Extensions and discoveries[1]	75
Revisions due to prices	34
Revisions other than prices[2]	(10)
Transfers to proved developed	(75)
Divestitures	(8)
Balance, December 31, 2014	384
Purchase of minerals in place	6
Extensions and discoveries	58
Revisions due to prices	(3)
Revisions other than prices	(101)
Transfers to proved developed	(55)
Balance, December 31, 2015	289

(1) Includes 2 MMBoe related to South Louisiana Wilcox assets sold in 2014.

Purchases of minerals in place related to PUD reserves in our Wolfcamp, Eagle Ford and Altamont areas in 2014 and 2015. Extensions and discoveries in 2014 and 2015 are primarily related to drilling activities in the Eagle Ford, Wolfcamp and Altamont areas. Revisions due to prices represent PUD revisions due to increases or decreases in commodity prices (using SEC average pricing). Revisions other than prices represent PUD revisions for changing well performance, or revisions due to the impact of the SEC's five-year development rule after reductions in the estimated capital in our long-range plan based on the lower price environment. The year ended December 31, 2015, includes negative PUD revisions of 85 MMBoe, the majority of which relate to the removal of all of our PUDs in our Haynesville area. The year ended December 31, 2014, includes negative PUD revisions of 2 MMBoe due to long-range development plan reductions resulting from changes in economic outlook.

As of December 31, 2015, 145 MMBoe of our PUDs had a positive undiscounted value, but a negative value when discounted at 10 percent. A majority of these discounted negative value PUD reserves are associated with a long-term drilling commitment. During 2015, 2014 and 2013, we spent approximately $835 million, $1,192 million and $679 million, respectively, to convert approximately 14% or 55 MMBoe, 20% or 75 MMBoe and 12% or 39 MMBoe, respectively, of our prior year-end PUD reserves to proved developed reserves. In 2016, 2017 and 2018 we estimate we will spend approximately $746 million, $763 million and $963 million to develop our PUD reserves, respectively, based on our December 31, 2015 internal reserve report. The actual amount and timing of our forecasted expenditures will depend on a number of factors, including actual drilling results, service costs and future commodity prices which are currently and could in the future be lower than those in our projected long-range plan.

As of December 31, 2015, the average first day of the month spot price for the preceding 12-month period used for recording our PUDs was $50.28 per barrel of oil. Assuming the 12-month average price per barrel of oil had been $40.00, 125 MMBoe of our PUDs would have remained economic on an undiscounted basis, whereas at a 12-month average price of $30.00 per barrel of oil, none of our PUDs would be economic to develop. The reduction in our PUDs at these oil prices does not assume any associated cost reductions that may be achieved which could mitigate these assumed reductions in our PUDs.

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Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2015, (ii) our interest in oil and natural gas wells at December 31, 2015 and (iii) our exploratory and development wells drilled during the years 2013 through 2015. Any acreage in which our interest is limited to owned royalty, overriding royalty and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
Acreage						
Eagle Ford Shale	38,065	34,101	67,989	60,052	106,054	94,153
Wolfcamp Shale	16,762	16,598	161,519	161,513	178,281	178,111
Altamont	87,603	65,126	235,611	115,818	323,214	180,944
Haynesville Shale	16,950	11,283	35,983	22,884	52,933	34,167
Other	102,949	8,036	278,715	155,380	381,664	163,416
Total Acreage	262,329	135,144	779,817	515,647	1,042,146	650,791

(1) Gross interest reflects the total acreage we participate in regardless of our ownership interest in the acreage.
(2) Net interest is the aggregate of the fractional working interests that we have in the gross acreage.

Our net developed acreage is concentrated in Utah (48%), Texas (41%) and Louisiana (8%). Our net undeveloped acreage is concentrated in Texas (44%), Utah (20%), Michigan (10%), Wyoming (9%), West Virginia (8%), Louisiana (6%) and Colorado (3%). Approximately 10%, 2% and 2% of our net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2016, 2017 and 2018, respectively. We employ various techniques to manage the expiration of leases, including drilling the acreage ourselves prior to lease expiration, entering into farm-out or joint development agreements with other operators or extending lease terms.

	Oil		Natural Gas		Total		Wells Being Drilled at December 31, 2015(1)	
	Gross(2)	Net(3)	Gross(2)	Net(3)	Gross(2)	Net(3)(4)	Gross(2)	Net(3)
Productive Wells								
Eagle Ford Shale	637	568	3	3	640	571	49	48
Wolfcamp Shale	243	240	—	—	243	240	36	36
Altamont	500	386	3	1	503	387	8	7
Haynesville Shale	—	—	219	110	219	110	—	—
Total Productive Wells	1,380	1,194	225	114	1,605	1,308	93	91

(1) Comprised of wells that were spud as of December 31, 2015 and have not been completed.
(2) Gross interest reflects the total wells we participated in, regardless of our ownership interest.
(3) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.
(4) At December 31, 2015, we operated 1,281 of the 1,308 net productive wells.

	Net Exploratory(1)			Net Development(1)		
	2015	2014	2013	2015	2014	2013
Wells Drilled						
Productive	—	5	8	180	257	216
Dry	—	—	—	—	—	2
Total Wells Drilled	—	5	8	180	257	218

(1) Net interest is the aggregate of the fractional working interests that we have in the gross wells or gross wells drilled.

The drilling performance above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered.

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Net Production, Sales Prices, Transportation and Production Costs

The following table details our net production volumes, net production volume by area, average sales prices received, average transportation costs, average lease operating expense and average production taxes associated with the sale of oil, natural gas and NGLs for each of the three years ended December 31:

	2015	2014	2013
Volumes:			
Net Production Volumes			
Oil (MBbls)	22,078	19,985	13,235
Natural Gas (MMcf)	75,533	69,434	83,816
NGLs (MBbls)	5,366	4,116	2,434
Total (MBoe)	40,033	35,673	29,638
Divested Assets(1)			
Oil (MBbls)	—	—	197
Natural Gas (MMcf)	—	—	10,050
NGLs (MBbls)	—	—	327
Total (MBoe)	—	—	2,199
Total Net Production Volumes			
Oil (MBbls)	22,078	19,985	13,432
Natural Gas (MMcf)	75,533	69,434	93,866
NGLs (MBbls)	5,366	4,116	2,761
Total Equivalent Volumes (MBoe)	40,033	35,673	31,837
MBoe/d(2)	109.7	97.7	87.2

(1) Volumes in 2013 represent volumes from our approximate 49% equity interest in the volumes of Four Star Oil & Gas Company (Four Star), which we sold in September 2013.

(2) The year ended December 31, 2013 includes 6.0 MBoe/d from Four Star.

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	2015	2014	2013
Net Production Volumes by Area			
Eagle Ford Shale			
Oil (MBbls)	14,220	12,698	8,763
Natural Gas (MMcf)	21,212	18,215	14,857
NGLs (MBbls)	3,483	2,851	2,133
Total Eagle Ford Shale (MBoe)	21,238	18,585	13,372
Wolfcamp Shale			
Oil (MBbls)	3,321	3,073	1,306
Natural Gas (MMcf)	12,317	7,551	2,483
NGLs (MBbls)	1,870	1,237	280
Total Wolfcamp Shale (MBoe)	7,244	5,568	2,000
Altamont			
Oil (MBbls)	4,532	4,208	3,161
Natural Gas (MMcf)	10,299	8,504	6,931
NGLs (MBbls)	9	21	11
Total Altamont (MBoe)	6,257	5,646	4,327
Haynesville Shale			
Oil (MBbls)	—	—	—
Natural Gas (MMcf)	31,521	34,907	59,335
NGLs (MBbls)	—	—	—
Total Haynesville Shale (MBoe)	5,253	5,818	9,889

	2015	2014	2013
Prices and Costs per Unit:(1)(2)			
Oil Average Realized Sales Price ($/Bbl)			
Physical Sales	$44.28	$85.31	$94.75
Including Financial Derivatives(3)	$82.18	$88.77	$97.56
Natural Gas Average Realized Sales Price ($/Mcf)			
Physical Sales	$2.27	$3.76	$3.28
Including Financial Derivatives(3)	$3.59	$3.34	$2.97
NGLs Average Realized Sales Price ($/Bbl)			
Physical Sales	$11.22	$26.73	$30.58
Including Financial Derivatives(3)	$12.36	$27.78	$—
Average Transportation Costs			
Oil ($/Bbl)	$1.55	$1.65	$2.01
Natural Gas ($/Mcf)	$0.91	$0.65	$0.52
NGLs ($/Bbl)	$2.31	$5.42	$6.07
Average Lease Operating Expenses ($/Boe)	$4.64	$5.40	$4.98
Average Production Taxes ($/Boe)	$1.83	$3.39	$2.84

(1) Prices and costs per unit are calculated excluding volumes related to Four Star which was sold in September 2013.

(2) Oil prices for the year ended December 31, 2015 are calculated including a reduction of $3 million for oil purchases associated with managing our physical sales. Natural gas prices for the years ended December 31, 2015, 2014 and 2013 are calculated including a reduction of $28 million, $23 million and $25 million, respectively, for natural gas purchases associated with managing our physical sales.

(3) Amounts reflect settlements on financial derivatives, including cash premiums. No cash premiums were received or paid for the year ended December 31, 2015. For the years ended December 31, 2014 and 2013, we received

approximately $1 million and $9 million of cash premiums, respectively.

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Acquisition, Development and Exploration Expenditures

See Part II, Item 8, Financial Statements and Supplementary Data under the heading Supplemental Oil and Natural Gas Operations in the Total Costs Incurred table for details on our acquisition, development and exploration expenditures.

Transportation, Markets and Customers

Our marketing strategy seeks to ensure both maximum deliverability of our physical production and maximum realized prices. We leverage our knowledge of markets and transportation infrastructure to enter into favorable downstream processing, treating and marketing contracts. We primarily sell our domestic oil and natural gas production to third parties at spot market prices, while we sell our NGLs at market prices under monthly or long-term contracts. We typically sell our oil production to a relatively small number of creditworthy counterparties, as is customary in the industry. For the year ended December 31, 2015, five purchasers accounted for approximately 74% of our oil revenues: Plains Marketing LP, Flint Hills Resources, LP (an affiliate of Koch Industries), Enterprise Crude Oil LLC, Shell Trading U.S. Co. (an affiliate of Shell Oil Company), and Big West Oil LLC. We anticipate further diversification of our revenue exposure to a wider range of buyers under a mix of short-term and long-term sales agreements. Across all of our areas, we maintain adequate gathering, treating, processing and transportation capacity, as well as downstream sales arrangements, to accommodate our production volumes.

In our Eagle Ford Shale area, we are connected to the Camino Real oil gathering system and to the NuStar Energy system. The vast majority of our oil production flows on Camino Real, a 68-mile long pipeline with over 110,000 Bbls/d of capacity and a gravity bank that allows for oil blending to maintain attractive API levels. We have 80,000 Bbls/d of firm capacity on this oil system, of which we utilized an average of 54% during December 2015, 58% on average for the year. The system delivers oil to the Storey Oil Terminal on Highway 97 east of Cotulla, Texas, six miles southeast of Gardendale. From the Storey Terminal, oil can be pumped into Harvest's Arrowhead #1 and/or #2 pipelines, as well as the Plains All American Pipeline connection to the Gardendale Hub. Oil can also be loaded into trucks out of the Storey Terminal or out of the numerous central tank batteries throughout our field, providing additional deliverability, reliability and flexibility. We currently market our oil either at the Storey Terminal, Gardendale or at our central tank batteries under a combination of short and long-term contracts, ranging from monthly deals to a seven-year term sale. We currently receive a price premium for our Eagle Ford Shale oil relative to NYMEX/WTI, due primarily to exposure to waterborne crude markets on the Gulf Coast that price off the Louisiana Light Sweet crude index. With adequate takeaway capacity in the region and close proximity to the Gulf Coast refining complex, we do not anticipate any issues with marketing or delivering crude volumes from the Eagle Ford Shale.

Our Eagle Ford natural gas production flows on either the Camino Real gas gathering system or the Frio LaSalle Pipeline system. The majority of our produced gas flows on the Camino Real gas gathering system, which receives high-pressure, unprocessed wellhead gas into an 83-mile pipeline with capacity of 150-170 MMcf/d. The gas is then redelivered into interconnects with Energy Transfer, Enterprise, Regency and Eagle Ford Gathering. We currently have 125 MMcf/d of firm transportation capacity on Camino Real, of which we used an average of 76% during December 2015, and we have additional capacity available as needed. We have firm gas gathering, processing and transportation agreements on three of the interconnected gas pipelines downstream of the Camino Real system, with a minimum capacity of approximately 80 MMBtu/d and rights to increase firm capacity as necessary. In addition, gas produced from our northwest acreage position within the Eagle Ford area is connected to the Frio LaSalle Pipeline system, which provides access to firm H_2S treating and processing. Frio LaSalle can either return gas to the Camino Real system or, after processing, deliver to various Texas intrastate pipelines and a mix of interstates, such as Texas Eastern Transmission, Tennessee Gas Pipeline, and Transco. We market our physical gas to various purchasers at spot market prices.

In our Wolfcamp Shale area, we continue to leverage significant legacy gathering, processing and transportation infrastructure. For natural gas, we are connected to the West Texas Gas (WTG), DCP and Lucid Energy Group gathering systems, and we process a majority of our gas at the WTG Benedum & Sonora gas plants. We receive Waha pricing for our natural gas and Mont Belvieu pricing for our NGLs. "Waha pricing" refers to the published index price for spot and monthly physical natural gas purchases and sales made into interstate and intrastate pipelines at the outlet of the Waha header system and in the Waha vicinity in the Permian Basin in West Texas. “Mont Belvieu pricing” refers to the spot market price for NGLs delivered into the Mont Belvieu NGL processing and storage hub in Mont Belvieu, Texas. Our crude oil production facilities are connected to a third party oil gathering system that delivers to a Plains All American Pipeline at Owens Station in Reagan County, Texas, the Centurion Cline Shale Pipeline at Barnhart in Irion County, Texas and to the Magellan Longhorn pipeline in Crockett County, Texas. We sell our pipeline delivered crude to multiple purchasers under both short and long-term contracts at WTI-based pricing. We also maintain the capability to truck crude oil to those same purchasers under similarly-priced contracts to provide additional flow assurance. With new Permian Basin takeaway pipelines now online, we anticipate no limitations moving physical crude oil to market and expect regional pricing to remain correlated with NYMEX/WTI.

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In our Altamont area, the wax crude we produce is sold at the wellhead to multiple purchasers who transport the oil via truck to downstream refineries or to rail loading facilities. We sell most of the oil we produce in the basin to Salt Lake City refineries under long-term sales agreements that accommodate our production forecasts. We anticipate that expansions of Salt Lake City refineries will keep pace with basin-wide supply, and we will continue to develop new market solutions. Our produced natural gas is gathered and processed at the Altamont plant, a third-party-owned processing facility, under a long-term sales agreement that provides for residue gas return for operational use. In February 2016, we entered into a drilling partnership with a third party under which we will jointly develop 12 wells in Altamont. We will operate the wells and the transaction is expected to increase well-level returns on the jointly developed wells. We will begin drilling partnership wells in the first half of 2016.

In our Haynesville Shale area, our gathering facilities are connected to multiple gas takeaway pipeline systems, including Tennessee Gas Pipeline, Enterprise Acadian Gas Pipeline and Enterprise Stateline Gathering. We currently control approximately 145 MMcf/d of firm capacity on these pipelines, of which we used an average of 100% during December 2015. Ample interruptible capacity is available to effectively move our Haynesville gas to sales without limitation. Capacity obligations dropped substantially in early 2015 to approximately half of our year-end 2014 capacity levels. Currently, our Haynesville Shale gas is produced at close to pipeline specifications and requires only CO_2 removal before delivery into takeaway pipelines. We sell our physical gas production to a wide variety of purchasers at spot market prices under short-term sales agreements. Given the abundance of pipeline infrastructure in the region and the growing demand for natural gas in the Southeast, we do not anticipate any issues with production deliverability.

While most of our physical production is priced off spot market indices, we actively manage the volatility of spot market pricing through our risk management program. We enter into financial derivatives contracts on our oil, natural gas and a portion of our NGLs production to stabilize our cash flows, reduce the risk of downward commodity price movements and protect the economic assumptions associated with our capital investment program. We employ a disciplined risk management program that utilizes risk control processes and leverages commodity trading expertise of our staff. For a further discussion of these risk management activities and derivative contracts, see “Management’s Discussion and Analysis of Financial Condition” and “Results of Operations”.

Competitors

The exploration and production business is highly competitive in the search for and acquisition of additional oil and natural gas reserves and in the sale of oil, natural gas and NGLs. Our competitors include major and intermediate sized oil and natural gas companies, independent oil and natural gas operators and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include financial resources, price and contract terms, our ability to access drilling, completion and other equipment and our ability to hire and retain skilled personnel on a timely and cost effective basis. Ultimately, our future success in this business will be dependent on our ability to find and/or fund the acquisition of additional reserves at costs that yield acceptable returns on the capital invested.

Use of 3-D Seismic Data

We have an inventory of approximately 1,258 square miles of 3-D seismic data in our four areas which provides approximately 44% coverage over our leased acreage in those areas. We use the data to identify and optimize drilling locations and completion operations, field development plans and new resource targets. In the Wolfcamp and Altamont plays in particular, we utilize 3-D seismic technologies to help identify areas with natural fractures and use this information to help with the placement of future drill well locations that could result in higher productivity wells.

Regulatory Environment

Our oil and natural gas exploration and production activities are regulated at the federal, state and local levels in the United States. These regulations include, but are not limited to, those governing the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to various governmental safety and environmental regulations in the jurisdictions in which we operate.

Our operations under federal oil and natural gas leases are regulated by the statutes and regulations of the Department of the Interior (DOI) that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Office of Natural Resources Revenue within the DOI, which has promulgated valuation guidelines for the payment of royalties by producers. These laws and regulations affect the construction and operation of facilities, water disposal rights and drilling operations, among other items. In addition, we maintain insurance to limit exposure to sudden and accidental pollution liability exposures.

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Hydraulic Fracturing. Hydraulic fracturing is a process of pumping fluid and proppant (usually sand) under high pressure into deep underground geologic formations that contain recoverable hydrocarbons. These hydrocarbon formations are typically thousands of feet below the surface. The hydraulic fracturing process creates small fractures in the hydrocarbon formation. These fractures allow natural gas and oil to move more freely through the formation to the well and finally to the surface production facilities. We use hydraulic fracturing to maximize productivity of our oil and natural gas wells in our areas and our proved undeveloped oil and natural gas reserves will be developed using hydraulic fracturing. For the year ended December 31, 2015, we incurred costs of approximately $388 million associated with hydraulic fracturing.

Hydraulic fracturing fluid is typically composed of over 99% water and proppant, which is usually sand. The other 1% or less of the fluid is composed of additives that may contain acid, friction reducer, surfactant, gelling agent and scale inhibitor. We retain service companies to conduct such operations and we have worked with several service companies to evaluate, test and, where appropriate, modify our fluid design to reduce the use of chemicals in our fracturing fluid. We have worked closely with our service companies to provide voluntary and regulatory disclosure of our hydraulic fracturing fluids.

In order to protect surface and groundwater quality during the drilling and completion phases of our operations, we follow applicable industry practices and legal requirements of the applicable state oil and natural gas commissions with regard to well design, including requirements associated with casing steel strength, cement strength and slurry design. Our activities in the field are monitored by state and federal regulators. Key aspects of our field protection measures include: (i) pressure testing well construction and integrity, (ii) casing and cementing practices to ensure pressure management and separation of hydrocarbons from groundwater, and (iii) public disclosure of the contents of hydraulic fracturing fluids.

In addition to these measures, our drilling, casing and cementing procedures are designed to prevent fluid migration, which typically include some or all of the following:

- Our drilling process executes several repeated cycles conducted in sequence—drill, set casing, cement casing and then test casing and cement for integrity before proceeding to the next drilling interval.
- Conductor casing is drilled and cemented or driven in place. This string serves as the structural foundation for the well. Conductor casing is not necessary or required for all wells.
- Surface casing is set and is cemented in place. Surface casing is set on all wells. The purpose of the surface casing is to isolate and protect Underground Sources of Drinking Water (USDW) as identified by federal and state regulatory bodies. The surface casing and cement isolates wellbore materials from any potential contact with USDWs.
- Intermediate casing is set through the surface casing to a depth necessary to isolate abnormally pressured subsurface formations from normally pressured formations. Intermediate casing is not necessary or required for all wells. Our standard practices include cementing above any hydrocarbon bearing zone and performing casing pressure tests to verify the integrity of the casing and cement.
- Production casing is set through the surface and intermediate casing through the depth of the targeted producing formation. Our standard practices include pumping cement above the confining structure of the target zone and performing casing pressure tests and other tests to verify the integrity of the casing and cement. If any problems are detected, then appropriate remedial action is taken.
- With the casing set and cemented, a barrier of steel and cement is in place that is designed to isolate the wellbore from surrounding geologic formations. This barrier as designed mitigates against the risk of drilling or fracturing fluids entering potential sources of drinking water.

In addition to the required use of casing and cement in the well construction, we follow additional regulatory requirements and industry operating practices. These typically include pressure testing of casing and surface equipment and continuous monitoring of surface pressure, pumping rates, volumes of fluids and chemical concentrations during hydraulic fracturing operations. When any pressure differential outside the normal range of operations occurs, pumping is shut down until the cause of the pressure differential is identified and any required remedial measures are completed. Hydraulic fracturing fluid is delivered to our sites in accordance with Department of Transportation (DOT) regulations in DOT approved shipping containers using DOT transporters.

We also have procedures to address water use and disposal. This includes evaluating surface and groundwater sources, commercial sources, and potential recycling and reuse of treated water sources. When commercially and technically feasible, we use recycled or treated water. This practice helps mitigate against potential adverse impacts to other water supply sources. When using raw surface or groundwater, we obtain all required water rights or compensate owners for water consumption. We are evaluating additional treatment capability to augment future water supplies at several of our sites. During our drilling and completions operations, we manage waste water to minimize environmental risks and costs. Flowback water returned to the surface is typically contained in steel tanks or pits. Water that is not treated for reuse is typically piped or trucked to waste disposal injection wells, a number of which we operate. These wells are permitted through Underground Injection Control (UIC) program of the Safe Drinking Water Act. We also use commercial UIC permitted water injection facilities for flowback and produced water disposal.

We have not received regulatory citations or notice of suits related to our hydraulic fracturing operations for environmental concerns. We have not experienced a surface release of fluids associated with hydraulic fracturing that resulted in material financial exposure or significant environmental impact. Consistent with local, state and federal requirements, releases are reported to appropriate regulatory agencies and site restoration completed. No remediation reserve has been identified or anticipated as a result of hydraulic fracturing releases experienced to date.

Spill Prevention/Response Procedures. There are various state and federal regulations that are designed to prevent and respond to any spills or leaks resulting from exploration and production activities. In this regard, we maintain spill prevention control and countermeasures programs, which frequently include the installation and maintenance of spill containment devices designed to contain spill materials on location. In addition, we maintain emergency response plans to minimize potential environmental impacts in the event of a spill or leak or any significant hydraulic fracturing well control issue.

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Environmental
A description of our environmental remediation activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 9.
Employees
As of February 16, 2016, we had 665 full-time employees in the United States.
Executive Officers of the Registrant
Our executive officers as of February 16, 2016, are listed below.

Name	Office	Age
Brent J. Smolik	President, Chief Executive Officer and Chairman of the Board	54
Clayton A. Carrell	Executive Vice President and Chief Operating Officer	50
Joan M. Gallagher	Senior Vice President, Human Resources and Administrative Services	52
Dane E. Whitehead	Executive Vice President and Chief Financial Officer	54
Marguerite N. Woung-Chapman	Senior Vice President, General Counsel and Corporate Secretary	50

Brent J. Smolik
Mr. Smolik has been our President, Chief Executive Officer and Chairman of the Board since August 30, 2013, President and Chief Executive Officer of EP Energy LLC since May 2012 and previously served as Chairman of the Board of Managers of EPE Acquisition, LLC, from May 2012 to August 2013. He was previously Executive Vice President and a member of the Executive Committee of El Paso Corporation and President of our predecessor, EP Energy Corporation (a/k/a El Paso Exploration & Production Company) from November 2006 to May 2012. Mr. Smolik was President of ConocoPhillips Canada from April 2006 to October 2006. Prior to the Burlington Resources merger with ConocoPhillips, he was President of Burlington Resources Canada from September 2004 to March 2006. From 1990 to 2004, Mr. Smolik worked in various engineering and asset management capacities for Burlington Resources Inc., including the Chief Engineering role from 2000 to 2004. He was a member of Burlington's Executive Committee from 2001 to 2006. Mr. Smolik currently serves on the boards of directors of Cameron International Corporation, the American Exploration and Production Council and the Producers for American Crude Oil Exports. Mr. Smolik received his Bachelor of Science in Petroleum Engineering from Texas A&M University. As the President and Chief Executive Officer of EP Energy, Mr. Smolik is the only officer of our company to sit on the board.
Clayton A. Carrell
Mr. Carrell has been our Executive Vice President and Chief Operating Officer since August 30, 2013 and Executive Vice President and Chief Operating Officer of EP Energy LLC since May 2012. He was previously Senior Vice President, Chief Engineer of our predecessor, EP Energy Corporation (a/k/a El Paso Exploration & Production Company) from June 2010 to May 2012. Mr. Carrell joined El Paso Corporation in March 2007 as Vice President, Texas Gulf Coast Division. Prior to that, he was Vice President, Engineering & Operations at Peoples Energy Production from February 2001 to March 2007. Prior to joining Peoples Energy Production, Mr. Carrell worked at Burlington Resources and ARCO Oil and Gas Company from May 1988 to February 2001 in various domestic and international engineering and management roles. He serves on the Industry Board of the Texas A&M Petroleum Engineering Department and is a member of the Society of Petroleum Engineers. Mr. Carrell is also a member of the Center for Hearing and Speech Board of Trustees.
Joan M. Gallagher
Ms. Gallagher has been our Senior Vice President, Human Resources and Administrative Services, since August 30, 2013 and Senior Vice President, Human Resources and Administrative Services, of EP Energy LLC since May 2012. She was previously Vice President, Human Resources of El Paso Corporation from March 2011 to May 2012. From August 2005 until February 2011, she served as Vice President, Human Resources of our predecessor, EP Energy Corporation (a/k/a El Paso Exploration & Production Company). In that capacity, Ms. Gallagher had HR responsibility for El Paso Corporation's exploration and production business unit and from January 2010 to February 2011 she also had HR responsibilities for shared services and midstream. Prior to 2005, Ms. Gallagher served as Vice President and Chief Administrative Officer of Torch Energy Advisors Incorporated.

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Dane E. Whitehead

Mr. Whitehead has been our Executive Vice President and Chief Financial Officer since August 30, 2013 and Executive Vice President and Chief Financial Officer of EP Energy LLC since May 2012. He was previously Senior Vice President of Strategy and Enterprise Business Development and a member of the Executive Committee of El Paso Corporation from October 2009 to May 2012. He previously served as Senior Vice President and Chief Financial Officer of our predecessor, EP Energy Corporation (a/k/a El Paso Exploration & Production Company), from May 2006 to October 2009. He was the Vice President and Controller of Burlington Resources Inc. from June 2005 to March 2006. From January 2002 to May 2005 he was Senior Vice President and Chief Financial Officer of Burlington Resources Canada. He was a member of the Burlington Resources Executive Committee from 2000 to 2006. From 1984 to 1993, Mr. Whitehead was an independent accountant with Coopers and Lybrand. He is a member of the American Institute of Certified Public Accountants.

Marguerite N. Woung-Chapman

Ms. Woung-Chapman has been our Senior Vice President, General Counsel and Corporate Secretary since August 30, 2013 and Senior Vice President, General Counsel and Corporate Secretary of EP Energy LLC since May 2012. She was previously Vice President, Legal Shared Services, Corporate Secretary and Chief Governance Officer of El Paso Corporation from November 2009 to May 2012. Ms. Woung-Chapman was Vice President, Chief Governance Officer and Corporate Secretary at El Paso Corporation from May 2007 to November 2009 and from May 2006 to May 2007 served as General Counsel and Vice President of Rates and Regulatory Affairs for El Paso Corporation’s Eastern Pipeline Group. She served as General Counsel of El Paso Corporation’s Eastern Pipeline Group from April 2004 to May 2006. Ms. Woung-Chapman served as Vice President and Associate General Counsel of El Paso Merchant Energy from July 2003 to April 2004. Prior to that time, she held various legal positions with El Paso Corporation and Tenneco Energy starting in 1991.

Available Information

Our website is http://www.epenergy.com. We make available, free of charge on or through our website, our annual, quarterly and current reports, and any amendments to those reports, as soon as is reasonably possible after these reports are filed with the Securities and Exchange Commission (SEC). Information about each of our Board members, each of our Board’s standing committee charters, and our Corporate Governance Guidelines as well as a copy of our Code of Conduct are also available, free of charge, through our website. Information contained on our website is not part of this report.

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ITEM 1A. RISK FACTORS

Risks Related to Our Business and Industry

The prices for oil, natural gas and NGLs are highly volatile and sustained lower prices have adversely affected, and may continue to adversely affect, our business, results of operations, cash flows and financial condition.

Our success depends upon the prices we receive for our oil, natural gas and NGLs. These commodity prices historically have been highly volatile and are likely to continue to be volatile in the future, especially given current global geopolitical and economic conditions. During the second half of 2014, NYMEX/WTI oil prices fell from in excess of $100 per Bbl to below $50 per Bbl. NYMEX/WTI oil prices continued to decline in 2015 and early 2016, reaching prices below $30.00 per Bbl. There is a risk that commodity prices could remain depressed for a sustained period. The prices for oil, natural gas and NGLs are subject to a variety of factors that are outside of our control, which include, among others:

- regional, domestic and international supply of, and demand for, oil, natural gas and NGLs;
- oil, natural gas and NGLs inventory levels in the United States;
- political and economic conditions domestically and in other oil and natural gas producing countries, including the current conflicts in the Middle East and conditions in Africa, Russia and South America;
- actions of OPEC and other state-controlled oil companies relating to oil, natural gas and NGLs price and production controls;
- wars, terrorist activities and other acts of aggression;
- weather conditions and weather patterns;
- technological advances affecting energy consumption and energy supply;
- adoption of various energy efficiency and conservation measures;
- the price and availability of supplies of alternative energy sources;
- the price and quantity of U.S. imports and exports of oil, natural gas, including liquefied natural gas, and NGLs;
- volatile trading patterns in capital and commodity-futures markets;
- the strengthening and weakening of the U.S. dollar relative to other currencies;
- changes in domestic governmental regulations, administrative and/or agency actions, and taxes, including potential restrictive regulations associated with hydraulic fracturing operations;
- changes in the costs of exploring for, developing, producing, transporting, processing and marketing oil, natural gas and NGLs;
- availability, proximity and cost of commodity processing, gathering and transportation and refining capacity;
- perceptions of customers on the availability and price volatility of our products, particularly customers' perception of the volatility of oil and natural gas prices over the longer term; and
- variations between product prices at sales points and applicable index prices.

The negative impact of low commodity prices on our cash flows could limit our cash available for capital expenditures and reduce our drilling opportunities. Any resulting decreases in production could result in an additional shortfall in our expected cash flows and require us to further reduce our capital spending or borrow funds to cover any such shortfall. In addition to reducing our cash flows, the prolonged and substantial decline in commodity prices has and could continue to negatively impact our proved oil and natural gas reserves and could negatively impact the amount of oil and natural gas that we can produce economically in the future. Commodity prices also affect our ability to access funds under our reserve-based revolving credit facility (the RBL Facility) and through the capital markets. The amount available for borrowing under the RBL Facility is subject to a borrowing base, which is determined by our lenders taking into account our proved reserves, and is subject to periodic redeterminations (in April and November) based on pricing models determined by the lenders at such time. Declines in oil, natural gas and NGLs prices have and could continue to adversely impact the value of our proved reserves and,

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in turn, the bank pricing used by our lenders to determine our borrowing base. Upon redetermination, we would be required to repay amounts outstanding under our credit facility should they exceed the redetermined borrowing base. Any of these factors could further negatively impact our liquidity, our ability to replace our production and our future rate of growth. On the other hand, increases in commodity prices may be offset by increases in drilling costs, production taxes and lease operating costs that typically result from any increase in commodity prices. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

We have significant capital programs in our business that may require us to access capital markets, and any inability to obtain access to the capital markets in the future at competitive rates, or any negative developments in the capital markets, could have a material adverse effect on our business.

We have significant capital programs in our business, which may require us to access the capital markets. Since we are rated below investment grade, our ability to access the capital markets or the cost of capital could be negatively impacted in the future, which could require us to forego capital opportunities or could make us less competitive in our pursuit of growth opportunities, especially in relation to many of our competitors that are larger than us or have investment grade ratings. There is a risk that our below investment credit rating may be further adversely affected in the future as the credit rating agencies review their general credit requirements in light of the sustained lower commodity price environment as well as review our leverage, liquidity, credit profile and potential transactions. For example, on February 3, 2016, Moody's Investors Service downgraded EP Energy LLC's Corporate Family Rating to B3 from Ba3 with a negative outlook, and on February 9, 2016, Standard & Poor's downgraded the Corporate Family Rating from BB- to B with a stable outlook. Reductions in our credit rating could have a negative impact on us, such as increasing our operating costs through having to post incremental collateral for our transportation contract obligations.

In addition, the credit markets for companies in the energy sector in recent years have experienced a period of turmoil and upheaval as commodity prices have significantly declined. These circumstances and events have led to reduced credit availability, tighter lending standards and higher interest rates on loans for companies in the energy industry, especially non-investment grade companies. While we cannot predict the future condition of the credit markets, future turmoil in the credit markets could have a material adverse effect on our business, liquidity, financial condition and cash flows, particularly if our ability to borrow money from lenders or access the capital markets to finance our operations were to be impaired. In April 2015, we extended the maturity of the RBL Facility to May 2019, provided that we retire or refinance our 2018 and 2019 secured notes and term loans at least six months prior to their maturity. In mid-2015, we refinanced our $750 million secured notes and we will be required to retire or refinance our remaining $500 million senior secured term loans due 2018 by November 2017 and $150 million senior secured term loans due 2019 by November 2018.

Although we believe that the banks participating in the RBL Facility have adequate capital and resources, we can provide no assurance that all of those banks will continue to operate as going concerns in the future. If any of the banks in our lending group were to fail, it is possible that the borrowing capacity under the RBL Facility would be reduced. In the event of such reduction, we could be required to obtain capital from alternate sources in order to finance our capital needs. Our options for addressing such capital constraints would include, but not be limited to, obtaining commitments from the remaining banks in the lending group or from new banks to fund increased amounts under the terms of the RBL Facility, and accessing the public and private capital markets. In addition, we may delay certain capital expenditures to ensure that we maintain appropriate levels of liquidity. If it became necessary to access additional capital, any such alternatives could have terms less favorable than the terms under the RBL Facility, which could have a material adverse effect on our business, results of operations, financial condition and cash flows.

We have significant existing debt which requires us to dedicate a substantial portion of our cash flows to service our debt payment obligations, as well as reduces our flexibility to respond to changing circumstances.

We have significant debt and debt service obligations. This requires us to dedicate a substantial portion of our cash flow from operations to debt service payments, thereby reducing the availability of cash for working capital, capital expenditures, acquisitions or general corporate purposes. In addition, these debt levels expose us to more liquidity, breach of covenants and default risks, especially during times of financial volatility and reduced commodity prices. It similarly reduces our flexibility to compete on future acquisitions.

The success of our business depends upon our ability to find and replace reserves that we produce.
Similar to our competitors, we have a reserve base that is depleted as it is produced. Unless we successfully replace the reserves that we produce, our reserves will decline, which will eventually result in a decrease in oil and natural gas production and lower revenues and cash flows from operations. We historically have replaced reserves through both drilling and acquisitions. The business of exploring for, developing or acquiring reserves requires substantial capital expenditures. If we do not continue to make significant capital expenditures (for any reason, including our access to capital resources becoming

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limited) or if our exploration, development and acquisition activities are unsuccessful, we may not be able to replace the reserves that we produce, which would negatively impact us. As a result, our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs or at all. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, results of operations and financial condition would be materially adversely affected.

Our oil and natural gas drilling and producing operations involve many risks, and our production forecasts may differ from actual results.

Our success will depend on our drilling results. Our drilling operations are subject to the risk that (i) we may not encounter commercially productive reservoirs or (ii) if we encounter commercially productive reservoirs, we either may not fully recover our investments or our rates of return will be less than expected. Our past performance should not be considered indicative of future drilling performance. For example, we have acquired acreage positions in domestic oil and natural gas shale areas for which we plan to incur substantial capital expenditures over the next several years. It remains uncertain whether we will be successful in developing the reserves in these regions. Our success in such areas will depend in part on our ability to continue to successfully transfer our experiences from existing areas into these new shale plays. As a result, there remains uncertainty on the results of our drilling programs, including our ability to realize proved reserves or to earn acceptable rates of return on our drilling programs. From time to time, we provide forecasts of expected quantities of future production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Our forecasts could be different from actual results and such differences could be material.

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. In addition, the results of our exploratory drilling in new or emerging areas are more uncertain than drilling results in areas that are developed and have established production. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may increase the cost of, or curtail, delay or cancel drilling operations, including the following:

- unexpected drilling conditions;
- delays imposed by or resulting from compliance with regulatory and contractual requirements;
- unexpected pressure or irregularities in geological formations;
- equipment failures or accidents;
- fracture stimulation accidents or failures;
- adverse weather conditions;
- declines in oil and natural gas prices;
- surface access restrictions with respect to drilling or laying pipelines;
- shortages (or increases in costs) of water used in hydraulic fracturing, especially in arid regions or regions that have been experiencing severe drought conditions;
- shortages or delays in the availability of, increases in the cost of, or increased competition for, drilling rigs and crews, fracture stimulation crews, equipment, pipe, chemicals and supplies and transportation, gathering, processing, treating or other midstream services; and
- limitations or reductions in the market for oil and natural gas.

Additionally, the occurrence of certain of these events, particularly equipment failures or accidents, could impact third parties, including persons living in proximity to our operations, our employees and employees of our contractors, leading to possible injuries or death or significant property damage. As a result, we face the possibility of liabilities from these events that could materially adversely affect our business, results of operations and financial condition.

In addition, uncertainties associated with enhanced recovery methods may not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate and we may be unable to realize an acceptable return on our

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investments in certain of our projects. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict.

Our drilling locations are scheduled to be drilled over a number of years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has identified and scheduled potential drilling locations as an estimate of our future multi-year drilling activities on our existing acreage. All of our potential drilling locations, particularly our potential drilling locations for oil, represent a significant part of our strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil, natural gas and NGLs prices, costs and drilling results. Because of these uncertainties, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells where a final investment decision has been made to drill within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Drilling locations that we decide to drill may not yield oil, natural gas or NGLs in commercially viable quantities.

We describe potential drilling locations and our plans to explore those potential drilling locations in this Annual Report on Form 10-K. These potential drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively, prior to drilling, whether oil, natural gas or NGLs will be present or, if present, whether oil, natural gas or NGLs will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil, natural gas or NGLs exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our other identified drilling locations. Further, initial production rates reported by us or other operators may not be indicative of future or long-term production rates. The cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and increase our proved reserves and production. In 2015, we spent total capital including acquisitions of $1.3 billion. We have established a capital budget for 2016 of approximately $500 million to $900 million and we intend to rely on cash flow from operating activities, available cash and borrowings under the RBL Facility as our primary sources of liquidity. For a discussion of liquidity, see Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources”. We also may engage in asset sale transactions to, among other things, fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. There can be no assurance that such sources will be sufficient to fund our exploration, development and acquisition activities. If our revenues and cash flows continue to decrease in the future as a result of a sustained decline in commodity prices or a reduction in production levels, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to increase or even maintain our reserves and production levels.

Our future revenues, cash flows and spending levels are subject to a number of factors, including commodity prices, the level of production from existing wells and our success in developing and producing new wells. Further, our ability to access funds under the RBL Facility is based on a borrowing base, which is subject to periodic redeterminations (in April and November) based on our proved reserves and prices that will be determined by our lenders using the bank pricing prevailing at such time. If the prices for oil and natural gas decline, if we have a downward revision in estimates of our proved reserves, or if we sell additional oil and natural gas reserves, our borrowing base may be reduced.

Our ability to access the capital markets and complete future asset monetization transactions is also dependent upon oil, natural gas and NGLs prices, in addition to a number of other factors, some of which are outside our control. These factors include, among others, domestic and global economic conditions and conditions in the domestic and global financial markets.

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Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures or refinance our debt obligations as they come due, any of which could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Our use of derivative financial instruments could result in financial losses or could reduce our income.

We use fixed price financial options and swaps to mitigate our commodity price, basis and interest rate exposures. However, we do not typically hedge all of these exposures, and typically do not hedge any of these exposures beyond several years. Currently, our derivative contracts (primarily fixed price swaps), will allow us to realize a weighted average price of $80.29 per barrel on 18 MMBbls of oil and $4.20 per MMBtu on 7 TBtu of natural gas in 2016. However, based on the current price environment, our ability to enter into hedges that provide meaningful protection of our future cash flows is limited. As a result, we have substantial commodity price and basis exposure since our business has multi-year drilling programs for our proved reserves and unproved resources, particularly as our existing hedges roll off.

The derivative contracts we enter into to mitigate commodity price risk are not designated as accounting hedges and are therefore marked to market. As a result, we still experience volatility in our revenues and net income as a result of changes in commodity prices, counterparty non-performance risks, correlation factors and changes in the liquidity of the market. Furthermore, the valuation of these financial instruments involves estimates that are based on assumptions that could prove to be incorrect and result in financial losses. Although we have internal controls in place that impose restrictions on the use of derivative instruments, there is a risk that such controls will not be complied with or will not be effective, and we could incur substantial losses on our derivative transactions. The use of derivatives, to the extent they require collateral posting with our counterparties, could impact our working capital and liquidity when commodity prices or interest rates change.

To the extent we enter into derivative contracts to manage our commodity price, basis and interest rate exposures, we may forego the benefits we could otherwise experience if such prices and rates were to change favorably and we could experience losses to the extent that these prices and rates were to increase above the fixed price. In addition, these hedging arrangements also expose us to the risk of financial loss in the following circumstances, among others:

- when production is less than expected or less than we have hedged;
- when the counterparty to the hedging instrument defaults on its contractual obligations;
- when there is an increase in the differential between the underlying price in the hedging instrument and actual prices received; and
- when there are issues with respect to legal enforceability of such instruments.

Our derivative counterparties are typically large financial institutions. We are subject to the risk of loss on our derivative instruments as a result of non-performance by counterparties to the terms of their obligations. The risk that a counterparty may default on its obligations is heightened by the continued significant decline in commodity prices. The ability of our counterparties to meet their obligations to us on hedge transactions could reduce our revenue from hedges at a time when we are also receiving a lower price for our oil and natural gas sales. As a result, our business, results of operations and financial condition could be materially adversely affected.

The derivatives reform legislation adopted by the U.S. Congress could have a negative impact on our ability to hedge risks associated with our business.

In 2010, Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which, among other matters, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market. The Dodd-Frank Act mandates that the Commodity Futures Trading Commission (CFTC), adopt rules and regulations implementing the Dodd-Frank Act and further defining certain terms used in the Dodd-Frank Act. The Dodd-Frank Act also required the CFTC and the prudential banking regulators to establish requirements for clearing of swaps and margin requirements for uncleared swaps. Although there is an exception from swap clearing and trade execution requirements for commercial end-users that meet certain conditions (the End-User Exception), and although there is also an exception from the margin requirements for swaps where one of the parties satisfies the End-User Exception, certain market participants, including most if not all of our counterparties, will be required to clear many of their swap transactions with entities that do not satisfy the End-User Exception, will have to transact many of their swaps on swap execution facilities or designated contract markets, rather than over-the-counter on a bilateral basis, and will have to comply with the margin requirements of the applicable swap execution facility or designated contract market in connection with such swaps and will

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have to comply with statutorily mandated margin requirements in connection with any uncleared swaps where an exception to the margin requirements is not available. These requirements may increase the cost to our counterparties of hedging the swap positions they enter into with us, and thus may increase the cost to us of entering into our hedges. The changes in the regulation of swaps may result in certain market participants deciding to curtail or cease their derivatives activities. While many regulations have been promulgated and are already in effect, the rulemaking and implementation process is ongoing, and the ultimate effect of the adopted rules and regulations and any future rules and regulations on our business remains uncertain.

We qualify as a "non-financial entity" for purposes of the End-User Exception and satisfy the other requirements of the End-User Exception and intend to utilize the End-User Exception. As a result, our swaps will not be subject to mandatory clearing and our uncleared swaps will not be subject to statutorily mandated margin requirements; therefore, we do not expect to clear our swaps and our swap transactions will not be subject to the margin requirements imposed by derivatives clearing organizations or by the Dodd-Frank Act.

A rule adopted under the Dodd-Frank Act imposing position limits in respect of transactions involving certain commodities, including oil and natural gas was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia, U.S. District Judge Robert L. Wilkins on September 28, 2012. The CFTC appealed this decision and on November 5, 2013, filed a consensual motion to dismiss its appeal. The same day, the CFTC proposed a new position limits rule (the 2013 Proposed Rule) which would limit trading in New York Mercantile Exchange (NYMEX) contracts for Henry Hub Natural Gas, Light Sweet Crude Oil, New York Harbor Ultra-Low Sulfur No. 2 Diesel and Reformulated Blendstock for Oxygen Blending Gasoline and other futures and swap contracts that are economically equivalent to such NYMEX contracts. The CFTC received comments on, but has not adopted the 2013 Proposed Rule. On September 22, 2015 the CFTC proposed revisions to the 2013 Proposed Rule (the 2015 Proposal). Comments on the 2015 Proposal were due on November 13, 2015. We cannot predict whether or when the 2013 Proposed Rule, as modified by the 2015 Proposal, will be adopted or the effect of such rule on our business. The Dodd-Frank Act and the rules promulgated thereunder could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. 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 contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

Estimating our reserves involves uncertainty, our actual reserves will likely vary from our estimates, and negative revisions to our reserve estimates in the future could result in decreased earnings and/or losses and impairments.

All estimates of proved reserves are determined according to the rules prescribed by the SEC. Our reserve information is prepared internally and is audited by an independent petroleum engineering consultant. There are numerous uncertainties involved in estimating proved reserves, which may result in our estimates varying considerably from actual results. Estimating quantities of proved reserves is complex and involves significant interpretation and assumptions with respect to available geological, geophysical and engineering data, including data from nearby producing areas. It also requires us to estimate future economic factors, such as commodity prices, production costs, plugging and abandonment costs, severance, ad valorem and excise taxes, capital expenditures, workover and remedial costs, and the assumed effect of governmental regulation. Due to a lack of substantial production data, there are greater uncertainties in estimating proved undeveloped reserves and proved developed non-producing reserves. There is also greater uncertainty of estimating proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise. Furthermore, estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices (including commodity prices and the cost of oilfield services), economic conditions and government restrictions and regulations. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revision of that estimate. Therefore, our reserve information represents an estimate and is often different from the quantities of oil and natural gas that are ultimately recovered or proven recoverable.

The SEC rules require the use of a 10% discount factor for estimating the value of our future net cash flows from reserves and the use of a 12-month average price. This discount factor may not necessarily represent the most appropriate discount factor, given our costs of capital, actual interest rates and risks faced by our exploration and production business, and the average price will not generally represent the market prices for oil and natural gas over time. Any significant change in commodity prices could cause the estimated quantities and net present value of our reserves to differ and these differences could be material. You should not assume that the present values referred to in this Annual Report on Form 10-K represent the current market value of our estimated oil and natural gas reserves. Finally, the timing of the production and the expenses related

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to the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value.

We account for our activities under the successful efforts method of accounting. Changes in the estimated fair value of these reserves could result in a write-down in the carrying value of our oil and natural gas properties, which could be substantial and could have a material adverse effect on our net income and stockholders' equity. Changes in the estimated fair value of these reserves could also result in increasing our depreciation, depletion and amortization rates, which could decrease earnings.

A portion of our proved reserves are undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling operations. In addition, because our proved reserve base consists primarily of unconventional resources, the costs of finding, developing and producing those reserves may require capital expenditures that are greater than more conventional resource plays. Our estimates of proved reserves assume that we can and will make these expenditures and conduct these operations successfully. However, future events, including commodity price changes and our ability to access capital markets, may cause these assumptions to change.

Our business is subject to competition from third parties, which could negatively impact our ability to succeed.

The oil, natural gas and NGLs businesses are highly competitive. We compete with third parties in the search for and acquisition of leases, properties and reserves, as well as the equipment, materials and services required to explore for and produce our reserves. There has been intense competition for the acquisition of leasehold positions, particularly in many of the oil and natural gas shale plays. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to fund and consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil properties. Similarly, we compete with many third parties in the sale of oil, natural gas and NGLs to customers, some of which have substantially larger market positions, marketing staff and financial resources than us. Our competitors include major and independent oil and natural gas companies, as well as financial services companies and investors, many of which have financial and other resources that are substantially greater than those available to us. Many of these companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices.

Furthermore, there is significant competition between the oil and natural gas industry and other industries producing energy and fuel, which may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the U.S. government. It is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which could negatively impact our competitive position.

Our industry is cyclical, and historically there have been shortages of drilling rigs, equipment, supplies or qualified personnel. A sustained decline in commodity prices can also reduce the number of service providers for such drilling rigs, equipment, supplies or qualified personnel, contributing to or also resulting in the shortages. Alternatively, during periods of high prices, the cost of rigs, equipment, supplies and personnel can fluctuate widely and availability may be limited. These services may not be available on commercially reasonable terms or at all. We cannot predict the extent to which these conditions will exist in the future or their timing or duration. The high cost or unavailability of drilling rigs, equipment, supplies, personnel and other oil field services could significantly decrease our profit margins, cash flows and operating results and could restrict our ability to drill the wells and conduct the operations that we currently have planned and budgeted or that we may plan in the future. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Our business is subject to operational hazards and uninsured risks that could have a material adverse effect on our business, results of operations and financial condition.

Our oil and natural gas exploration and production activities are subject to all of the inherent risks associated with drilling for and producing natural gas and oil, including the possibility of:

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- Adverse weather conditions, natural disasters, and/or other climate related matters—including extreme cold or heat, lightning and flooding, fires, earthquakes, hurricanes, tornadoes and other natural disasters. Although the potential effects of climate change on our operations (such as hurricanes, flooding, etc.) are uncertain at this time, changes in climate patterns as a result of global emissions of greenhouse gas (GHG) could also have a negative impact upon our operations in the future, particularly with regard to any of our facilities that are located in or near coastal regions;
- Acts of aggression on critical energy infrastructure—including terrorist activity or “cyber security” events. We are subject to the ongoing risk that one of these incidents may occur which could significantly impact our business operations and/or financial results. Should one of these events occur in the future, it could impact our ability to operate our drilling and exploration processes, our operations could be disrupted, and/or property could be damaged resulting in substantial loss of revenues, increased costs to respond or other financial loss, damage to reputation, increased regulation and litigation and/or inaccurate information reported from our exploration and production operations to our financial applications, to our customers and to regulatory entities; and
- Other hazards—including the collision of third-party equipment with our infrastructure; explosions, equipment malfunctions, mechanical and process safety failures, well blowouts, formations with abnormal pressures and collapses of wellbore casing or other tubulars; events causing our facilities to operate below expected levels of capacity or efficiency; uncontrollable flows of natural gas, oil, brine or well fluids, release of pollution or contaminants (including hydrocarbons) into the environment (including discharges of toxic gases or substances) and other environmental hazards.

Each of these risks could result in (i) damage to and destruction of our facilities; (ii) damage to and destruction of property, natural resources and equipment; (iii) injury or loss of life; (iv) business interruptions while damaged energy infrastructure is repaired or replaced; (v) pollution and other environmental damage; (vi) regulatory investigations and penalties; and (vii) repair and remediation costs. Any of these results could cause us to suffer substantial losses.

While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels and limits on our maximum recovery and do not cover all risks. For example, from time to time, we may not carry, or may be unable to obtain, on terms that we find acceptable and/or reasonable, insurance coverage for certain exposures, including, but not limited to certain environmental exposures (including potential environmental fines and penalties), business interruption and, named windstorm/hurricane exposures and, in limited circumstances, certain political risk exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their insurance coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance, will not compensate us fully for our losses. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Some of our operations are subject to joint ventures or operations by third parties, which could negatively impact our control over these operations and have a material adverse effect on our business, results of operations, financial condition and prospects.

A small portion of our operations and interests are operated by third-party working interest owners. In such cases, (i) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (ii) we cannot control the amount of capital expenditures that we are required to fund with respect to properties, (iii) we are dependent on third parties to fund their required share of capital expenditures and (iv) we may have restrictions or limitations on our ability to sell our interests in these jointly owned assets.

The insolvency of an operator of our properties, the failure of an operator of our properties to adequately perform operations or an operator’s breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner. As a result, the success and timing of our drilling and development activities on properties operated by others and the economic results derived therefrom depends 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. Finally, an operator of our properties may have the right, if another non-operator fails to pay its share of costs, to require us to pay our proportionate share of the defaulting party's share of costs.

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We currently sell most of our oil production to a limited number of significant purchasers. The loss of one or more of these purchasers, if not replaced, could reduce our revenues and have a material adverse effect on our financial condition or results of operations.

For the year ended December 31, 2015, five purchasers accounted for approximately 74% of our oil revenues. We depend upon a limited number of significant purchasers for the sale of most of our production. The loss of any of these customers, should we be unable to replace them, could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production.

We are subject to a complex set of laws and regulations that regulate the energy industry for which we have to incur substantial compliance and remediation costs.

Our operations, and the energy industry in general, are subject to a complex set of federal, state and local laws and regulations over the following activities, among others:

- the location of wells;
- methods of drilling and completing wells;
- allowable production from wells;
- unitization or pooling of oil and gas properties;
- spill prevention plans;
- limitations on venting or flaring of natural gas;
- disposal of fluids used and wastes generated in connection with operations;
- access to, and surface use and restoration of, well properties;
- plugging and abandoning of wells, even if we no longer own and/or operate such wells;
- air quality and emissions, noise levels and related permits;
- gathering, transportation and marketing of oil and natural gas (including NGLs);
- taxation; and
- competitive bidding rules on federal and state lands.

Generally, the regulations have become more stringent and have imposed more limitations on our operations and, as a result, have caused us to incur more costs to comply. Many required approvals are subject to considerable discretion by the regulatory agencies with respect to the timing and scope of approvals and permits issued. If permits are not issued, or if unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct our operations as planned or at all. Delays in obtaining regulatory approvals or permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with excessive conditions or costs could have a material negative impact on our operations and financial results. We may also incur substantial costs in order to maintain compliance with these existing laws and regulations, including costs to comply with new and more extensive reporting and disclosure requirements. Failure to comply with such requirements may result in the suspension or termination of operations and may subject us to criminal as well as civil and administrative penalties. We are exposed to fines and penalties to the extent that we fail to comply with the applicable laws and regulations, as well as the potential for limitations to be imposed on our operations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Also, some of our assets are located and operate on federal, state, local or tribal lands and are typically regulated by one or more federal, state or local agencies. For example, we have drilling and production operations that are located on federal lands, which are regulated by the U.S. Department of the Interior (DOI), particularly by the Bureau of Land Management (BLM). We also have operations on Native American tribal lands, which are regulated by the DOI, particularly by the Bureau of Indian Affairs (BIA), as well as local tribal authorities. Operations on these properties are often subject to additional regulations and compliance obligations, which can delay our access to such lands and impose additional compliance costs. There are also various laws and regulations that regulate various market practices in the industry, including antitrust laws and

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laws that prohibit fraud and manipulation in the markets in which we operate. The authority of the Federal Trade Commission and the CFTC to impose penalties for violations of laws or regulations has generally increased over the last few years.

We are exposed to the credit risk of our counterparties, contractors and suppliers.

We have significant credit exposure related to our sales of physical commodities, payments to contractors and suppliers, hedging activities and to the non-operating working interest owners who are counterparties to our operating agreements. If our counterparties fail to make payments/or perform within the time required under our contracts, our results of operations and financial condition could be materially adversely affected. Although we maintain strict credit policies and procedures and credit insurance in some cases, they may not be adequate to fully eliminate the credit risk associated with our counterparties, contractors and suppliers.

We are exposed to the performance risk of our key contractors and suppliers.

As an owner of drilling and production facilities with significant capital expenditures in our business, we rely on contractors for certain construction, drilling and completion operations and we rely on suppliers for key materials, supplies and services, including steel mills, pipe and tubular manufacturers and oil field service providers. We also rely upon the services of other third parties to explore or analyze our prospects to determine a method in which the prospects may be developed in a cost-effective manner. There is a risk that such contractors and suppliers may experience credit and performance issues triggered by a sustained low commodity price environment that could adversely impact their ability to perform their contractual obligations with us, including their performance and warranty obligations. This could result in delays or defaults in performing such contractual obligations and increased costs to seek replacement contractors, each of which could negatively impact us.

The Sponsors and other legacy investors own approximately 85 percent of the equity interests in us and may have conflicts of interest with us and or public investors.

Investment funds affiliated with, and one or more co-investment vehicles controlled by, our Sponsors and other legacy investors collectively own approximately 85 percent of our equity interests and such persons or their designees hold substantially all of the seats on our board of directors. As a result, the Sponsors and such other investors have control over our decisions to enter into certain corporate transactions and have the ability to prevent any transaction that typically would require the approval of stockholders, regardless of whether holders of our notes or stock believe that any such transactions are in their own best interests. For example, the Sponsors and other legacy investors could collectively cause us to make acquisitions that increase the amount of our indebtedness or to sell assets, or could cause us to issue additional equity or declare dividends or other distributions to our equity holders. So long as investment funds affiliated with the Sponsors and other such investors continue to indirectly own a majority of the outstanding shares of our equity interests or otherwise control a majority of our board of directors, these investors will continue to be able to strongly influence or effectively control our decisions. The indentures governing the notes and the credit agreements governing the RBL Facility and our senior secured term loan permit us, under certain circumstances, to pay advisory and other fees, pay dividends and make other restricted payments to the Sponsors and other investors, and the Sponsors and such other investors or their respective affiliates may have an interest in our doing so. Additionally, the Sponsors and other legacy investors are in the business of making investments in companies and may from time to time acquire and hold interests in businesses that compete directly or indirectly with us or that supply us with goods and services. These persons may also pursue acquisition opportunities that may be complementary to (or competitive with) our business, and as a result those acquisition opportunities may not be available to us. In addition, the Sponsors' and other investors' interests in other portfolio companies could impact our ability to pursue acquisition opportunities.

The loss of the services of key personnel could have a material adverse effect on our business.

Our executive officers and other members of our senior management have been a critical element of our success. These individuals have substantial experience and expertise in our business and have made significant contributions to its growth and success. We do not have key man or similar life insurance covering our executive officers and other members of senior management. We have entered into employment agreements with each of our executive officers, including Brent J. Smolik, our President and Chief Executive Officer, Dane E. Whitehead, our Executive Vice President and Chief Financial Officer and Clayton A. Carrell, our Executive Vice President and Chief Operating

Officer, but these agreements do not guarantee that these executives will remain with us. The unexpected loss of services of one or more of our executive officers or members of senior management could have a material adverse effect on our business.

Our business requires the retention and recruitment of a skilled workforce and the loss of employees and skilled labor shortages could result in the inability to implement our business plans and could negatively impact our profitability.

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Our business requires the retention and recruitment of a skilled workforce including engineers, technical personnel, geoscientists, project managers, land personnel and other professionals. We compete with other companies in the energy and other industries for this skilled workforce. We have developed company-wide compensation and benefit programs that are designed to be competitive among our industry peers and that reflect market-based metrics as well as incentives to create alignment with the Sponsors and other investors, but there is a risk that these programs and those in the future will not be successful in retaining and recruiting these professionals or that we could experience increased costs. If we are unable to (i) retain our current employees, (ii) successfully complete our knowledge transfer and/or (iii) recruit new employees of comparable knowledge and experience, our business, results of operations and financial condition could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

We may be affected by skilled labor shortages, which we have from time-to-time experienced. There is also a risk that staff reductions that have, and may continue to accompany the downturn in the industry may adversely impact our ability to conduct our business or respond to new business opportunities. Skilled labor shortages could negatively impact the productivity and profitability of certain projects. Our inability to bid on new and attractive projects, or maintain productivity and profitability on existing projects due to the limited supply of skilled workers and/or increased labor costs could have a material adverse effect on our business, results of operation and financial condition.

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques, the results of which are subject to drilling and completion technique risks, and drilling results may not meet our expectations for reserves or production.

Many of our operations involve utilizing the latest horizontal drilling and completion techniques in order to maximize cumulative recoveries and therefore optimize our returns. Drilling risks that we face while include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently longer period. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and natural gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our business, results of operations and financial condition may be materially adversely affected.

Our business depends on access to oil, natural gas and NGLs processing, gathering and transportation systems and facilities.

The marketability of our oil, natural gas and NGLs production depends in large part on the operation, availability, proximity, capacity and expansion of processing, gathering and transportation facilities owned by third parties. We can provide no assurance that sufficient processing, gathering and/or transportation capacity will exist or that we will be able to obtain sufficient processing, gathering and/or transportation capacity on economic terms. A lack of available capacity on processing, gathering and transportation 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 facilities for an extended period of time could negatively impact 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.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

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Water currently is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. In times of drought, we may be subject to local or state restrictions on the amount of water we procure to help protect local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce our reserves, which could have an adverse effect on our financial condition, results of operations and cash flows.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our operations. Productive zones frequently contain water that must be removed in order for the oil and natural gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce oil and natural gas in commercial quantities. The produced water must be transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability. Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

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 or at all. Any acquisition, including any completed or future acquisition, involves potential risks, including, among others:

- we 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 and for which contractual protections prove inadequate or that exceed our estimates;
- we may acquire properties that are subject to burdens on title that we were not aware of at the time of acquisition that interfere with our ability to hold the property for production and for which contractual protections prove inadequate;
- 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;
- we may encounter disruption to our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls, procedures and policies;
- we may issue (or assume) additional equity or debt securities or debt instruments in connection with future acquisitions, which may affect our liquidity or financial leverage;
- we may make mistaken assumptions about costs, including synergies related to an acquired business;
- we may encounter difficulties in complying with regulations, such as environmental regulations, and managing risks related to an acquired business;

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- we may encounter limitations on rights to indemnity from the seller;
- we may make mistaken assumptions about the overall costs of equity or debt used to finance any such acquisition;
- we may encounter difficulties in entering markets in which we have no or limited direct prior experience and where competitors in such markets have stronger expertise and/or market positions;
- we may potentially lose key customers; and
- we may lose key employees and/or encounter costly litigation resulting from the termination of those employees.

Any of the above risks could significantly impair our ability to manage our business, complete or effectively integrate acquisitions and may have a material adverse effect on our business, results of operations and financial condition.

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

Although many of our reserves are located on leases that are held-by-production or held by continuous development, we do have provisions in a number of our leases that provide for the lease to expire unless certain conditions are met, such as drilling having commenced on the lease or production in paying quantities having been obtained within a defined time period. If commodity prices remain low or we are unable to allocate sufficient capital to meet these obligations in a declining commodity price environment given capital reductions, there is a risk that some of our existing proved reserves and some of our unproved inventory/acreage could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in impairment of remaining costs, a reduction in our reserves and our growth opportunities (or the incurrence of significant costs) and therefore could have a material adverse effect on our financial results. In 2015, we recorded a non-cash impairment of unproved property costs of $288 million.

If oil and/or natural gas prices decrease, we may be required to take write-downs of the carrying values of our properties, which could result in a material adverse effect on our results of operations and financial condition.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for impairment. Under the successful efforts method of accounting, we review our oil and natural gas properties periodically (at least annually) to determine if impairment of such properties is necessary. Significant undeveloped leasehold costs are assessed for impairment at a lease level or resource play level based on our current exploration plans, while leasehold acquisition costs associated with prospective areas that have limited or no previous exploratory drilling are generally assessed for impairment by major prospect area. Proved oil and natural gas property values are reviewed when circumstances suggest the need for such a review and may occur if actual discoveries in a field are lower than anticipated reserves, reservoirs produce below original estimates or if commodity prices fall to a level that significantly affects anticipated future cash flows on the property. If required, the proved properties are written down to their estimated fair market value based on proved reserves and other market factors.

As of December 31, 2015, our estimated reserves are based on the average first day of the month spot price for the preceding 12-month period of $50.28 per barrel of oil and $2.59 per MMBtu of natural gas, as required by the SEC Regulation S-X, Rule 4-10 as amended, which are above the forward strip price as of December 31, 2015. Given the decline in commodity prices, especially oil, we incurred a non-cash impairment charge of approximately $4.0 billion on our proved property in the fourth quarter of 2015. We may incur additional charges in the future depending on the fair value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. We also incurred an impairment charge of $288 million on our unproved property costs in the fourth quarter of 2015. We could incur significant additional impairment charges of our unproved property should continued low oil prices not justify sufficient capital allocation to the continued development of our unproved properties, among other factors. These impairment charges could have a material adverse effect on our results of operations and financial condition for the periods in which such charges are taken. See Item 8. “Financial Statements and Supplementary Data”, Note 3. Impairment Charges, for a further description of our impairment assessment of our developed and undeveloped leasehold acreage.

Our operations are subject to governmental laws and regulations relating to environmental matters, which may expose us to significant costs and liabilities and could exceed current expectations. In addition, regulations relating to climate change and energy conservation may negatively impact our operations.

Our business is subject to laws and regulations that govern environmental matters. These regulations include compliance obligations for air emissions, water quality, wastewater discharge and solid and hazardous waste disposal, spill

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prevention, control and countermeasures, as well as regulations designed for the protection of threatened or endangered species. In some cases, our operations are subject to federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to state regulations relating to conservation practices and protection of correlative rights. These regulations may negatively impact our operations and limit the quantity of natural gas and oil we produce and sell. We must take into account the cost of complying with such requirements in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities, including gathering, transportation, storage and waste disposal facilities. The regulatory frameworks govern, and often require permits for, the handling of drilling and production materials, water withdrawal, disposal of produced water, drilling and production wastes, operation of air emissions sources, and drilling activities, including those conducted on lands lying within wilderness, wetlands, Federal and Indian lands and other protected areas. Various governmental authorities, including the U.S. Environmental Protection Agency (EPA), the DOI, the BIA and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions, such as installing and maintaining pollution controls and maintaining measures to address personnel and process safety and protection of the environment and animal habitat near our operations. 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. Liabilities, penalties, suspensions, terminations and increased costs resulting from any failure to comply with regulations and requirements of the type described above, or from the enactment of additional similar regulations or requirements in the future or a change in the interpretation or the enforcement of existing regulations or requirements of this type, could have a material adverse effect on our business, results of operations and financial condition.

On December 15, 2009, the EPA published its findings that emissions of carbon dioxide, methane, and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. These findings served as a statutory prerequisite for the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the Clean Air Act. The EPA has adopted two sets of related rules, one of which regulates emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources of emissions such as power plants or industrial facilities. The EPA finalized the motor vehicle rule in April 2010 and it became effective January 2011. The EPA adopted the stationary source rule, also known as the "Tailoring Rule," in May 2010, and it also became effective January 2011, although the U.S. Supreme Court partially invalidated the rule in an opinion issued in June 2014. The Tailoring Rule remains applicable for those facilities considered major sources of six other "criteria" pollutants. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S., including NGLs fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA expanded its existing GHG reporting rule to include onshore and offshore oil and natural gas production and onshore processing, transmission, storage and distribution facilities, which includes certain of our facilities, beginning in 2012 for emissions occurring in 2011. Amendments to the GHG reporting rule, revising certain calculation methods and clarifying certain terms, became final in early 2015. Effective January 1, 2016, the EPA has extended reporting to include emissions from completions and workovers of oil wells using hydraulic fracturing, as well as emissions from gathering and boosting systems. Additionally, the EPA announced in January 2015 that it will initiate rulemaking to encompass further segments of industry in GHG reporting, as well as explore regulatory opportunity to require use of new measurement and monitoring technology. In addition, the EPA has continued to adopt GHG regulations of the oil and gas and other industries, such as the final New Source Performance Standards for new coal-fired and natural gas-fired power plants published October 23, 2015. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility.

In March 2014, the White House announced a Climate Action Plan Strategy to Reduce Methane Emissions, and in support the EPA released five technical white papers focusing on emissions in the oil and gas industry. Subsequently, in January 2015, the White House announced that rulemaking will be initiated by several federal agencies to further reduce emissions of methane and VOCs in the oil and gas sector, including the EPA, the BLM, and the Pipeline and Hazardous Materials Safety Administration (PHMSA). On September 18, 2015, the EPA proposed several regulations, including green completions for hydraulically-fractured oil wells, emissions from pneumatic devices, and fugitive emissions at new or modified sources. The EPA has also proposed new control technique guidelines to reduce ozone precursors from oil and gas sources in ozone nonattainment areas, in addition to already-proposed changes to the National Air Quality Ambient Standards for ozone. On January 22, 2015, the BLM proposed updated standards for venting and flaring, which preclude venting except in narrow circumstances and limit flaring at development oil wells. Similarly on October 13, 2015, the PHMSA proposed oil pipeline safety standards aimed at reducing pipeline leaks. Finally, the White House has proposed funding for the Department of Energy (DOE) aimed at quantifying emissions from natural gas infrastructure and development of leak detection and control technology.

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In December 2015, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The text of the Paris Agreement calls for nations to undertake “ambitious efforts” to “hold the increase in global average temperatures to well below 2 ºC above preindustrial levels and to pursue efforts to limit the temperature increase to 1.5 ºC;” reach global peaking of greenhouse gas emissions as soon as possible; and take action to conserve and enhance sinks and reservoirs of greenhouse gases, among other requirements. If ratified, the Paris Agreement will take effect in 2020. It is possible that the Paris Agreement and subsequent domestic and international regulations will have adverse effects on the market for crude oil, natural gas and other fossil fuel products.

In addition, the U.S. Congress has from time to time considered adopting 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. Although the U.S. Congress has not adopted such legislation at this time, it may do so in the future and many states continue to pursue regulations to reduce greenhouse gas emissions. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances that correspond to their annual emissions of GHGs. The number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. As the number of GHG emission allowances declines each year, the cost or value of such allowances is expected to escalate significantly.

Regulation of GHG emissions could also result in reduced demand for our products, as oil and natural gas consumers seek to reduce their own GHG emissions. Any regulation of GHG emissions, including through a cap-and-trade system, technology mandate, emissions tax, reporting requirement or other program, could have a material adverse effect on our business, results of operations and financial condition. In addition, to the extent climate change results in more severe weather and significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic effects, our own, our counterparties’ or our customers’ operations may be disrupted, which could result in a decrease in our available products or reduce our customers’ demand for our products.

Further, there have been various legislative and regulatory proposals at the federal and state levels to provide incentives and subsidies to (i) shift more power generation to renewable energy sources and (ii) support technological advances to drive less energy consumption. These incentives and subsidies could have a negative impact on oil, natural gas and NGLs consumption.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and health and safety laws and regulations applicable to our business, and new legislation or regulation on safety procedures in exploration and production operations could require us to adopt expensive measures and adversely impact our results of operation.

There is inherent risk in our operations of incurring significant environmental costs and liabilities due to our generation and handling of petroleum hydrocarbons and wastes, because of our air emissions and wastewater discharges, and as a result of historical industry operations and waste disposal practices. Some of our owned and leased properties have been used for oil and natural gas exploration and production activities for a number of years, often by third parties not under our control. During that time, we and/or other owners and operators of these facilities may have generated or disposed of wastes that polluted the soil, surface water or groundwater at our facilities and adjacent properties. For our non-operated properties, we are dependent on the operator for operational and regulatory compliance. We could be subject to claims for personal injury and/or natural resource and property damage (including site clean-up and restoration costs) related to the environmental, health or safety impacts of our oil and natural gas production activities, and we have been from time to time, and currently are, named as a defendant in litigation related to such matters. Under certain laws, we also could be subject to joint and several and/or strict liability for the removal or remediation of contamination regardless of whether such contamination was the result of our activities, even if the operations were in compliance with all applicable laws at the time the contamination occurred and even if we no longer own and/or operate on the properties. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also 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. We have been and continue to be responsible for remediating contamination, including at some of our current and former facilities or areas where we produce hydrocarbons. While to date none of these obligations or claims have involved costs that have materially adversely affected our business, we cannot predict with certainty whether future costs of newly discovered or new contamination might result in a materially adverse impact on our business or operations.

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There have been various regulations proposed and implemented that could materially impact the costs of exploration and production operations and cause substantial delays in the receipt of regulatory approvals from both an environmental and safety perspective. It is possible that more stringent regulations might be enacted or delays in receiving permits may occur in other areas, such as our onshore regions of the United States (including drilling operations on other federal or state lands).

Our operations could result in an equipment malfunction or oil spill that could expose us to significant liability.

Despite the existence of various procedures and plans, there is a risk that we could experience well control problems in our operations. As a result, we could be exposed to regulatory fines and penalties, as well as landowner lawsuits resulting from any spills or leaks that might occur. While we maintain insurance against some of these risks in amounts that we believe are reasonable, our insurance coverages have material deductibles, self-insurance levels and limits on our maximum recovery and do not cover all risks. For example, from time to time we may not carry, or may be unable to obtain on terms that we find acceptable and/or reasonable, insurance coverage for certain exposures including, but not limited to, certain environmental exposures (including potential environmental fines and penalties), business interruption and named windstorm/hurricane exposures and, in limited circumstances, certain political risk exposures. The premiums and deductibles we pay for certain insurance policies are also subject to the risk of substantial increases over time that could negatively impact our financial results. In addition, we may not be able to renew existing insurance policies or procure desirable insurance on commercially reasonable terms. There is also a risk that our insurers may default on their insurance coverage obligations or that amounts for which we are insured, or that the proceeds of such insurance, will not compensate us fully for our losses. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

Although we might also have remedies against our contractors or vendors or our joint working interest owners with regard to any losses associated with unintended spills or leaks, the ability to recover from such parties will depend on the indemnity provisions in our contracts as well as the facts and circumstances associated with the causes of such spills or leaks. As a result, our ability to recover associated costs from insurance coverages or other third parties is uncertain.

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

We use hydraulic fracturing extensively in our operations. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Safe Drinking Water Act (the SDWA) regulates the underground injection of substances through the Underground Injection Control (UIC) program. While hydraulic fracturing generally is exempt from regulation under the UIC program, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program as “Class II” UIC wells. On October 21, 2011, the EPA announced its intention to propose federal Clean Water Act regulations governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the DOI published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The revised proposed rule was subject to an extended 90-day public comment period which ended on August 23, 2013, though a final rule has not been released. In March 2015, the BLM published final rules for hydraulic fracturing on federal and certain tribal lands, including use of tanks for recovered water, updated cementing and testing requirements, and disclosure of chemicals used in hydraulic fracturing. Several states and the Ute Indian Tribe have filed suit to challenge these rules, and on September 30, 2015, a federal court issued a preliminary injunction suspending the rules.

The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. The EPA issued a final draft report on June 4, 2015. A Scientific Advisory Board (SAB) formed to help the EPA review its findings then issued draft comments on January 7, 2016. As part of these studies, both the EPA and the House committee have requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, when final and depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Congress has in recent legislative sessions considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of “underground injection” and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process, were proposed in recent sessions of Congress. The U.S. Congress may consider similar SDWA legislation in the future.

On August 16, 2012, the EPA published final regulations under the Clean Air Act (CAA) that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA promulgated New Source Performance Standards establishing emission limits for sulfur dioxide (SO_2) and volatile organic compounds

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(VOCs). The final rule requires a 95% reduction in VOCs emitted by mandating the use of reduced emission completions or “green completions” on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. Until this date, emissions from fractured and refractured gas wells were to be reduced through reduced emission completions or combustion devices. The rules also establish new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In response to numerous requests for reconsideration of these rules from both industry and the environmental community and court challenges to the final rules, the EPA announced its intention to issue revised rules in 2013. The EPA published revised portions of these rules on September 23, 2013 for VOCs emissions for production oil and gas storage tanks, in part phasing in emissions controls on storage tanks past October 15, 2013. Additional revisions became effective December 31, 2014, primarily defining two stages of well completion operations.

Several states have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, Texas enacted a law requiring oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission adopted rules and regulations applicable to all wells for which the Texas Railroad Commission issues an initial drilling permit on or after February 1, 2012. The regulations require that well operators disclose the list of chemical ingredients subject to the requirements of the Occupational Safety and Health Administration (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Furthermore, on May 23, 2013, the Texas Railroad Commission issued an updated “well integrity rule,” addressing requirements for drilling, casing and cementing wells. The rule also includes new testing and reporting requirements, such as (i) clarifying the due date for cementing reports after well completion or after cessation of drilling, whichever is earlier, and (ii) the imposition of additional testing on “minimum separation wells” less than 1,000 feet below usable groundwater, which are not found in the Eagle Ford Shale or Permian Basin. The “well integrity rule” took effect in January 2014. Similarly, Utah’s Division of Oil, Gas and Mining passed a rule on October 24, 2012 requiring all oil and gas operators to disclose the amount and type of chemicals used in hydraulic fracturing operations using the national registry FracFocus.org. Finally, the federal BLM published rules on March 24, 2015 requiring similar disclosure of hydraulic fracturing fluid used on BLM lands, as well as additional requirements addressing casing and cementing, mechanical integrity testing, water management, monitoring and reporting. BLM’s new rules have been challenged in federal court by several states and Indian Tribes, including Utah and the Ute Indian Tribe, who obtained a nationwide preliminary injunction suspending the rules in June 2015.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have adversely impacted drinking water supplies, use of surface water, and the environment generally. If new laws or regulations that significantly restrict hydraulic fracturing, such as amendments to the SDWA, are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as 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. In addition, if hydraulic fracturing is further regulated at the federal or state level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. Until such regulations are finalized and implemented, it is not possible to estimate their impact on our business. At this time, no adopted regulations have imposed a material impact on our hydraulic fracturing operations.

Any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Tax laws and regulations may change over time, including the elimination of federal income tax deductions currently available with respect to oil and gas exploration and development.

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 at the time that the filings were made. If these laws or regulations change, or if the taxing authorities do not agree with our interpretation of the effects of such laws and regulations, it could have a material adverse effect on our business and financial condition. Legislation has been proposed that would eliminate certain U.S. federal income tax provisions currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;

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- the elimination of current expensing of intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

In addition, the President of the United States recently proposed adding a $10.25 per Bbl tax on crude oil produced in the United States.

It is unclear whether any such changes will be enacted or how soon such changes could be effective. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including the imposition of, or increases in production, severance or similar taxes) could have a material adverse effect on our business, results of operations and financial condition.

We have certain contingent liabilities that could exceed our estimates.

We have certain contingent liabilities associated with litigation, regulatory, environmental and tax matters described in Note 9 to our consolidated financial statements and elsewhere in this Annual Report on Form 10-K. In addition, the positions taken in our federal, state, local and previously in non-U.S. tax returns require significant judgments, use of estimates and interpretation of complex tax laws. Although we believe that we have established appropriate reserves for our litigation, regulatory, environmental and tax matters, we could be required to accrue additional amounts in the future and/or incur more actual cash expenditures than accrued for and these amounts could be material.

Retained liabilities associated with businesses or assets that we have sold could exceed our estimates and we could experience difficulties in managing these liabilities.

We have sold various assets and either retained certain liabilities or indemnified certain purchasers against future liabilities relating to businesses and assets sold, including breaches of warranties, environmental expenditures, asset retirements and other representations that we have provided. We may also be subject to retained liabilities with respect to certain divested assets by operation of law. For example, the recent and sustained decline in commodity prices has created an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging or abandonment obligations that attach to such assets. In that event, due to operation of law, we may be required to assume these plugging or abandonment obligations on assets no longer owned and operated by us. Although we believe that we have established appropriate reserves for any such liabilities, we could be required to accrue additional amounts in the future and these amounts could be material.

Our debt agreements contain restrictions that limit our flexibility in operating our business.

Our existing debt agreements contain, and any other existing or future indebtedness of ours would likely contain, a number of covenants that impose operating and financial restrictions on us, including restrictions on our and our subsidiaries ability to, among other things:

- incur additional debt, guarantee indebtedness or issue certain preferred shares;
- pay dividends on or make distributions in respect of, or repurchase or redeem, our capital stock or make other restricted payments;
- prepay, redeem or repurchase certain debt;
- make loans or certain investments;
- sell certain assets;
- create liens on certain assets;
- consolidate, merge, sell or otherwise dispose of all or substantially all of our assets;
- enter into certain transactions with our affiliates;
- alter the businesses we conduct;
- enter into agreements restricting our subsidiaries’ ability to pay dividends; and
- designate our subsidiaries as unrestricted subsidiaries.

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In addition, the RBL Facility requires us to comply with certain financial covenants. See Note 8 for additional discussion of the RBL covenants.

As a result of these covenants, we may be limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

A failure to comply with the covenants under the RBL Facility or any of our other indebtedness could result in an event of default, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations. In the event of any such default, the lenders thereunder:

- will not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable and terminate all commitments to extend further credit; or
- could require us to apply all of our available cash to repay these borrowings.

Such actions by the lenders could cause cross defaults under our other indebtedness. If we were unable to repay those amounts, the lenders or holders under the RBL Facility and our other secured indebtedness could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our assets as collateral under the RBL Facility and our senior secured term loans.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

A description of our properties is included in Part I, Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interests in these properties or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our material legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 9, and is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Our common stock started trading on the New York Stock Exchange under the symbol EPE on January 17, 2014. As of February 10, 2016, we had 18 stockholders of record which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

Quarterly Stock Prices. The following table reflects the quarterly high and low sales prices for the last two fiscal years for our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange:

	2015		2014	
	High	Low	High	Low
Fourth Quarter	$7.82	$3.48	$16.79	$7.16
Third Quarter	11.56	4.85	22.55	16.98
Second Quarter	15.21	10.78	23.05	18.30
First Quarter	13.36	8.71	19.73	16.82

Stock Performance Graph

The performance graph and the information contained in this section is not "soliciting material", is being "furnished" not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing.

The graph below compares the change in the cumulative total shareholder return assuming the investment of $100 on January 17, 2014 (our first trading day) and the reinvestment of all dividends in each of EP Energy's Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. The historical stock performance shown on the graph below is not indicative of future price performance.

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	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
EP Energy Corporation	$57.96	$70.41	$28.48	$24.23
S&P 500 Index	115.28	115.60	108.16	115.77
Dow Jones U.S. Exploration and Production Index	94.69	91.75	72.72	70.00

	January 17, 2014	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
EP Energy Corporation	$100.00	$108.24	$127.49	$ 96.68	$57.74
S&P 500 Index	100.00	102.27	107.62	108.84	114.20
Dow Jones U.S. Exploration and Production Index	100.00	106.58	121.90	110.28	91.79

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ITEM 6. SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

Set forth below is our selected historical consolidated financial data for the periods and as of the dates indicated. We have derived the selected historical consolidated balance sheet data as of December 31, 2015 and December 31, 2014 and the statements of income data and statements of cash flow data for the years ended December 31, 2015, December 31, 2014 and December 31, 2013, from the audited consolidated financial statements of EP Energy Corporation included in this Report on Form 10-K. We have derived the selected historical consolidated balance sheet data as of December 31, 2013 and 2012, and the statements of income data and statements of cash flow data for the period from February 14 to December 31, 2012 and the period from January 1, 2012 through May 24, 2012 from the consolidated financial statements of EP Energy Corporation, and the selected historical consolidated balance sheet as of December 31, 2011, and the statement of income data and statement of cash flow data for the year ended December 31, 2011 from the consolidated historical predecessor financial statements of EP Energy Corporation, which are also not included in this Report on Form 10-K. All financial statement periods present our Brazil operations as discontinued operations prior to its sale. Financial statement periods after May 24, 2012 (successor periods) also present certain domestic natural gas assets sold as discontinued operations prior to their sale. See Item 8. "Financial Statements and Supplementary Data", Note 2. Acquisitions and Divestitures, for further discussion.

The following selected historical financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition" and "Results of Operations" and Item 8, "Financial Statements and Supplementary Data" included in this Report on Form 10-K.

	Successor				Predecessor	
	Year ended December 31, 2015	Year ended December 31, 2014	Year ended December 31, 2013	February 14 to December 31, 2012	January 1, to May 24, 2012	Year ended December 31, 2011
	(in millions, except per common share amounts)					
Results of Operations						
Operating revenues	$1,908	$3,084	$ 1,576	$ 681	$932	$ 1,756
Impairment and ceiling test charges	4,299	2	2	1	62	6
Operating (loss) income	(3,955)	1,493	383	(72)	338	648
Interest expense	(330)	(318)	(354)	(219)	(14)	(14)
(Loss) income from continuing operations	(3,748)	727	(56)	(306)	187	385
Basic and diluted net income (loss) per common share						
(Loss) income from continuing operations	$(15.37)	$3.00	$ (0.27)	$ (1.46)		
Cash Flow						
Net cash provided by (used in):						
Operating activities	$1,327	$1,186	$ 960	$ 449	$580	$ 1,426
Investing activities	(1,543)	(2,044)	(475)	(7,893)	(628)	(1,237)
Financing activities	220	829	(503)	7,513	110	(238)

	As of December 31,				
	2015	2014	2013	2012	2011
			(in millions)		
Financial Position					
Total assets	$5,833	$10,154	$ 8,257	$ 8,212	$5,103

Long-term debt	4,812	4,533	4,340	4,601	851
Stockholders'/ Member's equity	619	4,348	2,937	2,748	3,100

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Factors Affecting Trends. In May 2012, the Sponsors acquired our predecessor for approximately $7.2 billion with approximately $3.3 billion in equity contributions and the issuance of $4.25 billion of debt. For the years ended December 31, 2015 and 2014, we recorded realized and unrealized gains on financial derivatives of $667 million and $985 million. For the year ended December 31, 2015, we recorded non-cash impairment charges of approximately $4.3 billion on our proved and unproved properties. For the year ended December 31, 2013 and the period from February 14 to December 31, 2012, we recorded realized and unrealized losses on financial derivatives included in operating revenues of $52 million and $62 million, respectively, in addition in the period from February 14 to December 31, 2012, we recorded restructuring costs of $221 million. For the period from January 1 to May 24, 2012, and for the year ended December 31, 2011, we recorded realized and unrealized gains on financial derivatives included in operating revenues of $365 million and $284 million, and non-cash ceiling test and other impairment charges of $62 million and $6 million, respectively.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the financial statements and the accompanying notes presented in Item 8 of this Annual Report on Form 10-K. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in "Risk Factors". Actual results may differ materially from those contained in any forward-looking statements. See "Cautionary Statement Regarding Forward-Looking Statements" in the front of this report. The periods ended December 31, 2014 and 2013 included in these financial statements present our Brazilian operations and certain domestic natural gas assets sold, including the South Louisiana Wilcox, CBM, South Texas and Arklatex assets as discontinued operations. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our", "us" and "the Company" refer to EP Energy Corporation (prior to the Corporate Reorganization described in Note 1 to our consolidated financial statements all such references were to EPE Acquisition, LLC) and its predecessor entities and each of their consolidated subsidiaries.

Our Business

Overview. We are an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. We are focused on creating shareholder value through the development of our low-risk drilling inventory located in four areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), the Altamont Field in the Uinta Basin (Northeastern Utah) and the Haynesville Shale (North Louisiana), which are further described in Item I, Business.

We evaluate growth opportunities for our asset portfolio that are aligned with our core competencies and that are in areas that we believe can provide us a competitive advantage. Strategic acquisitions of leasehold acreage or acquisitions of producing assets can provide opportunities to achieve our long-term goals by leveraging existing expertise in each of our four areas, balancing our exposure to regions, basins and commodities, helping us to achieve risk-adjusted returns competitive with those available within our existing drilling programs and by increasing our reserves. We continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term goals.

During 2015, we acquired approximately 12,000 net acres adjacent to our Eagle Ford Shale acreage for an adjusted cash purchase price of approximately $111 million. The acquisition added an average of 483 Bbls/d of oil and 660 Boe/d to our 2015 annual production. As of December 31, 2015, we estimate this acquisition added 197 drilling locations.

Factors Influencing Our Profitability. Our profitability is dependent on the prices we receive for our oil and natural gas, the costs to explore, develop, and produce our oil and natural gas, and the volumes we are able to produce, among other factors. Our long-term profitability will be influenced primarily by:

- maintaining and growing our proved reserve base and production volumes through the successful execution of our drilling programs or through acquisitions;
- finding and producing oil and natural gas at reasonable costs;
- managing cash costs; and
- managing commodity price risks on our oil and natural gas production.

In addition to these factors, our future profitability and performance will be affected by volatility in the financial and commodity markets, changes in the cost of drilling and oilfield services, operating and capital costs, and our debt level and related interest costs. Additionally, we may be impacted by weather events, regulatory issues or other third party actions outside of our control.

Forward commodity prices play a significant role in determining the recoverability of proved or unproved property costs on our balance sheet. Oil and natural gas prices are inherently volatile and during the latter part of 2014 and throughout 2015 decreased significantly. As a result of the significant decline in forward prices in the fourth quarter, we recorded a non-cash impairment charge of our oil and natural gas properties of approximately $4.3 billion. The charge consisted of both proved and unproved property impairments in our Eagle Ford and Wolfcamp areas. Since the end of 2015, further price declines have occurred. These declines, along with changes to our future capital, production rates, levels of proved reserves and development plans as a consequence of this lower price environment may result in an additional impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be significant. For a further discussion of the impairment of our proved and unproved property costs, see Part II, Item 8, Financial Statements and Supplementary Data, Note 3 and Critical Accounting Estimates for key assumptions and judgments used in these estimations.

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We attempt to mitigate certain of our risks through actions such as entering into longer term contractual arrangements to control costs and by entering into derivative contracts to stabilize cash flows and reduce the financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our derivative contracts, our reported results of operations and financial position can be impacted significantly by commodity price movements from period to period. Adjustments to our strategy and the decision to enter into new positions or to alter existing positions are made based on the goals of the overall company.

Derivative Instruments. Our realized prices from the sale of our oil and natural gas are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our oil and natural gas, and (ii) other contractual pricing adjustments contained in our underlying sales contracts. In order to stabilize cash flows and protect the economic assumptions associated with our capital investment programs, we have entered into financial derivative contracts to reduce the financial impact of unfavorable commodity price movements and locational price differences. Certain derivative contracts involve the receipt or payment of premiums. During 2015, we did not receive or pay any premiums on such derivative contracts. During 2015, we (i) settled commodity index hedges on approximately 95% of our oil production, 80% of our total liquids production and 82% of our natural gas production at average floor prices of $91.19 per barrel of oil and $4.26 per MMBtu, respectively and (ii) hedged basis risk on approximately 68% of our 2015 Eagle Ford oil production and a portion of our Wolfcamp production. To the extent our oil and natural gas production is unhedged, either from a commodity index price or locational price perspective, our financial results will be impacted from period to period as further described in Operating Revenues. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of December 31, 2015.

	2016		2017	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil				
Fixed Price Swaps				
WTI	8,510	$80.03	4,015	$66.11
LLS	9,516	$80.51	—	$—
Three Way Collars				
Ceiling - WTI	—	$—	1,095	$75.13
Floors - WTI(2)	—	$—	1,095	$65.00
Basis Swaps				
LLS vs. WTI(3)	2,013	$3.91	—	$—
LLS vs. Brent(4)	2,196	$(4.99)	3,650	$(3.14)
Midland vs. Cushing(5)	732	$(0.83)	1,460	$(0.68)
WTI - CM vs. TM(6)	11,712	$0.31	—	$—
NYMEX Roll(7)	8,230	$(0.86)	—	$—
Natural Gas				
Fixed Price Swaps	7	$4.20	—	$—
Propane				
Fixed Price Swaps	15	$0.55	—	$—

(1) Volumes presented are MBbls for oil, TBtu for natural gas and MMGal for propane. Prices presented are per Bbl of oil, MMBtu of natural gas and Gal for propane.
(2) If market prices settle at or below $55.00 in 2017, we will receive a “locked-in” cash settlement of the market price plus $10.00 per Bbl.
(3) EP Energy receives WTI plus the basis spread listed and pays LLS.
(4) EP Energy receives Brent plus the basis spread listed and pays LLS.
(5) EP Energy receives Cushing plus the basis spread listed and pays Midland.
(6) EP Energy receives WTI trade month (TM) plus the spread listed and pays WTI calendar month (CM).

(7) These positions hedge the timing risk associated with our physical sales. We generally sell oil for the delivery month at a sales price based on the average NYMEX WTI price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").

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Summary of Liquidity and Capital Resources. As of December 31, 2015, we had available liquidity, including existing cash, of approximately $1.62 billion. We believe we have sufficient liquidity for 2016 from our cash flows from operations including our hedging program (which provides significant price protection to our near-term revenues and cash flows), combined with the availability under our $2.75 billion RBL Facility and available cash, to fund our current obligations, projected working capital requirements and capital spending plans. In 2015, we extended our $2.75 billion RBL Facility maturity date from May 2017 to May 2019, provided that our remaining 2018 and 2019 secured term loans are retired or refinanced at least six months prior to their maturity. Several factors could impact our liquidity which are further described in "Liquidity and Capital Resources".

Outlook. For 2016, we expect the following:

- Capital expenditures of approximately $500 million to $900 million.
- Average daily production volumes for the year of approximately 91 MBoe/d to 97 MBoe/d, including average daily oil production volumes of approximately 45 MBbls/d to 50 MBbls/d.
- Per unit adjusted cash operating costs for the year of approximately $9.50 to $10.50 per Boe, and transportation costs of $3.40 to $3.65 per Boe.

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Production Volumes and Drilling Summary

Production Volumes. Below is an analysis of our production volumes for the years ended December 31:

	2015	2014	2013
United States (MBoe/d)			
Eagle Ford Shale	58.2	50.9	36.6
Wolfcamp Shale	19.9	15.3	5.5
Altamont	17.1	15.5	11.9
Haynesville Shale	14.4	15.9	27.1
Other	0.1	0.1	0.1
Divested assets(1)	—	—	6.0
Total	109.7	97.7	87.2
Oil (MBbls/d)			
Consolidated volumes	60.5	54.8	36.2
Divested assets(1)	—	—	0.5
Total Combined	60.5	54.8	36.7
Natural Gas (MMcf/d)			
Consolidated volumes	207	190	230
Divested assets(1)	—	—	28
Total Combined	207	190	258
NGLs (MBbls/d)			
Consolidated volumes	14.7	11.3	6.7
Divested assets(1)	—	—	0.9
Total Combined	14.7	11.3	7.6

(1) Represents production volumes from Four Star Oil & Gas Company (Four Star), our equity investment sold in September 2013.

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes and oil production increased 7.3 MBoe/d (approximately 14%) and 4.2 MBbls/d (12%), respectively, for the year ended December 31, 2015 compared to 2014 due to the success of our drilling program in the area. During 2015, we completed 118 additional operated wells in the Eagle Ford, and we had a total of 563 net operated wells as of December 31, 2015 (which includes wells acquired in September 2015). A majority of our acreage is located in the core of the oil window, primarily in LaSalle County.
- Wolfcamp Shale—Our Wolfcamp Shale equivalent volumes increased 4.6 MBoe/d (approximately 30%) for the year ended December 31, 2015 compared to 2014 as we continued to progress the development of the program. During 2015, we completed 36 additional operated wells, for a total of 237 net operated wells as of December 31, 2015.
- Altamont—Our Altamont equivalent volumes increased 1.6 MBoe/d (approximately 10%) for the year ended December 31, 2015 compared to 2014. Altamont produced an average of 12.4 MBbls/d of oil during 2015, and we completed an additional 30 operated oil wells for a total of 378 net operated wells at December 31, 2015.
- Haynesville Shale—Our Haynesville Shale equivalent volumes decreased 1.5 MMcf/d (approximately 9%) for the year ended December 31, 2015 compared to 2014, due to natural production declines. In 2015, we began testing the impact of current completion and refracking techniques on well performance and financial returns. As of December 31, 2015, we had completed 4 additional operated wells for a total of 103 net operated wells in the Haynesville Shale, and our total natural gas production for 2015 was approximately 87 MMcf/d.

Future volumes will be impacted by our levels of capital spending and the timing of that spending. In the current commodity price environment, we could see this level of spending decrease which may result in lower reported volumes in the future.

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Reserve Replacement Ratio/Reserve Replacement Costs

We calculate two primary non-GAAP metrics associated with reserves performance: (i) a reserve replacement ratio and (ii) reserve replacement costs, to measure our ability to establish a trend of adding reserves at a reasonable cost in our drilling programs. The reserve replacement ratio is an indicator of our ability to replenish annual production volumes and grow our reserves. It is important for us to economically find and develop new reserves that will more than offset produced volumes and provide for future production given the inherent decline of hydrocarbon reserves. In addition, we calculate reserve replacement costs to assess the cost of adding reserves, which is ultimately included in depreciation, depletion and amortization expense. We believe the ability to develop a competitive advantage over other oil and natural gas companies is dependent on adding reserves at lower costs than our competition. We calculate these metrics as follows:

Reserve replacement ratio	Sum of reserve additions(1) Actual production for the corresponding period
Reserve replacement costs/Boe	Total oil and natural gas capital costs(2) Sum of reserve additions(1)

(1) Reserve additions include proved reserves and reflect reserve revisions for prices and performance, extensions, discoveries and other additions and acquisitions and do not include unproved reserve quantities. We present these metrics separately, both including and excluding the impact of price revisions on reserves, to demonstrate the effectiveness of our drilling program exclusive of economic factors (such as price) outside of our control. All amounts are derived directly from the table presented in "Financial Statements and Supplementary Data—Supplemental Oil and Natural Gas Operations."

(2) Total oil and natural gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations. Amounts are derived directly from the table presented in "Financial Statements and Supplementary Data—Supplemental Oil and Natural Gas Operations". We do not include estimated future capital costs for the development of proved undeveloped reserves in our calculation of reserve replacement costs. See "Business—Oil and Natural Gas Properties—Oil, Natural Gas and NGLs Reserves and Production—Proved Undeveloped Reserves (PUDs)" for the estimated amounts in our December 31, 2015 internal reserve report to be spent in 2016, 2017 and 2018 to develop our proved undeveloped reserves.

The reserve replacement ratio and reserve replacement costs per unit are statistical indicators that have limitations, including their predictive and comparative value. As an annual measure, the reserve replacement ratio is limited because it typically varies widely based on the extent and timing of new discoveries, project sanctioning and property acquisitions. In addition, since the reserve replacement ratio does not consider the cost or timing of developing future production of new reserves, it cannot be used as a measure of value creation.

The exploration for and the acquisition and development of oil and natural gas reserves is inherently uncertain as further discussed in "Risk Factors—Risks Related to Our Business and Industry." One of these risks and uncertainties is our ability to spend sufficient capital to increase our reserves. While we currently expect to spend such amounts in the future, there are no assurances as to the timing and magnitude of these expenditures or the classification of the proved reserves as developed or undeveloped. At December 31, 2015, proved developed reserves represented approximately 47% of our total proved reserves. Proved developed reserves will generally begin producing within the year they are added, whereas proved undeveloped reserves generally require additional future expenditures.

The table below shows our reserve replacement ratio and reserve replacement costs, including and excluding the effect of price revisions on reserves and excluding acquisitions, for our operations for each of the years ended December 31:

	Including Price Revisions(1)			Excluding Price Revisions(1)		
	2015	2014	2013	2015	2014	2013
Reserve Replacement Ratios(2)(3)	(117)%	343%	476%	(48)%	254%	464%
Proved Developed Reserves(4)	47%	38%	33%	47%	38%	33%
Proved Undeveloped Reserves(4)	53%	62%	67%	53%	62%	67%
	$(25.78)	$16.93	$12.62	$(62.52)	$22.85	$12.95

Reserve Replacement Costs[(2)(3)(5)]($/Boe)

(1) Final reported proved undeveloped reserves generated positive undiscounted cash flow in each respective report year.

(2) For the year ended December 31, 2015, reserve replacement ratio and reserve replacement costs including acquisitions and price revisions were (90)% and $(36.42) per Boe, and excluding price revisions were (22)% and $(151.77) per Boe. For the year ended December 31, 2014, reserve replacement ratio and reserve replacement costs including acquisitions and price revisions were 363% and $16.90 per Boe, and excluding price revisions were 274% and $22.37 per Boe. No acquisitions are included in our reserve replacement ratio or reserve replacement costs for the year ended December 31, 2013, as any such amounts are immaterial to the amounts presented.

(3) For the year ended December 31, 2015, reserve replacement ratio and reserve replacement costs were negative due to the impact of the SEC's five-year development rule after reductions in estimated capital in our long-range development plan based on the lower price environment which resulted in negative PUD revisions of 85 MMBoe. The year ended December 31, 2014, includes negative PUD revisions of 2 MMBoe due to long-range development plan reductions resulting from changes in economic outlook.

(4) Represents our net proved reserve percentage by classification based on our internal reserve reports.

(5) Proved and unproved leasehold costs are included in all calculations.

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Listed below is a supplemental calculation of our reserve replacement ratio and reserve replacement costs, excluding the effect of price revisions and the changes in our long-range development plan on reserves and excluding acquisitions, for our operations for each of the years ended December 31:

	2015		2014		2013	
Reserve Replacement Ratios[(1)]	164	%	254	%	464	%
Reserve Replacement Costs[(1)(2)]($/Boe)	$18.32		$22.85		$12.95	

(1) For the year ended December 31, 2015, reserve replacement ratio and reserve replacement costs including acquisitions were 191% and $17.23 per Boe. For the year ended December 31, 2014, reserve replacement ratio and reserve replacement costs including acquisitions were 274% and $22.37 per Boe. No acquisitions are included in our reserve replacement ratio or reserve replacement costs for the year ended December 31, 2013, as any such amounts are immaterial to the amounts presented.

(2) Proved and unproved leasehold costs are included in all calculations.

We typically cite reserve replacement costs in the context of a multi-year trend, in recognition of its limitation as a single year measure, and also to demonstrate consistency and stability, which are essential to our business model. The table below shows our reserve replacement costs for our operations for the three years ended December 31, 2015.

	Including Price Revisions ($/Boe)	Excluding Price Revisions
Reserve Replacement Costs		0
Excluding acquisitions	$22.90	$23.74
Including acquisitions	$22.17	$22.93

Our reserve replacement costs for our operations for the three years ended December 31, 2015, excluding the effect of the changes in our long-range development plan on reserves, were $17.08 per Boe (excluding acquisitions) and $16.85 per Boe (including acquisitions), respectively.

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Results of Operations

The information below reflects financial results for EP Energy Corporation for the years ended December 31, 2015, 2014 and 2013. Our financial results for the years ended December 31, 2014 and 2013 reflect the presentation of certain domestic natural gas assets divested and the sale of our Brazilian operations as discontinued operations.

The information in the table below provides summary GAAP financial results by each of the periods presented.

	Year ended December 31,		
	2015	2014	2013
		(in millions)	
Operating revenues:			
Oil	$981	$1,705	$1,254
Natural gas	200	284	300
NGLs	60	110	74
Total physical sales	1,241	2,099	1,628
Financial derivatives	667	985	(52)
Total operating revenues	1,908	3,084	1,576
Operating expenses:			
Oil and natural gas purchases	31	23	25
Transportation costs	116	100	85
Lease operating expenses	186	193	147
General and administrative	148	244	229
Depreciation, depletion and amortization	983	875	585
Impairment charges	4,299	2	2
Exploration and other expense	20	25	41
Taxes, other than income taxes	80	129	79
Total operating expenses	5,863	1,591	1,193
Operating (loss) income	(3,955)	1,493	383
Other income (expense)	—	1	(12)
Loss on extinguishment of debt	(41)	(17)	(9)
Interest expense	(330)	(318)	(354)
(Loss) income from continuing operations before income taxes	(4,326)	1,159	8
Income tax (benefit) expense	(578)	432	64
(Loss) income from continuing operations	(3,748)	727	(56)
Income from discontinued operations, net of tax	—	4	506
Net (loss) income	$(3,748)	$731	$450

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the years ended December 31, 2015, 2014 and 2013. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

	Year ended December 31,		
	2015	2014	2013
		(in millions)	
Operating revenues:			
Oil	$981	$1,705	$1,254
Natural gas	200	284	300
NGLs	60	110	74
Total physical sales	1,241	2,099	1,628
Financial derivatives	667	985	(52)
Total operating revenues	$1,908	$3,084	$1,576
Volumes:			
Oil (MBbls)(1)	22,078	19,985	13,432
Natural gas (MMcf)(1)	75,533	69,434	93,866
NGLs (MBbls)(1)	5,366	4,116	2,761
Equivalent volumes (MBoe)(1)	40,033	35,673	31,837
Total MBoe/d(1)	109.7	97.7	87.2
Consolidated prices per unit(2):			
Oil			
Average realized price on physical sales ($/Bbl)(3)	$44.28	$85.31	$94.75
Average realized price, including financial derivatives ($/Bbl)(3)(4)	$82.18	$88.77	$97.56
Natural gas			
Average realized price on physical sales ($/Mcf)(3)	$2.27	$3.76	$3.28
Average realized price, including financial derivatives ($/Mcf)(3)(4)	$3.59	$3.34	$2.97
NGLs			
Average realized price on physical sales ($/Bbl)	$11.22	$26.73	$30.58
Average realized price, including financial derivatives ($/Bbl)(4)	$12.36	$27.78	$—

(1) In September 2013, we sold our equity investment in Four Star. For the year ended December 31, 2013, Four Star's production volumes were 197 MBbls of oil; 10,050 MMcf of natural gas; 327 MBbls of NGLs; and 2,199 MBoe (6 MBoe/d) of equivalent volumes.

(2) Oil prices for the year ended December 31, 2015 are calculated including a reduction of $3 million for oil purchases associated with managing our physical sales. Natural gas prices for the years ended December 31, 2015, 2014 and 2013 are calculated including a reduction of $28 million, $23 million and $25 million, respectively, for natural gas purchases associated with managing our physical sales. Prices per unit are based on consolidated volumes and do not include volumes associated with Four Star which was sold in September 2013.

(3) Changes in realized oil and natural gas prices reflect the effects of unfavorable unhedged locational or basis differentials, unhedged volumes and contractual deductions between the commodity price index and the actual price at which we sold our oil and natural gas.

(4) The years ended December 31, 2015, 2014 and 2013 include approximately $837 million, $69 million and $29 million, respectively, of cash receipts for the settlement of crude oil derivative contracts. The years ended December 31, 2015, 2014 and 2013 include approximately $99 million of cash received, $30 million of cash paid and $28 million of cash paid for the settlement of natural gas financial derivatives. For the years ended December 31, 2015 and 2014, we received approximately $6 million and $4 million, respectively, for the

settlement of NGLs derivative contracts. No cash premiums were received or paid for the year ended December 31, 2015. Cash premiums received for the years ended December 31, 2014 and 2013, were approximately $1 million and $9 million, respectively.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the year ended December 31, 2015, physical sales decreased by $858 million (41%), compared to the year ended December 31, 2014. For the year ended December 31, 2014, physical sales increased by $471 million (29%) compared to the year ended December 31, 2013. Physical sales have decreased primarily due to lower commodity prices partially offset by oil and natural gas volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. The table below displays the price and volume variances on our physical sales when comparing the years ended December 31, 2015 and 2014.

	Oil	Natural gas	NGLs	Total
	(in millions)			
December 31, 2014 sales	$1,705	$284	$110	$2,099
Change due to prices	(903)	(109)	(83)	(1,095)
Change due to volumes	179	25	33	237
December 31, 2015 sales	$981	$200	$60	$1,241

Oil sales for the year ended December 31, 2015, compared to the year ended December 31, 2014, decreased by $724 million (42%), due primarily to lower oil prices partially offset by oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. In 2015, Eagle Ford oil production volumes increased by 12% (4 MBbls/d) compared with the year ended December 31, 2014. In addition, Wolfcamp oil production volumes increased by 7% (1 MBbls/d). For the year ended December 31, 2014, oil sales increased by $451 million compared to the year ended December 31, 2013 attributable mainly to a 45% increase (11 MBbls/d) in consolidated oil volumes in our Eagle Ford area.

Natural gas sales decreased for the year ended December 31, 2015 compared with the year ended December 31, 2014, primarily due to lower natural gas prices and a decrease in volumes due to natural gas production declines in the Haynesville Shale, offset by natural gas volume growth in Wolfcamp, Eagle Ford and Altamont. Natural gas sales decreased for the year ended December 31, 2014 compared with the year ended December 31, 2013 due to the decrease in volumes in Haynesville as a result of suspending the drilling program in 2012 and only resuming capital activity in 2015, partially offset by higher natural gas prices.

Our oil and natural gas is typically sold at index prices (WTI, LLS and Henry Hub) or posted prices at various delivery points across our producing basins. Realized prices received (not considering the effects of hedges) are generally less than the stated index price as a result of contractual deducts, differentials from the index to the delivery point and/or discounts for quality or grade. Generally as the index price of our commodities increase, deducts and differentials widen and can further widen for temporary or permanent changes in supply or demand, capacity constraints or the build out of infrastructure in developing areas.

In the Eagle Ford, our oil is sold at prices tied to benchmark LLS crude oil. In Wolfcamp, physical barrels are generally sold at the WTI Midland Index, which trades at a spread to WTI Cushing. In Altamont, market pricing of our oil is based upon both Salt Lake City refinery postings and rail economics, which reflect transportation and handling costs associated with moving wax crude by truck and/or rail to end users. Across all regions, natural gas realized pricing is influenced by factors such as excess royalties paid on flared gas and the percentage of proceeds retained under processing contracts, in addition to the normal seasonal supply and demand influences and those factors discussed above. The table below displays the weighted average differentials and deducts on our oil and natural gas sales on an average NYMEX price.

	Years ended December 31,			
	2015		2014	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(4.91)	$(0.40)	$(7.69)	$(0.60)
NYMEX	$48.80	$2.67	$92.99	$4.41

The smaller oil differentials and deducts for the year ended December 31, 2015 were primarily a result of an increase in LLS and Midland/Cushing relative to NYMEX in Eagle Ford and Wolfcamp, respectively, improved physical sales contract pricing in both Eagle Ford and Wolfcamp as a result of new contracts, and improved refinery postings in

Altamont. The smaller natural gas differentials and deducts in the year ended December 31, 2015 were primarily a result of improved locational basis differentials in the Haynesville area and lower royalties paid on flared gas.
NGLs sales decreased for the year ended December 31, 2015 compared with the year ended December 31, 2014 and increased for the year ended December 31, 2014 compared to the year ended December 31, 2013. Average realized prices decreased in 2015 compared to the previous years, due in part to lower pricing on all liquids components. NGLs pricing is largely tied to crude oil prices. NGLs volume increased primarily as a result of our Eagle Ford and Wolfcamp drilling programs.

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As of December 31, 2015, the NYMEX spot price of a barrel of oil was $37.04 versus the NYMEX spot price of natural gas of $2.34, or a ratio of 16 to 1. Despite declines in oil prices, the value difference between these commodities is such that we will continue to allocate capital to our oil-based programs. Our overall oil sales (including the impact of financial derivatives) will largely be impacted by commodity pricing, our ability to maintain or grow oil volumes and by the location of our production and the nature of our sales contracts. Based on our hedges in place as of December 31, 2015, we have over 18 MMBbls hedged for 2016 at a weighted average price of $80.29 per barrel. For additional details on our 2016 production guidance and hedge program, refer to Our Business above.

Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the year ended December 31, 2015, we recorded $667 million of derivative gains compared to derivative gains of $985 million during the year ended December 31, 2014. Realized and unrealized losses for the year ended December 31, 2013 were $52 million of derivative losses.

Operating Expenses

Transportation costs. Transportation costs for the years ended December 31, 2015, 2014 and 2013 were $116 million, $100 million and $85 million, respectively. Total transportation costs increased in 2015 compared to 2014 primarily due to gas transportation costs associated with Eagle Ford and Wolfcamp as a result of our production growth and new contracts in these areas, partially offset by a decrease in NGLs transportation costs in Eagle Ford. Transportation costs increases in 2014 compared to 2013 also reflect production growth and new contracts in Eagle Ford and Wolfcamp.

Lease operating expense. Lease operating expense for the years ended December 31, 2015, 2014 and 2013 were $186 million, $193 million and $147 million, respectively. For the year ended December 31, 2015, we experienced an overall decrease of $7 million in lease operating expense from December 31, 2014. On a per equivalent unit basis, however, that decline was 14% from $5.40 per Boe in 2014 to $4.64 per Boe in 2015. As an overall industry, we experienced lower service costs and actively worked to reduce costs given the low commodity price environment. Given ongoing low prices, we anticipate costs to remain lower. In our individual asset programs in 2015, we experienced an approximately $7 million decline in Altamont due to lower maintenance and repair costs, lower chemical costs and lower power and fuel costs. In Eagle Ford, we incurred a decrease of $3 million in 2015 as a result of lower power costs due to releasing rental generators, lower chemical costs due to changing the method in which we treated our gas (amine unit vs. chemicals) and lower disposal and labor costs. These decreases were partly offset by an increase in Wolfcamp of approximately $3 million for the year ended December 31, 2015 due to higher maintenance and repair and compression costs associated with growing production volumes in this area. Total lease operating expense increased in 2014 compared to 2013 due to higher chemical, maintenance, disposal, repair and power costs in Eagle Ford, higher chemical, disposal and compression costs in Wolfcamp and higher chemical, disposal and power costs in Altamont associated with growing production volumes in these areas.

General and administrative expenses. General and administrative expense for the years ended December 31, 2015, 2014 and 2013 was $148 million, $244 million and $229 million, respectively. In 2014, we paid Sponsor-related fees of approximately $90 million under agreements that terminated with the completion of our 2014 initial public offering. Additionally, for the year ended December 31, 2015 we incurred lower payroll, benefits and administrative costs of $20 million compared to the same periods in 2014 from lower headcount as a result of reductions in response to the lower price environment. Partially offsetting these reductions in 2015 were an $11 million insurance settlement received in 2014 and higher transition and restructuring costs of $6 million in 2015.

General and administrative expenses for the year ended December 31, 2014 increased $15 million compared to the year ended December 31, 2013. The year ended December 31, 2014, reflects lower payroll, benefits and administrative costs of $39 million compared to the year ended December 31, 2013, an $11 million reduction in general and administrative expenses associated with an insurance settlement and advisory fees paid in January 2014 to our Sponsors of $6.25 million compared to $26 million paid in 2013. However, the higher overall 2014 expense was a result of a transaction fee of $83 million paid to our Sponsors in January 2014 under the amended and restated Management Fee Agreement, which terminated with the completion of our initial public offering in January 2014.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the years ended December 31, 2015, 2014 and 2013 were $983 million, $875 million and $585 million, respectively. Our depreciation, depletion and amortization costs have increased over the three year period due to increases in production volumes from the ongoing development of higher cost oil programs (e.g. Eagle Ford and Wolfcamp) and slightly higher depletion rates. Our average depreciation, depletion and amortization costs per unit for the year-to-date periods were:

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	Year ended December 31,		
	2015	2014	2013
Depreciation, depletion and amortization ($/Boe)	$24.54	$24.53	$19.74

Impairment charges. During the fourth quarter of 2015, we recorded non-cash impairment charges of approximately $4.0 billion on our proved properties in the Eagle Ford Shale and $288 million on our unproved properties in the Wolfcamp Shale. During the fourth quarter, prices across the forward curve declined significantly from the levels at September 30, 2015. See Critical Accounting Estimates for a further discussion.

Exploration and other expense. Exploration and other expense for the years ended December 31, 2015, 2014 and 2013 were $20 million, $25 million and $41 million, respectively. Included in exploration expense for the years ended December 31, 2015, 2014 and 2013 were $9 million, $18 million and $36 million of amortization of unproved leasehold costs. In addition, in 2015 and 2014, we recorded approximately $2 million and $3 million, respectively, as other expense in conjunction with the early termination of contracts for drilling rigs, released in response to the lower price environment.

Taxes, other than income taxes. Taxes, other than income taxes for the years ended December 31, 2015, 2014 and 2013 were $80 million, $129 million and $79 million, respectively. Production taxes decreased for the year ended December 31, 2015 compared to December 31, 2014 due to the significant impact on severance taxes of lower commodity prices. Production taxes increased for the year ended December 31, 2014 compared to December 31, 2013 due to higher severance taxes associated with the growth in production volumes in our oil producing areas. Additionally, production taxes in 2013 reflect a reduction in sales and use tax of $13 million recorded in the second quarter of 2013 associated with settling a Texas sales and use tax audit.

Cash Operating Costs and Adjusted Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas. Cash operating costs is a non-GAAP measure calculated on a per Boe basis and includes total operating expenses less depreciation, depletion and amortization expense, transportation costs, exploration expense, oil and natural gas purchases, impairment charges and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition, restructuring and other non-recurring costs, management and other fees paid to the Sponsors (which terminated on January 23, 2014), the non-cash portion of compensation expense (which represents compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans) and costs associated with our initial public offering. We believe cash operating costs and adjusted cash operating costs per unit are valuable measures of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses for the year-to-date periods below:

	Year ended December 31,					
	2015		2014		2013	
	Total	Per Unit[1]	Total	Per Unit[1]	Total	Per Unit[1]
	(in millions, except per unit costs)					
Total continuing operating expenses	$5,863	$146.44	$1,591	$44.59	$1,193	$40.26
Depreciation, depletion and amortization	(983)	(24.54)	(875)	(24.53)	(585)	(19.74)
Transportation costs	(116)	(2.88)	(100)	(2.81)	(85)	(2.85)
Exploration expense	(18)	(0.44)	(22)	(0.62)	(41)	(1.39)
Oil and natural gas purchases	(31)	(0.79)	(23)	(0.64)	(25)	(0.85)
Impairment charges	(4,299)	(107.38)	(2)	(0.05)	(2)	(0.06)
Total continuing cash operating costs	416	10.41	569	15.94	455	15.37
Transition/restructuring costs, non-cash portion of compensation expense and other[2]	(21)	(0.52)	(95)	(2.67)	(65)	(2.19)
Total adjusted cash operating costs and adjusted per-unit cash costs[3]	$395	$9.89	$474	$13.27	$390	$13.18
Total equivalent volumes (MBoe)[3]	40,033		35,673		29,638	

(1) Per unit costs are based on actual total amounts rather than the rounded totals presented.

(2) For the year ended December 31, 2015, amount includes approximately $8 million of transition and severance costs related to restructuring and $13 million of non-cash compensation expense, adjusted for cash payments made on long-term incentive plans of approximately $8 million. For the year ended December 31, 2014, amount includes $90 million of transaction, management and other fees paid to our Sponsors, $11 million of cash received from an insurance settlement, $5 million of acquisition costs, $9 million of non-cash compensation expense and $2 million of transition and severance costs related to restructuring. For the year ended December 31, 2013, amount includes $7 million of transition and severance costs associated with asset divestitures, management and other fees paid to our Sponsors of $26 million, $31 million of non-cash compensation expense and $1 million of costs associated with our initial public offering. The non-cash portion of compensation expense represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans.

(3) Excludes volumes associated with our equity investment in Four Star sold in September 2013.

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The table below displays the average cash operating costs and adjusted cash operating costs per equivalent unit:

	Year ended December 31,		
	2015	2014	2013
Average cash operating costs ($/Boe)			
Lease operating expenses	$4.64	$5.40	$4.98
Production taxes[1]	1.83	3.39	2.84
General and administrative expenses[2]	3.71	6.83	7.73
Taxes, other than production and income taxes[3]	0.17	0.23	(0.18)
Other expense[4]	0.06	0.09	—
Total continuing cash operating costs	10.41	15.94	15.37
Transition/restructuring costs, non-cash portion of compensation expense and other[2]	(0.52)	(2.67)	(2.19)
Total adjusted cash operating costs	$9.89	$13.27	$13.18

(1) Production taxes include ad valorem and severance taxes which decreased in 2015 due primarily to lower commodity prices and increased in 2014 primarily due to higher severance taxes associated with our higher oil production.

(2) For additional detail of adjusted items included in general and administrative expenses, refer to the reconciliation of cash operating costs and adjusted cash operating costs above.

(3) The year ended December 31, 2013 includes a reduction in sales and use taxes of $13 million associated with settling a sales and use tax matter.

(4) Includes early rig termination fees of $2 million and $3 million incurred during the years ended December 31, 2015 and 2014, respectively.

Other Income Statement Items.

Other income (expense). For the year ended December 31, 2013, we recorded losses on our equity investment as a result of an impairment recorded upon our decision to sell our investment in Four Star. The impairment of $20 million was based on comparison of $183 million in net proceeds received for the sale of Four Star in September 2013 to the underlying carrying value of the investment.

Loss on extinguishment of debt. For the year ended December 31, 2015, we recorded a $41 million loss ($12 million of which was non-cash) on extinguishment of debt in conjunction with the early repayment and retirement of our $750 million senior secured notes due 2019. For the year ended December 31, 2014, we recorded a $17 million in loss on extinguishment of debt for the portion of deferred financing costs written off in conjunction with the repayment and retirement of a PIK toggle note. In 2013, we recorded a $9 million loss on extinguishment of debt associated with the pro-rata portion of deferred financing costs written off in conjunction with the repayment of a portion of our senior secured term loans, a re-pricing of a term loan and the semi-annual redeterminations of our RBL Facility.

Interest expense. Interest expense for the year ended December 31, 2015 compared to 2014 increased due primarily to higher interest expense related to our RBL Facility. The increase in interest expense was partially offset by a decrease due to the retirement of a PIK toggle note in early 2014 and lower amortization of debt issuance costs. Interest expense for the year ended December 31, 2014 compared to 2013 decreased due to the retirement of the PIK toggle note during January 2014 and the repayment of approximately $500 million under our term loans in August 2013.

Income taxes. For the year ended December 31, 2015, our effective tax rate was 13.4%, lower than the statutory rate of 35% as a result of recording a valuation allowance of $975 million against our deferred tax assets. The effective tax rate for the year ended December 31, 2014 and 2013 differed than the statutory rate primarily due to incremental non-cash income tax expense recorded in conjunction with changing our organizational structure in December 2014, only recording income tax expense subsequent to the Corporate Reorganization on August 30, 2013 (prior to the Corporate Reorganization, we were a partnership), and the level of pretax income during that period.

Income from discontinued operations. Our income from discontinued operations for the year ended December 31, 2014 includes the financial results of assets classified as discontinued operations and gains or losses recorded on the sale of these assets. Income from discontinued operations for the year ended December 31, 2013 includes a $468 million gain on the sale of assets.

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Supplemental Non-GAAP Measures

We use the non-GAAP measures "EBITDAX" and "Adjusted EBITDAX" as supplemental measures. We believe these supplemental measures provide meaningful information to our investors. We define EBITDAX as income (loss) from continuing operations plus interest and debt expense, income taxes, depreciation, depletion and amortization and exploration expense. Adjusted EBITDAX is defined as EBITDAX, adjusted as applicable in the relevant period for the net change in the fair value of derivatives (mark-to-market effects of financial derivatives, net of settlements and cash premiums related to these derivatives), the non-cash portion of compensation expense (which represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans), transition, restructuring and other non-recurring costs, management and other fees paid to the Sponsors (which ended in 2014), losses on extinguishment of debt, equity earnings from Four Star prior to its sale in 2013, and impairment charges.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business, (iii) for evaluating our performance relative to our peers, (iv) to measure our liquidity (before cash capital requirements and working capital needs) and (v) to provide supplemental information about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDAX and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), income (loss) from continuing operations, operating income (loss), operating cash flows or other measures of financial performance or liquidity presented in accordance with GAAP.

Below is a reconciliation of our EBITDAX and Adjusted EBITDAX to our consolidated net (loss) income:

	Year ended December 31,		
	2015	2014	2013
	(in millions)		
Net (loss) income	$(3,748)	$731	$450
Income from discontinued operations, net of tax	—	(4)	(506)
(Loss) income from continuing operations	(3,748)	727	(56)
Income tax (benefit) expense	(578)	432	64
Interest expense, net of capitalized interest	330	318	354
Depreciation, depletion and amortization	983	875	585
Exploration expense	18	22	41
EBITDAX	(2,995)	2,374	988
Mark-to-market on financial derivatives(1)	(667)	(985)	52
Settlements and cash premiums on financial derivatives(2)	942	44	10
Non-cash portion of compensation expense(3)	13	9	31
Transition, restructuring and other costs(4)	8	(4)	8
Fees paid to Sponsors(5)	—	90	26
Loss on extinguishment of debt(6)	41	17	9
Loss from unconsolidated affiliate(7)	—	—	13
Impairment charges	4,299	2	2
Adjusted EBITDAX	$1,641	$1,547	$1,139

(1) Represents the income statement impact of financial derivatives.

(2) Represents actual settlements related to financial derivatives, including cash premiums. No cash premiums were received or paid for the year ended December 31, 2015. For the years ended December 31, 2014 and 2013, we received approximately $1 million and $9 million of cash premiums, respectively.

(3) For the years ended December 31, 2015, 2014 and 2013, cash payments were approximately $8 million, $13 million and $10 million, respectively.

(4) Reflects transition and severance costs related to restructuring for the year ended December 31, 2015. Reflects an $11 million insurance settlement and $5 million of acquisition costs as well as transition and severance costs related to restructuring or asset sales in 2015, 2014 and 2013 and costs incurred related to our initial public offering in 2013.

(5) Represents transaction, management and other fees paid to the Sponsors in 2014.

(6) Represents the loss on extinguishment of debt recorded related to the repayment in May 2015 of our 2019 $750 million senior secured note for the year ended December 31, 2015. Represents the loss on extinguishment of debt recorded related to the retirement of the PIK toggle note in 2014, the redetermination of the RBL Facility and a partial repayment of the term loan in 2013.

(7) Reflects the elimination of equity income (losses) recognized from Four Star, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets, as a result of the sale of Four Star in September 2013.

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Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our RBL Facility. Our primary uses of cash are capital expenditures, debt service including interest, and working capital requirements. As of December 31, 2015, our available liquidity was approximately $1.62 billion.

In November 2015, we completed the semi-annual redetermination of the RBL Facility, reaffirming the borrowing base at $2.75 billion. Our next redetermination date is in April 2016. Our borrowing base, and thus our borrowing capacity, under the RBL Facility is impacted by the level of our oil and natural gas reserves. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant. In 2015, we also extended the maturity date of our RBL Facility from May 2017 to May 2019, provided that our remaining 2018 and 2019 secured term loans are retired or refinanced at least six months prior to their maturity. For further details, see Long-Term Debt below.

We believe we have sufficient liquidity from (i) our cash flows from operations (including our 2016 hedging program), (ii) availability under the RBL Facility and (iii) available cash, to fund our capital program, current obligations and projected working capital requirements for 2016. Furthermore, despite the decline in oil prices, we believe our derivative contracts provide significant commodity price protection on a significant portion of our anticipated oil production for 2016. These derivative contracts, which are primarily fixed price swaps, will allow us to realize a weighted average price of $80.29 per barrel on 18 MMBbls of oil in 2016.

Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the RBL Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all, or (iii) obtain additional capital if required on acceptable terms or at all to fund our capital programs or any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. The extreme ongoing volatility in the energy industry and commodity prices will likely continue to impact our outlook. Our plans are intended to address the impacts of the current volatility in commodity prices while (i) maintaining sufficient liquidity to fund capital in our core drilling programs, (ii) meeting our debt maturities, and (iii) managing and working to strengthen our balance sheet. We continue to implement various cost saving measures to reduce our capital, operating, and general and administrative costs, including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating discretionary costs. In 2015, we realized 20% of capital and 13% of operating cost savings across our programs, and lowered headcount of our general and administrative areas by almost 17%. We will continue to be opportunistic and aggressive in managing our cost structure and, in turn, our liquidity to meet our capital and operating needs.

To the extent commodity prices remain low or decline further, or we experience disruptions in the financial markets impacting our longer-term access to or cost of capital, our ability to fund future growth projects may be further impacted. We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. For example, we could (i) elect to repurchase a portion of our outstanding debt in the future for cash through open market repurchases or privately negotiated transactions with certain of our debtholders or (ii) issue additional secured debt as permitted under our debt agreements, although there is no assurance we would do so. It is also possible additional adjustments to our plan and outlook may occur based on market conditions and the needs of the Company at that time, which could include selling assets, liquidating all or a portion of our hedge portfolio, seeking additional partners to develop our assets, and/or reducing our planned capital program.

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Capital Expenditures. Our capital expenditures and our average drilling rigs for the twelve months ended December 31, 2015 were:

	Capital Expenditures(1) (in millions)	Average Drilling Rigs
Eagle Ford Shale(2)	$855	3.7
Wolfcamp Shale	249	1.2
Altamont	158	1.5
Haynesville Shale	60	0.4
Other	2	—
Total	$1,324	6.8

(1) Represents accrual-based capital expenditures.
(2) Includes approximately $112 million of acquisition capital.

For 2016, we expect our total capital expenditures will be between $500 million to $900 million. These lower levels and wider range of possible capital spending reflect the current volatile and low price environment for oil and natural gas.

Long-Term Debt. As of December 31, 2015, our long-term debt is approximately $4.9 billion, comprised of $3.2 billion in senior notes due in 2020, 2022 and 2023, $647 million in senior secured term loans with maturity dates in 2018 and 2019 and $1,072 million outstanding under the RBL Facility expiring in 2019 (provided that we refinance or retire our senior secured term loans of $500 million due 2018 by November 2017 and $150 million due 2019 by November 2018). For additional details on our long-term debt, including restrictive covenants under our debt agreements, see Part II, Item 8, “Financial Statements and Supplementary Data”, Note 8.

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Overview of Cash Flow Activities. Our cash flows from operations (which include both continuing and discontinued activities) are summarized as follows:

	Year ended December 31,		
	2015	2014	2013
		(in millions)	
Cash Flow from Operations			
Operating activities			
Net (loss) income	$(3,748)	$731	$450
Impairment charges	4,299	20	46
Gain on sale of assets	—	(2)	(468)
Other income adjustments	497	1,390	863
Change in assets and liabilities	279	(953)	69
Total cash flow from operations	$1,327	$1,186	$960
Other Cash Inflows			
Investing activities			
Proceeds from the sale of assets and investments, net of cash transferred	$1	$154	$1,451
Financing activities			
Proceeds from issuance of long-term debt	2,067	2,455	1,880
Proceeds from issuance of stock	—	669	—
Contributions	—	—	17
	2,067	3,124	1,897
Total cash inflows	$2,068	$3,278	$3,348
Cash Outflows			
Investing activities			
Cash paid for capital expenditures	$1,433	$2,033	$1,924
Cash paid for acquisitions, net of cash acquired	111	165	2
	$1,544	$2,198	$1,926
Financing activities			
Repayments of long-term debt	1,826	2,293	2,190
Distributions to members	—	—	205
Debt issuance costs	20	1	5
Other	1	1	—
	1,847	2,295	2,400
Total cash outflows	$3,391	$4,493	$4,326
Net change in cash and cash equivalents	$4	$(29)	$(18)

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Contractual Obligations

We are party to various contractual obligations. Some of these obligations are reflected in our financial statements, such as liabilities from commodity-based derivative contracts, while other obligations, such as operating leases and capital commitments, are not reflected on our balance sheet. The following table and discussion summarizes our contractual cash obligations as of December 31, 2015, for each of the periods presented:

	2016	2017- 2018	2019 - 2020	Thereafter	Total
			(in millions)		
Long-term financing obligations:					
Principal	$—	$500	$3,222	$1,150	$4,872
Interest	320	630	421	170	1,541
Liabilities from derivatives	—	8	—	—	8
Operating leases	12	22	—	—	34
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	82	171	151	109	513
Other obligations	82	45	1	—	128
Total contractual obligations	$496	$1,376	$3,795	$1,429	$7,096

Long-term Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt and (ii) current market interest rates and the contractual credit spread for variable rate debt. In 2015, we extended the maturity of our RBL Facility to May 2019, provided that our remaining 2018 and 2019 secured term loans are retired or refinanced at least six months prior to their maturity. The table above assumes these refinancings occur and and our RBL Facility matures in 2019.

Liabilities from Derivatives. These amounts include the fair value of our commodity-based and interest rate derivative liabilities.

Operating Leases. Amounts include leases related to our office space and various equipment.

Other Contractual Commitments and Purchase Obligations. Other contractual commitments and purchase obligations are legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations. Included are the following:

- Volume and Transportation Commitments. Included in these amounts are commitments for volume deficiency contracts and demand charges for firm access to natural gas transportation as well as firm oil capacity.
- Other Obligations. Included in these amounts are commitments for drilling, completions and seismic activities for our operations and various other maintenance, engineering, procurement and construction contracts. Our future commitments under these contracts may change reflecting changes in commodity prices and any related effect on the supply/demand for these services. We have excluded asset retirement obligations and reserves for litigation and environmental remediation, as these liabilities are not contractually fixed as to timing and amount.

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Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part II, Item 8, "Financial Statements and Supplementary Data", Note 9.

Off-Balance Sheet Arrangements

We have no investments in unconsolidated entities or persons that could materially affect our liquidity or the availability of capital resources. We do not have any material off-balance sheet arrangements that have, or are reasonably likely to have, a material effect on our financial condition or results of operations.

Critical Accounting Estimates

Our significant accounting policies are described in Note 1 of our consolidated financial statements included elsewhere in this Annual Report on Form 10-K. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amount of assets, liabilities, revenue and expense and the disclosures of contingent assets and liabilities. We consider our critical accounting estimates to be those estimates that require complex or subjective judgment in the application of the accounting policy and that could significantly impact our financial results based on changes in those judgments. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Our management has identified the following critical accounting estimates:

Accounting for Oil and Natural Gas Producing Activities. We apply the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, non-drilling exploratory costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred while acquisition costs, development costs and the costs of drilling wells are capitalized. If a well is exploratory in nature, such costs are capitalized, pending the determination of proved oil and gas reserves. As a result, at any point in time, we may have capitalized costs on our consolidated balance sheet associated with exploratory wells that may be charged to exploration expense in a future period. Costs of drilling exploratory wells that do not result in proved reserves are expensed. Under this method, we also capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities. Depreciation, depletion, amortization and the impairment of oil and natural gas properties is calculated on a depletable unit basis based on estimates of proved quantities of proved oil and natural gas reserves. Revisions to these estimates can alter our depletion rates in the future and affect our future depletion expense or assessment of impairment.

We evaluate capitalized costs related to proved properties at least annually or upon a triggering event (such as a significant continued forward commodity price decline) to determine if impairment of such properties has occurred. Our evaluation of whether costs are recoverable is made based on common geological structure or stratigraphic conditions (for example, we evaluate proved property for impairment separately for each of our operating areas), and the evaluation considers estimated future cash flows for all proved developed (producing and non-producing), proved undeveloped reserves and risk-weighted non-proved reserves in comparison to the carrying amount of the proved properties. Important assumptions in the determination of these cash flows are estimates of future oil and gas production, estimated forward commodity prices as of the date of the estimate, adjusted for geographical location and contractual and quality differentials and estimates of future operating and development costs. If the carrying amount of a property exceeds the estimated undiscounted future cash flows of its reserves, the carrying amount is reduced to estimated fair value through a charge to income. Fair value is calculated by discounting those estimated future cash flows using a risk-adjusted discount rate. The discount rate is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas. Each of these estimates involves a high degree of judgment.

During the year ended December 31, 2015, we recorded a non-cash impairment of approximately $4.0 billion on our proved property costs in our Eagle Ford area due to the impact of the continued significant decline in commodity prices during the fourth quarter. While we did not record impairments of the proved property costs in our other operating areas, further declines in prices could result in additional impairments of proved property costs in these other operating areas or additional Eagle Ford impairments. As of December 31, 2015, our remaining capitalized costs related to proved properties were approximately $1,151 million for Eagle Ford, $1,762 million for Wolfcamp, $1,316 million for Altamont and $320 million for Haynesville.

Capitalized costs associated with unproved properties (e.g. leasehold acquisition costs associated with non-producing areas) are also assessed for impairment based on estimated drilling plans and capital expenditures which may also change relative to forward commodity prices and/or potential lease expirations. Generally, economic recovery of unproved reserves in non-producing areas are not yet supported by actual production or conclusive formation tests, but must be confirmed by continued exploration and development activities. Our allocation of capital to the development of unproved properties may be

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influenced by changes in commodity prices (e.g. the current low oil price environment), the availability of oilfield services and the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives.

For example, in Wolfcamp we have drilling commitments that obligate us to drill a specific number of wells by March 2018 in order to hold all of our acreage. Based on the significant decline in commodity prices, we reduced our capital expenditures in Wolfcamp in 2015 and in our other areas where we have leasehold costs, and anticipate we may continue to do so if prices do not return to more economic levels. As a result of continued declines in forecasted oil prices and the potential impact on future development plans as well as the absence of a definitive agreement to extend our Wolfcamp drilling commitment on more favorable terms, during the fourth quarter of 2015 we recorded an impairment of $288 million related to our Wolfcamp unproved property costs. Our ability to ultimately retain our leases and thus recover our non-producing leasehold costs will be dependent upon a number of factors including our levels of drilling activity, which may include drilling the acreage on our behalf or jointly with partners, or our ability to modify or extend these leases. Among other factors, should future oil prices not justify sufficient capital allocation to the continued development of these unproved properties, we could incur additional impairment charges of our unproved property in the future. Our remaining unproved property costs were approximately $168 million at December 31, 2015, of which approximately $97 million was associated with Wolfcamp and the remainder with Altamont and Haynesville.

Estimates of proved reserves reflect quantities of oil, natural gas and NGLs which geological and engineering data demonstrate, with reasonable certainty, will be recoverable in future years from known reservoirs under existing economic conditions. These estimates of proved oil and natural gas reserves primarily impact our property, plant and equipment amounts on our balance sheets and the depreciation, depletion and amortization amounts including any impairment charges on our consolidated income statements, among other items. The process of estimating oil and natural gas reserves is complex and requires significant judgment to evaluate all available geological, geophysical engineering and economic data. Our proved reserves are estimated at a property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers who work closely with the operating groups. These engineers interact with engineering and geoscience personnel in each of our areas and accounting and marketing personnel to obtain the necessary data for projecting future production, costs, net revenues and economic recoverable reserves. Reserves are reviewed internally with senior management quarterly and presented to the board of directors, in summary form on an annual basis. Additionally, on an annual basis each property is reviewed in detail by our centralized and operating divisional engineers to evaluate forecasts of operating expenses, netback prices, production trends and development timing to ensure they are reasonable. Our proved reserves are reviewed by internal committees and the processes and controls used for estimating our proved reserves are reviewed by our internal auditors. In addition, a third-party reservoir engineering firm, which is appointed by and reports to the Audit Committee of the board of directors, conducts an audit of the estimates of a significant portion of our proved reserves. As of December 31, 2015, 53% of our total proved reserves were undeveloped and 3% were developed, but non-producing. The data for a given field may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increase the likelihood of significant changes in these estimates.

Asset Retirement Obligations. The accounting guidance for future abandonment costs requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Future abandonment costs include estimated costs to dismantle and relocate or dispose of our production facilities and gathering systems, wells (or well bores), and restoration costs of land. We develop estimates of these costs for each of our properties based upon their geographic location, type of production facility, reservoir depth and characteristics, market demand for equipment, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and abandonment costs on an annual basis, or more frequently if an event occurs or circumstances change that would affect our assumptions and estimates. Additionally, inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments and estimates of pricing which can impact the timing of the asset retirement obligation. As of December 31, 2015, our asset retirement liability was approximately $41 million.

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Derivatives. We record derivative instruments at their fair values. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing quotes, interest rates, data and valuation techniques that incorporate specific contractual terms, derivative modeling techniques and present value concepts. One of the primary assumptions used to estimate the fair value of commodity-based derivative instruments is price. Our pricing assumptions are based upon price curves derived from actual prices observed in the market, pricing information supplied by a third-party valuation specialist and independent pricing sources and models that rely on this forward pricing information. The extent to which we rely on pricing information received from third parties in developing these assumptions is based, in part, on whether the information considers the availability of observable data in the marketplace. For example, in relatively illiquid markets we may make adjustments to the pricing information we receive from third parties based on our evaluation of whether third party market participants would use pricing assumptions consistent with these sources.

The table below presents the hypothetical sensitivity of our commodity-based derivatives to changes in fair values arising from immediate selected potential changes in oil and natural gas prices at December 31, 2015:

		Change in Price			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Commodity-based derivatives—net assets (liabilities)	$770	$676	$(94)	$864	$94

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to credit and non-performance risk. We adjust the fair value of our derivative assets based on our counterparty's creditworthiness and the risk of non-performance. These adjustments are based on applicable credit ratings, bond yields, changes in actively traded credit default swap prices (if available) and other information related to non-performance and credit standing.

Deferred Taxes and Uncertain Income Tax Positions. As a result of our Corporate Reorganization in 2013, we began recording deferred income tax assets and liabilities reflecting the tax consequences of differences between the financial statement carrying value of assets and liabilities and the tax basis of those assets and liabilities. Our deferred tax assets and liabilities reflect our conclusions about which positions are more likely than not to be sustained if they are audited by taxing authorities. Uncertain tax positions, including deductions or other positions taken on our tax returns, involve the exercise of significant judgment which could change or be challenged by taxing authorities and could impact our financial condition or results of operations.

Valuation Allowances. We assess the available positive and negative evidence to estimate whether sufficient future taxable income will be generated to permit the use of existing deferred tax assets. When it is more likely than not that we will not be able to realize all or a portion of such asset, we record a valuation allowance. As of December 31, 2015, on the basis of this evaluation, we recorded a valuation allowance of $975 million on our deferred tax assets. We evaluate our valuation allowances each reporting period and the level of such allowance will change as our deferred tax balances change. Key estimates and assumptions include expectations of future taxable income, the ability and our intent to undertake transactions that will allow us to realize the asset, all of which involve judgment. Changes in these estimates or assumptions can have a significant effect on our operating results. As of December 31, 2015, we had $23 million of capital loss carry forwards and $2.0 billion and $315 million of federal and state NOL carry forwards, respectively. Our tax basis in our assets also exceeded our book basis. As of December 31, 2014, our valuation allowance was $1 million.

ITEM 7A. Qualitative and Quantitative Disclosures About Market Risk

We are exposed to market risks in our normal business activities. Market risk is the potential loss that may result from market changes associated with an existing or forecasted financial or commodity transaction. The types of market risks we are exposed to and examples of each are:

Commodity Price Risk

- changes in oil, natural gas and NGLs prices impact the amounts at which we sell our production and affect the fair value of our oil and natural gas derivative contracts; and

- changes in locational price differences also affect amounts at which we sell our oil, natural gas and NGLs production, and the fair values of any related derivative products.

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Interest Rate Risk

- changes in interest rates affect the interest expense we incur on our variable-rate debt and the fair value of fixed-rate debt;
- changes in interest rates result in increases or decreases in the unrealized value of our derivative positions; and
- changes in interest rates used to discount liabilities result in higher or lower accretion expense over time.

Risk Management Activities

Where practical, we manage commodity price and interest rate risks by entering into contracts involving physical or financial settlement that attempt to limit exposure related to future market movements on our cash flows. The timing and extent of our risk management activities are based on a number of factors, including our market outlook, risk tolerance and liquidity. Our risk management activities typically involve the use of the following types of contracts:

- forward contracts, which commit us to purchase or sell energy commodities in the future;
- option contracts, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;
- swap contracts, which require payments to or from counterparties based upon the differential between two prices or rates for a predetermined contractual (notional) quantity; and
- structured contracts, which may involve a variety of the above characteristics.

Many of the contracts we use in our risk management activities qualify as derivative financial instruments. A discussion of our accounting policies for derivative instruments is included in Part II Item 8, Financial Statements and Supplementary data, Note 1 and 6.

For information regarding changes in commodity prices and interest rates during 2015, please see “Management’s Discussion and Analysis of Financial Condition” and “Results of Operations”.

Commodity Price Risk

Oil, Natural Gas and NGLs Derivatives. We attempt to mitigate commodity price risk and stabilize cash flows associated with our forecasted sales of oil and natural gas production through the use of derivative oil and natural gas swaps, basis swaps and option contracts. These contracts impact our earnings as the fair value of these derivatives changes. Our derivatives do not mitigate all of the commodity price risks of our forecasted sales of oil and natural gas production and, as a result, we are subject to commodity price risks on our remaining forecasted production.

Sensitivity Analysis. The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at December 31, 2015:

		Oil, Natural Gas and NGLs Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Price impact[1]	$770	$676	$(94)	$864	$94

		Oil, Natural Gas and NGLs Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Discount Rate[2]	$770	$765	$(5)	$775	$5
Credit rate[3]	$770	$762	$(8)	$774	$4

(1) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in fair values arising from changes in oil, natural gas and NGLs prices.

(2) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in the discount rates we used to determine the fair value of our derivatives.

(3) Presents the hypothetical sensitivity of our commodity-based derivatives to changes in credit risk.

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Interest Rate Risk

Certain of our debt agreements are sensitive to changes in interest rates. The table below shows the maturity of the carrying amounts and related weighted-average effective interest rates on our long-term interest-bearing debt by expected maturity date as well as the total fair value of the debt. The fair value of our long-term debt has been estimated primarily based on quoted market prices for the same or similar issues.

	December 31, 2015								December 31, 2014	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2016	2017	2018	2019	2020	Thereafter	Total	Value	Amounts	Value
					(in millions)					
Fixed rate long-term debt	$—	$—	$—	$—	$2,000	$1,150	$3,150	$1,797	$3,100	$3,111
Average interest rate	8.4 %	8.4 %	8.4 %	8.4 %	7.7 %	6.6 %				
Variable rate long-term debt	$—	$—	$497	$1,222	$—	$—	$1,719	$1,582	$1,498	$1,471
Average interest rate	3.2 %	3.2 %	3.1 %	3.0 %	— %	— %				

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Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index

Below is an index to the items contained in Part II, Item 8, Financial Statements and Supplementary Data

Schedules

All financial statement schedules have been omitted because they are either not required, not applicable or the information required to be presented is included in the financial statements or related notes thereto.

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MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by SEC rules adopted under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is 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. It consists of policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, we used the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2015. The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by Ernst & Young LLP, an independent registered public accounting firm, as stated in their report included herein.

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Report of Independent Registered Public Accounting Firm
The Board of Directors and Stockholders of
EP Energy Corporation

We have audited EP Energy Corporation'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). EP Energy Corporation'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.

In our opinion, EP Energy Corporation 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 EP Energy Corporation as of December 31, 2015 and 2014, and the related consolidated statements of income, cash flows and changes in equity for each of the three years in the period ended December 31, 2015 of EP Energy Corporation and our report dated February 19, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 19, 2016

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Report of Independent Registered Public Accounting Firm
The Board of Directors and Stockholders of
EP Energy Corporation

We have audited the accompanying consolidated balance sheets of EP Energy Corporation as of December 31, 2015 and 2014, and the related consolidated statements of income, cash flows and changes in equity for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 EP Energy Corporation 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), EP Energy Corporation’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 19, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 19, 2016

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)

	Year Ended December 31,		
	2015	2014	2013
Operating revenues			
Oil	$981	$1,705	$1,254
Natural gas	200	284	300
NGLs	60	110	74
Financial derivatives	667	985	(52)
Total operating revenues	1,908	3,084	1,576
Operating expenses			
Oil and natural gas purchases	31	23	25
Transportation costs	116	100	85
Lease operating expense	186	193	147
General and administrative	148	244	229
Depreciation, depletion and amortization	983	875	585
Impairment charges	4,299	2	2
Exploration and other expense	20	25	41
Taxes, other than income taxes	80	129	79
Total operating expenses	5,863	1,591	1,193
Operating (loss) income	(3,955)	1,493	383
Other income (expense)	—	1	(12)
Loss on extinguishment of debt	(41)	(17)	(9)
Interest expense	(330)	(318)	(354)
(Loss) income from continuing operations before income taxes	(4,326)	1,159	8
Income tax (benefit) expense	(578)	432	64
(Loss) income from continuing operations	(3,748)	727	(56)
Income from discontinued operations, net of tax	—	4	506
Net (loss) income	$(3,748)	$731	$450
Basic and diluted net income (loss) per common share			
(Loss) income from continuing operations	$(15.37)	$3.00	$(0.27)
Income from discontinued operations, net of tax	—	0.02	2.43
Net (loss) income	$(15.37)	$3.02	$2.16
Basic and diluted weighted average common shares outstanding	244	242	209

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$26	$22
Accounts receivable		
Customer, net of allowance of $1 in 2015 and less than $1 in 2014	202	234
Other, net of allowance of $1 for 2015 and 2014	15	38
Income tax receivable	3	24
Materials and supplies	24	25
Derivative instruments	694	752
Prepaid assets	5	7
Total current assets	969	1,102
Property, plant and equipment, at cost		
Oil and natural gas properties	7,228	10,241
Other property, plant and equipment	82	76
	7,310	10,317
Less accumulated depreciation, depletion and amortization	2,555	1,589
Total property, plant and equipment, net	4,755	8,728
Other assets		
Derivative instruments	85	297
Unamortized debt issue costs - revolving credit facility	23	25
Other	1	2
	109	324
Total assets	$5,833	$10,154

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
(In millions)

	December 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$79	$142
Other	171	403
Derivative instruments	—	1
Accrued interest	47	53
Asset retirement obligations	1	2
Other accrued liabilities	50	47
Total current liabilities	348	648
Long-term debt	4,812	4,533
Other long-term liabilities		
Deferred income taxes	—	578
Derivative instruments	8	—
Asset retirement obligations	40	40
Other	6	7
Total non-current liabilities	4,866	5,158
Commitments and contingencies (Note 9)		
Stockholders' equity		
Class A shares, $0.01 par value; 550 million shares authorized; 248 million shares issued and outstanding at December 31, 2015; 245 million shares issued and outstanding at December 31, 2014	2	2
Class B shares, $0.01 par value; 0.8 million shares authorized, issued and outstanding at December 31, 2015 and December 31, 2014	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Additional paid-in capital	3,529	3,510
(Accumulated deficit) Retained earnings	(2,912)	836
Total stockholders' equity	619	4,348
Total liabilities and equity	$5,833	$10,154

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2015	2014	2013
Cash flows from operating activities			
Net (loss) income	$(3,748)	$731	$450
Adjustments to reconcile net (loss) income to net cash provided by operating activities			
Depreciation, depletion and amortization	983	883	666
Gain on sale of assets	—	(2)	(468)
Deferred income tax (benefit) expense	(578)	435	67
Loss from unconsolidated affiliate, net of cash distributions	—	—	37
Impairment charges	4,299	20	46
Loss on extinguishment of debt	41	17	9
Share-based compensation expense	19	13	22
Non-cash portion of exploration expense	14	19	39
Amortization of debt issuance costs	18	21	22
Other	—	2	1
Asset and liability changes			
Accounts receivable	55	7	(50)
Accounts payable	(70)	13	80
Derivative instruments	277	(939)	56
Accrued interest	(6)	—	(3)
Other asset changes	22	5	(13)
Other liability changes	1	(39)	(1)
Net cash provided by operating activities	1,327	1,186	960
Cash flows from investing activities			
Cash paid for capital expenditures	(1,433)	(2,033)	(1,924)
Proceeds from the sale of assets and investments, net of cash transferred	1	154	1,451
Cash paid for acquisitions, net of cash acquired	(111)	(165)	(2)
Net cash used in investing activities	(1,543)	(2,044)	(475)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	2,067	2,455	1,880
Repayments of long-term debt	(1,826)	(2,293)	(2,190)
Proceeds from issuance of stock	—	669	—
Distributions to members	—	—	(205)
Contributions from members	—	—	17
Debt issuance costs	(20)	(1)	(5)
Other	(1)	(1)	—
Net cash provided by (used in) financing activities	220	829	(503)
Change in cash and cash equivalents	4	(29)	(18)
Cash and cash equivalents			
Beginning of period	22	51	69
End of period	$26	$22	$51

Supplemental cash flow information			
Interest paid, net of amounts capitalized	$312	$289	$305
Income tax (refunds) payments net of refunds	(22)	26	16

See accompanying notes.

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EP ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(In millions)

	Stockholders' Equity Class A Stock		Class B Stock					
	Shares	Amount	Shares	Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity	Members' Equity
Balance at January 1, 2013		$—		$—	$—	$ —	$ —	$2,748
Share-based compensation		—		—	—	—	—	15
Member's distribution		—		—	—	—	—	(205)
Net income		—		—	—	—	—	345
Corporate reorganization	209	—	0.9	—	2,903	—	—	(2,903)
Balance at August 31, 2013 (Corporate Reorganization)	209	$—	0.9	$—	$2,903	$ —	$ 2,903	$—
Income taxes recorded upon corporate reorganization		—		—	(78)	—	(78)	
Share-based compensation		—		—	7	—	7	
Net income		—		—	—	105	105	
Balance at December 31, 2013	209	$—	0.9	$—	$2,832	$ 105	$ 2,937	
Share-based compensation	1	—	(0.1)	—	11	—	11	
Initial public offering of common stock	35	2	—	—	667	—	669	
Net income	—	—	—	—	—	731	731	
Balance at December 31, 2014	245	$2	0.8	$—	$3,510	$ 836	$ 4,348	
Share-based compensation	3	—	—	—	19	—	19	
Net loss	—	—	—	—	—	(3,748)	(3,748)	
Balance at December 31, 2015	248	$2	0.8	$—	$3,529	$ (2,912)	$ 619	

See accompanying notes.

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EP ENERGY CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Consolidation

EP Energy Corporation through its wholly-owned subsidiaries engages in the exploration for and the acquisition, development, and production of oil, natural gas and NGLs in the United States. On August 30, 2013, EP Energy Corporation was reorganized (Corporate Reorganization) as a corporate holding company with a 100% equity interest in EPE Acquisition, LLC. EP Energy Corporation has Class A and Class B common stock. Class A common stock represents the full value of our capital interests and Class B common stock represents profits interests (for further information see Note 10).

Our consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) and include the accounts of all consolidated subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation, including the adoption of accounting standards updates related to the balance sheet classification of deferred taxes and debt issuance costs. None of these reclassifications impacted our reported net income (loss) or stockholders' equity.

We consolidate entities when we have the ability to control the operating and financial decisions of the entity or when we have a significant interest in the entity that gives us the ability to direct the activities that are significant to that entity. The determination of our ability to control, direct or exert significant influence over an entity involves the use of judgment.

Our oil and natural gas properties are managed as a whole in one operating segment rather than through discrete operating segments or business units. We track basic operational data by area and allocate capital resources on a project-by-project basis across our entire asset base without regard to individual areas. We assess financial performance as a single enterprise and not on a geographical area basis.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standards have been issued but not yet been adopted.

Revenue Recognition. In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers, which clarifies the principles for recognizing revenue and develops a common revenue standard for U.S. GAAP and International Financial Reporting Standards. In July 2015, the FASB approved the deferral of the new revenue standard by one year, with the option of early adoption in 2017 or, if not adopted early, beginning in the first quarter of 2018. Retrospective application of this standard is required upon adoption. We are currently evaluating the impact, if any, that this update will have on our financial statements.

Significant Accounting Policies

Use of Estimates

The preparation of our financial statements requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Revenue Recognition

Our revenues are generated primarily through the physical sale of oil, natural gas and NGLs. Revenues from sales of these products are recorded upon delivery and the passage of title using the sales method, net of any royalty interests or other profit interests in the produced product. Revenues related to products delivered, but not yet billed, are estimated each month. These estimates are based on contract data, commodity prices and preliminary throughput and allocation measurements. When actual sales volumes exceed our entitled share of sales volumes, an overproduced imbalance occurs. To the extent the overproduced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, we record a liability.

Costs associated with the transportation and delivery of production are included in transportation costs. We also purchase and sell oil and natural gas on a monthly basis to manage our overall oil and natural gas production and sales. These transactions are undertaken to optimize prices we receive for our oil and natural gas, to physically move oil and gas to its intended sales point, or to manage firm transportation agreements. Revenue related to these transactions are recorded in oil and

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natural gas sales in operating revenues and associated purchases reflected in oil and natural gas purchases in operating expenses on our consolidated income statement.

For the years ended December 31, 2015, 2014 and 2013, we had two customers that individually accounted for 10 percent or more of our total revenues. The loss of any one customer would not have an adverse effect on our ability to sell our oil, natural gas and NGLs production.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents. As of December 31, 2015 and 2014, we had no restricted cash and less than $1 million of restricted cash, respectively, in other current assets to cover escrow amounts required for leasehold agreements in our operations.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances with other parties if we determine that we will not collect all or part of the outstanding balance. We regularly review collectability and establish or adjust our allowance as necessary using the specific identification method.

Oil and Natural Gas Properties

We account for oil and natural gas properties in accordance with the successful efforts method of accounting for oil and natural gas exploration and development activities.

Under the successful efforts method, (i) lease acquisition costs and all development costs are capitalized and exploratory drilling costs are capitalized until results are determined, (ii) other non-drilling exploratory costs, including certain geological and geophysical costs such as seismic costs and delay rentals, are expensed as incurred, (iii) certain internal costs directly identified with the acquisition, successful drilling of exploratory wells and development activities are capitalized, and (iv) interest costs related to financing oil and natural gas projects actively being developed are capitalized until the projects are evaluated or substantially complete and ready for their intended use if the projects were evaluated as successful.

The provision for depreciation, depletion, and amortization is determined on a basis identified by common geological structure or stratigraphic conditions applied to total capitalized costs plus future abandonment costs net of salvage value, using the unit of production method. Lease acquisition costs are amortized over total proved reserves, and other exploratory drilling and all developmental costs are amortized over total proved developed reserves.

We evaluate capitalized costs related to proved properties at least annually or upon a triggering event to determine if impairment of such properties is necessary. Our evaluation of recoverability is made based on common geological structure or stratigraphic conditions and considers estimated future cash flows for all proved developed (producing and non-producing) and proved undeveloped reserves in comparison to the carrying amount of the proved properties. If the carrying amount of a property exceeds the estimated undiscounted future cash flows, the carrying amount is reduced to estimated fair value through a charge to income. Fair value is calculated by discounting the future cash flows based on estimates of future oil and gas production, estimated or published commodity prices as of the date of the estimate, adjusted for geographical location, contractual and quality differentials, estimates of future operating and development costs, and a risk-adjusted discount rate. The discount rate is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying crude oil and natural gas. Leasehold acquisitions costs associated with non-producing areas are assessed for impairment based on our estimated drilling plans and anticipated capital expenditures related to potential lease expirations.

Property, Plant and Equipment (Other than Oil and Natural Gas Properties)

Our property, plant and equipment, other than our assets accounted for under the successful efforts method, are recorded at their original cost of construction or, upon acquisition, at the fair value of the assets acquired. We capitalize the major units of property replacements or improvements and expense minor items. We depreciate our non-oil and natural gas property, plant and equipment using the straight-line method over the useful lives of the assets which range from four to 15 years.

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Accounting for Asset Retirement Obligations

We record a liability for legal obligations associated with the replacement, removal or retirement of our long-lived assets in the period the obligation is incurred and is estimable. Our asset retirement liabilities are initially recorded at their estimated fair value with a corresponding increase to property, plant and equipment. This increase in property, plant and equipment is then depreciated over the useful life of the asset to which that liability relates. An ongoing expense is recognized for changes in the value of the liability as a result of the passage of time, which we record as depreciation, depletion and amortization expense in our consolidated income statement.

Accounting for Long-Term Incentive Compensation

We measure the cost of long-term incentive compensation based on the grant date fair value of the award. Awards issued under these programs are recognized as either equity awards or liability awards based on their characteristics. Expense is recognized in our consolidated financial statements as general and administrative expense over the requisite service period, net of estimated forfeitures. See Note 10 for further discussion of our long-term incentive compensation.

Environmental Costs, Legal and Other Contingencies

Environmental Costs. We record environmental liabilities at their undiscounted amounts on our consolidated balance sheet in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our environmental liabilities are based on current available facts, existing technology and presently enacted laws and regulations, taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period charge in general and administrative expense when clean-up efforts do not benefit future periods.

We evaluate any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties, including insurance coverage, separately from our liability. Recovery is evaluated based on the creditworthiness or solvency of the third party, among other factors. When recovery is assured, we record and report an asset separately from the associated liability on our consolidated balance sheet.

Legal and Other Contingencies. We recognize liabilities for legal and other contingencies when we have an exposure that indicates it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. Where the most likely outcome of a contingency can be reasonably estimated, we accrue a liability for that amount. Where the most likely outcome cannot be estimated, a range of potential losses is established and if no one amount in that range is more likely than any other to occur, the low end of the range is accrued.

Derivatives

We enter into derivative contracts on our oil and natural gas products primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. We also use derivatives to reduce the risk of variable interest rates. Derivative instruments are reflected on our balance sheet at their fair value as assets and liabilities. We classify our derivatives as either current or non-current assets or liabilities based on their anticipated settlement date. We net derivative assets and liabilities with counterparties where we have a legal right of offset.

All of our derivatives are marked-to-market each period and changes in the fair value of our commodity based derivatives, as well as any realized amounts, are reflected as operating revenues. Changes in the fair value of our interest rate derivatives are reflected as interest expense. We classify cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of our oil and natural gas operations, they are classified as cash flows from operating activities. In our consolidated balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables. See Note 6 for a further discussion of our derivatives.

Income Taxes

We record current income taxes based on our estimates of current taxable income and provide for deferred income taxes to reflect estimated future income tax payments and receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. As a result of adopting ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes, as of December 31, 2015, we are required to classify all deferred tax assets and liabilities, along with any related valuation allowance, as non-current on the balance sheet. Pursuant to

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adopting this accounting standard update, we reclassified $251 million of current deferred income tax liabilities as of December 31, 2014 as non-current deferred income tax liabilities. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available.
The realization of our deferred tax assets depends on recognition of sufficient future taxable income during periods in which those temporary differences are deductible. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances. In evaluating our valuation allowances, we consider cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in eligible carryback years, various tax-planning strategies and future taxable income, the latter two of which involve the exercise of significant judgment. Changes to our valuation allowances could materially impact our results of operations.

2. Acquisitions and Divestitures

Acquisitions. On September 4, 2015, we acquired approximately 12,000 net acres adjacent to our existing Eagle Ford Shale acreage for an adjusted cash purchase price of approximately $111 million. Our consolidated balance sheet presented as of December 31, 2015, reflects our allocation of the purchase price to the underlying acquired properties. In 2014, we acquired producing properties and undeveloped acreage in the Southern Midland Basin, of which 37,000 net acres are adjacent to our existing Wolfcamp Shale position, for an aggregate cash purchase price of approximately $152 million. The acquisition represented an approximate 25% expansion of our Wolfcamp acreage. No goodwill or bargain purchase was recorded on these acquisitions.

Discontinued Operations. In 2014 and 2013, we reflected as discontinued operations certain assets sold for approximately $111 million and $1.3 billion, respectively, including (i) certain domestic natural gas assets in the Arklatex area and South Louisiana Wilcox areas sold in May 2014, (ii) domestic natural gas assets which closed in June 2013 (including CBM properties located in the Raton, Black Warrior and Arkoma basins; Arklatex conventional natural gas assets located in East Texas and North Louisiana, and legacy South Texas conventional natural gas assets) and (iii) our Brazilian operations which closed in August 2014. We classified the results of operations of these assets prior to their sale as income (loss) from discontinued operations. Summarized operating results of our discontinued operations were as follows:

	Year Ended December 31,	
	2014	2013
	(in millions)	
Operating revenues	$82	$361
Operating expenses		
Natural gas purchases	—	19
Transportation costs	5	25
Lease operating expense	31	92
Depreciation, depletion and amortization	8	81
Impairment and ceiling test charges(1)	18	44
Other expense	17	53
Total operating expenses	79	314
Gain on sale of assets	2	468
Other income (expense)	4	(2)
Income from discontinued operations before income taxes	9	513
Income tax expense	5	7
Income from discontinued operations, net of tax	$4	$506

(1) During the years ended December 31, 2014 and 2013, we recorded $18 million and $44 million, respectively, in impairment charges related to the sale of our Brazilian operations.

Other Divestitures. In 2014, we also sold certain non-core acreage in Atascosa County in the Eagle Ford Shale for approximately $28 million. During 2013, we (i) received approximately $10 million from the sale of certain domestic oil and natural gas properties and (ii) sold our approximate 49% equity interest in Four Star Oil & Gas Company (Four Star) for proceeds of approximately $183 million. We did not record a gain or loss on the sale of any of these other domestic properties; however, in connection with entering into the sale of Four Star, we recorded a $20 million impairment reflected in other income (expense) on our income statement.

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3. Impairment Charges

We evaluate capitalized costs related to proved properties at least annually or upon a triggering event (such as a significant continued forward commodity price decline) to determine if impairment of such properties has occurred. Capitalized costs associated with unproved properties (e.g. leasehold acquisition costs associated with non-producing areas) are also assessed for impairment based on estimated drilling plans and capital expenditures which may also change relative to forward commodity prices and/or potential lease expirations. See Notes 1 and 7 for a further discussion of our oil and natural gas properties and related significant accounting policies.

Eagle Ford. During the fourth quarter of 2015, we recorded a non-cash impairment charge of approximately $4.0 billion of our proved properties in the Eagle Ford Shale reflecting a reduction in the net book value of the proved property in this area to its estimated fair value due primarily to a significant decline in estimated forward commodity prices.

Wolfcamp. In the Wolfcamp Shale, we have drilling commitments that obligate us to drill a specific number of wells by March 2018 in order to hold all of our acreage. Because of the current oil price environment, we reduced our estimated future capital spending in Wolfcamp. Due to this estimated decline in activity and the absence of a definitive agreement to extend our Wolfcamp lease, we recorded a non-cash impairment charge of $288 million of our unproved properties in the Wolfcamp Shale.

Commodity prices have remained volatile subsequent to December 31, 2015 and have further declined. Further price declines from these levels and/or changes to our future capital, production rates, levels of proved reserves and development plans as a consequence of the lower price environment, may result in an additional impairment of the carrying value of our proved and/or unproved properties in the future.

Other. During the years ended December 31, 2015, 2014 and 2013, we recorded $2 million in impairments on oil inventory and on certain materials and supplies to reflect a market value lower than the underlying cost of those items.

4. Income Taxes

General. On August 30, 2013, we became a corporation subject to federal and state income taxes. As a result, we began recording the effects of income taxes in our financial statements on that date and recorded $78 million as a reduction to additional paid-in capital on our statement of changes in equity which represented the initial net current and deferred tax liabilities. From May 25, 2012 until August 30, 2013, we were a limited liability company treated as a partnership for federal and state income tax purposes.

Pretax Income (Loss) and Income Tax Expense (Benefit). The tables below show the pretax income (loss) from continuing operations and the components of income tax expense (benefit) from continuing operations for the following periods:

	Year Ended December 31,		
	2015	2014	2013
	(in millions)		
Pretax Income (Loss)			
U.S.	$(4,326)	$1,159	$8
Components of Income Tax Expense (Benefit)			
Current			
Federal	$—	$—	$(2)
Deferred			
Federal	(543)	415	59
State	(35)	17	7
	(578)	432	66
Total income tax (benefit) expense	$(578)	$432	$64

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Effective Tax Rate Reconciliation. Income taxes included in net income differs from the amount computed by applying the statutory federal income tax rate of 35% for the following reasons for the following periods:

	Year Ended December 31,		
	2015	2014	2013
		(in millions)	
Income taxes at the statutory federal rate of 35%	$(1,514)	$406	$3
Increase (decrease)			
State income taxes, net of federal income tax effect	(41)	12	4
Partnership earnings not subject to tax	—	—	57
Non-deductible reorganization costs	—	10	—
Valuation allowance	975	—	—
Other	2	4	—
Income tax (benefit) expense	$(578)	$432	$64

The effective tax rate for the year ended December 31, 2015 was 13.4%, lower than the statutory rate of 35% as a result of recording a valuation allowance of $975 million against our deferred tax assets. The effective tax rate for the year ended December 31, 2014 differed from the statutory rate primarily due to the result of state income taxes, net of federal income tax effect and non-deductible reorganization costs recorded in conjunction with changing our organizational structure in 2014. The effective tax rate for the year ended December 31, 2013 differed from the statutory rate primarily due to recording income tax expense subsequent to the Corporate Reorganization on August 30, 2013 and the level of pretax income not subject to tax during those periods.

If we had recorded income taxes effective January 1, 2013, through December 31, 2013, pro forma income from continuing operations would have been approximately $5 million based on applying a federal statutory tax rate of 35%.

Deferred Tax Assets and Liabilities. The following are the components of net deferred tax assets and liabilities:

	December 31, 2015	December 31, 2014
	(in millions)	
Deferred tax assets		
Property, plant and equipment	$471	$—
Net operating loss carryovers	720	532
U.S. tax credit carryovers	10	10
Employee benefits	4	1
Legal and other reserves	7	5
Asset retirement obligations	19	15
Transaction costs	22	21
Total deferred tax assets	1,253	584
Valuation allowance	(976)	(1)
Net deferred tax assets	277	583
Deferred tax liabilities		
Property, plant and equipment	—	794
Financial derivatives	277	367
Total deferred tax liabilities	277	1,161
Net deferred tax liabilities	$—	$578

Unrecognized Tax Benefits. As of December 31, 2015 there were no unrecognized tax benefits as income taxes in our financial statements. We did not recognize any interest and penalties related to unrecognized tax benefits (classified as income taxes in our consolidated income statements) in 2015 or 2014, nor do we have any accrued interest and penalties in our consolidated balance sheet as of December 31, 2015 and December 31, 2014. The Company's and certain subsidiaries income tax years remain open and subject to examination by both federal and state tax authorities. In the third quarter of 2015, we were notified of an IRS examination of one of our subsidiary’s 2013 U.S. tax return.

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Net Operating Loss and Tax Credit Carryovers. The table below presents the details of our federal and state net operating loss carryover periods as of December 31, 2015 (in millions):

	Expiration Period
	2031 - 2035
U.S. federal net operating loss	$1,997
	2016 - 2035
State net operating loss	$315

In addition to our net operating loss carryovers, we also have (i) U.S. federal alternative minimum tax credit carryovers of $10 million and (ii) capital loss carryovers of $23 million. Our U.S. federal alternative minimum tax credits carry over indefinitely while our capital loss carryovers expire in 2018 if we are unable to generate sufficient capital gains on the sale of assets by that time.

Utilization of $320 million of our federal net operating loss carryovers and $10 million of our alternative minimum tax credit carryovers is subject to the limitations provided under Sections 382 of the Internal Revenue Code. While these limitations restrict the amount of carryovers we could potentially utilize in the next few years, it would not cause any carryovers to expire unused.

Valuation Allowances. As of December 31, 2015 and 2014, we have $976 million and $1 million, respectively, in valuation allowances which we recorded based on our evaluation of whether it was more likely than not that our deferred tax assets would be realized. Our evaluations considered cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in prior carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions. For further information on our assessment of our deferred tax assets and valuation allowances, see Income taxes in Note 1.

5. Earnings Per Share

On January 2, 2014, we completed a 62.553-for-1 stock split of our common stock. We have retrospectively reflected earnings per common share/earnings per member unit (each member unit was converted into an equivalent common share in connection with the August 2013 Corporate Reorganization), giving effect to the stock split. Additionally, as of and for periods subsequent to our Corporate Reorganization on August 30, 2013, common share disclosures on our statement of changes in equity reflect the effects of the stock split. On January 23, 2014, we completed a public offering of 35.2 million shares of Class A Common Stock, $0.01 par value per share. We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income from continuing operations per common share is antidilutive. For the year ended December 31, 2015, we incurred losses from continuing operations and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive. Potentially dilutive securities consist of our employee stock options and restricted stock which did not have a material effect upon our diluted earnings per share for the year ended December 31, 2014.

6. Fair Value Measurements

We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each of the levels are described below:

- Level 1 instruments' fair values are based on quoted prices in actively traded markets.
- Level 2 instruments' fair values are based on pricing data representative of quoted prices for similar assets and liabilities in active markets (or identical assets and liabilities in less active markets).
- Level 3 instruments' fair values are partially calculated using pricing data that is similar to Level 2 instruments, but also reflect adjustments for being in less liquid markets or having longer contractual terms.

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The following table presents the carrying amounts and estimated fair values of our financial instruments:

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt	$4,869	$3,379	$4,598	$4,582
Derivative instruments	$771	$771	$1,048	$1,048

For the years ended December 31, 2015 and 2014, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. We hold long-term debt obligations (see Note 8) with various terms. We estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk.

Oil, Natural Gas and NGLs Derivative Instruments. We attempt to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil and natural gas through the use of financial derivatives. As of December 31, 2015 and 2014, we had fixed price derivative contracts for 23 MMBbls and 37 MMBbls of oil and 7 TBtu and 69 TBtu of natural gas, respectively. In addition, we have derivative contracts related to locational basis differences and/or timing of physical settlement prices. As of December 31, 2015, we also had derivative contracts on 15 MMGal of propane. None of these contracts are designated as accounting hedges.

As of December 31, 2015 and 2014, all derivative financial instruments were classified as Level 2. Our assessment of the level of an instrument can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of our financial instruments between other levels.

The following table presents the fair value associated with our derivative financial instruments as of December 31, 2015 and 2014. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

	Level 2							
	Derivative Assets				Derivative Liabilities			
	Gross Fair Value	Impact of Netting	Balance Sheet Location		Gross Fair Value	Impact of Netting	Balance Sheet Location	
			Current	Non-current			Current	Non-current
		(in millions)				(in millions)		
December 31, 2015								
Derivative instruments	$795	$(16)	$694	$85	$(24)	$16	$—	$(8)
December 31, 2014								
Derivative instruments	$1,093	$(44)	$752	$297	$(45)	$44	$(1)	$—

For the years ended December 31, 2015, 2014 and 2013, we recorded derivative gains of $667 million and $985 million and a derivative loss of $52 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statement.

Interest Rate Derivative Instruments. We have interest rate swaps with a notional amount of $600 million that extend through March 2017 and are intended to reduce variable interest rate risk. As of December 31, 2015 and 2014, we had a net asset of $1 million and $3 million, respectively, related to interest rate derivative instruments included in our consolidated balance sheets. For both of the years ended December 31, 2015 and 2014, we recorded $5 million of interest expense and for the year ended December 31, 2013, we recorded $3 million of interest income related to the change in fair market value and cash settlements of our interest rate derivative instruments.

Credit Risk. We are subject to the risk of loss on our derivative instruments that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the daily monitoring of our oil, natural gas and NGLs counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords us netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our assets related to derivatives as of December 31, 2015 represent financial instruments from ten counterparties; all of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB+ or better) credit rating and are lenders associated with our $2.75 billion Reserve-based Loan facility (RBL Facility). Subject to the terms of our $2.75 billion RBL Facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the RBL Facility.

Other Fair Value Considerations. During the year ended December 31, 2015, we recorded non-cash impairment charges on our proved properties in the Eagle Ford Shale. The estimation of the fair value of our proved oil and natural gas properties related to the impairment represented a Level 3 fair value measurement. See Notes 1 and 3 for a further discussion of our impairment charges.

7. Property, Plant and Equipment

Oil and Natural Gas Properties. As of December 31, 2015 and 2014, we had approximately $4.8 billion and $8.7 billion of total property, plant, and equipment, net of accumulated depreciation, depletion, and amortization on our balance sheet, substantially all of which related to both proved and unproved oil and natural gas properties. During the fourth quarter of 2015, we recorded a non-cash impairment charge of approximately $4.0 billion of our proved properties in the Eagle Ford Shale and a non-cash impairment charge of $288 million of our unproved properties in the Wolfcamp Shale. See Note 3 for details of the impairment charges.

Our capitalized costs related to proved and unproved oil and natural gas properties by area for the periods ended December 31 were as follows:

	2015	2014
	(in millions)	
Proved		
Eagle Ford	$2,833	$5,862
Wolfcamp	2,174	1,933
Altamont	1,553	1,275
Haynesville	500	442
Total Proved	7,060	9,512
Unproved		
Eagle Ford	—	131
Wolfcamp	97	383
Altamont	64	201
Haynesville	7	14
Total Unproved	168	729
Less accumulated depletion	2,516	1,560
Net capitalized costs for oil and natural gas properties	$4,712	$8,681

During 2015, we transferred approximately $0.3 billion from unproved properties to proved properties. During 2015, 2014 and 2013, we recorded $9 million, $18 million and $36 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of December 31, 2015 or December 31, 2014.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We settle these obligations when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue these obligations when we can estimate the timing and amount of their settlement.

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate between 7-9 percent on a significant portion of our obligations and a projected inflation rate of 2.5 percent. Changes in estimates in the table below represent changes to the expected amount and timing of payments to settle our

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asset retirement obligations. Typically, these changes primarily result from obtaining new information about the timing of our obligations to plug and abandon oil and natural gas wells and the costs to do so. The net asset retirement liability as of December 31 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability for the periods ended December 31 were as follows:

	2015	2014
	(in millions)	
Net asset retirement liability at January 1	$42	$30
Liabilities incurred	4	10
Liabilities settled	(2)	(2)
Accretion expense	3	3
Changes in estimate	(6)	2
Other	—	(1)
Net asset retirement liability at December 31	$41	$42

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. We capitalize interest primarily on the costs associated with drilling and completing wells until production begins. The interest rate used is the weighted average interest rate of our outstanding borrowings. Capitalized interest for the years ended December 31, 2015, 2014 and 2013, was approximately $14 million, $21 million and $19 million, respectively.

8. Long Term Debt

Listed below are our debt obligations as of the periods presented:

	Interest Rate	December 31, 2015	December 31, 2014
		(in millions)	
$2.75 billion RBL credit facility - due May 24, 2019	Variable	$1,072	$852
Senior secured term loan - due May 24, 2018[(1)(3)]	Variable	497	496
Senior secured term loan - due April 30, 2019[(2)(3)]	Variable	150	150
Senior secured notes - due May 1, 2019	6.875%	—	750
Senior unsecured notes - due May 1, 2020	9.375%	2,000	2,000
Senior unsecured notes - due September 1, 2022	7.75%	350	350
Senior unsecured notes - due June 15, 2023	6.375%	800	—
		4,869	4,598
Less unamortized debt issue costs		(57)	(65)
Total long-term debt		$4,812	$4,533

(1) The term loan was issued at 99% of par and carries interest at a specified margin over the LIBOR of 2.75%, with a minimum LIBOR floor of 0.75%. As of December 31, 2015 and 2014, the effective interest rate of the term loan was 3.50%.

(2) The term loan carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of December 31, 2015 and 2014, the effective interest rate for the term loan was 4.50%.

(3) The term loans are secured by a second priority lien on all of the collateral securing the RBL credit facility, and effectively rank junior to any existing and future first lien secured indebtedness of the Company.

Unamortized Debt Issue Costs. As of December 31, 2015 and 2014, we had total unamortized debt issue costs of $80 million and $90 million. Of these amounts $23 million and $25 million, respectively, are associated with our RBL Facility and $57 million and $65 million, respectively, are associated with our senior secured term loans and senior notes. During 2015, we (i) recorded an additional $19 million in deferred financing costs in conjunction with the issuance of our $800 million of 6.375% senior unsecured notes and with the extension of our RBL Facility and (ii) expensed approximately $12 million related to repurchasing our $750 million 6.875% senior secured notes. During 2015, 2014 and 2013, we amortized $18 million, $21 million and $22 million, respectively, of deferred financing costs into interest expense.

As a result of adopting ASU No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, we reclassified unamortized debt issue costs associated with our senior secured term loans and senior notes from unamortized debt issue costs in other assets to a reduction of long-term debt on our consolidated balance sheets. Unamortized debt issue costs associated with our RBL Facility continue to be reflected as unamortized debt issue costs on our consolidated balance sheets. Pursuant to adopting this accounting standard update, we retrospectively reclassified $65 million of unamortized debt issue costs as a reduction of long-term debt as of December 31, 2014.

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Loss on Extinguishment of Debt. In 2015, we issued $800 million of 6.375% senior unsecured notes due in June 2023. We used a substantial portion of the proceeds from the offering to purchase for cash our $750 million senior secured notes due in 2019. In conjunction with repurchasing these notes, we recorded a $41 million loss on extinguishment of debt, of which $12 million was a non-cash expense related to eliminating associated unamortized debt issuance costs. In 2014, we repaid and retired our senior PIK toggle note with a portion of the proceeds from our initial public offering recording a $17 million loss on extinguishment of debt. In 2013, we recorded $9 million in losses on the extinguishment of debt associated with the pro-rata portion of deferred financing costs written off in conjunction with the repayment of a portion of our senior secured term loans, our term loan re-pricing and the semi-annual redetermination of our RBL Facility.

$2.75 Billion Reserve-based Loan Facility. We have a $2.75 billion credit facility in place which allows us to borrow funds or issue letters of credit (LCs). As of December 31, 2015, we had approximately $82 million of LC's issued under the facility, in addition to amounts borrowed, with $1.6 billion of available capacity. Listed below is a further description of our credit facility as of December 31, 2015:

Credit Facility	Maturity Date	Interest Rate	Commitment fees
$2.75 billion RBL	May 24, 2019	LIBOR + 1.75%(1) 1.75% for LCs	0.375% commitment fee on unused capacity

(1) Based on our December 31, 2015 borrowing level. Amounts outstanding under the $2.75 billion RBL Facility bear interest at specified margins over the LIBOR of between 1.50% and 2.50% for Eurodollar loans or at specified margins over the Alternative Base Rate (ABR) of between 0.50% and 1.50% for ABR loans. Such margins will fluctuate based on the utilization of the facility.

In April 2015, we extended the maturity to May 2019, provided that we retire or refinance our 2018 and 2019 secured notes and term loans at least six months prior to their maturity. As noted above, we refinanced our $750 million secured notes in mid-2015. We will be required to retire or refinance our remaining $500 million senior secured term loans due 2018 by November 2017 and $150 million senior secured term loans due 2019 by November 2018.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In November 2015, we completed our semi-annual redetermination, affirming the borrowing base at $2.75 billion. Our next redetermination date for the RBL Facility is in April 2016. Downward revisions of our oil and natural gas reserves due to declines in commodity prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base which could negatively impact our borrowing capacity under the RBL Facility in the future.

Restrictive Provisions/Covenants. The availability of borrowings under our credit agreements and our ability to incur additional indebtedness is subject to various financial and non-financial covenants and restrictions. Our most restrictive financial covenant requires that our debt to EBITDAX ratio, as defined in the credit agreement, must not exceed 4.50 to 1.0 during the current period. Certain other covenants and restrictions, among other things, also limit our ability to incur or guarantee additional indebtedness; make any restricted payments or pay any dividends on equity interests or redeem, repurchase or retire parent entities' equity interests or subordinated indebtedness; sell assets; make investments; create certain liens; prepay debt obligations; engage in transactions with affiliates; and enter into certain hedge agreements. As of December 31, 2015, we were in compliance with our debt covenants.

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9. Commitments and Contingencies

Legal Matters

We and our subsidiaries and affiliates are parties to various legal actions and claims that arise in the ordinary course of our business. For each matter, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of our current matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2015, we had approximately $5 million accrued for all outstanding legal matters.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestitures of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities. For example, the recent decline in commodity prices may create an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging and abandonment obligations that attach to such assets. In that event, under various laws or regulations, we may be required to assume these plugging or abandonment obligations on assets no longer owned and operated by us. As of December 31, 2015, we had approximately $8 million accrued related to these indemnifications and other matters.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. Numerous governmental agencies, such as the EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements.

The environmental laws and regulations to which we are subject also require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2015, we had accrued and had exposure of approximately $1 million for related environmental remediation costs associated with onsite, offsite and groundwater technical studies and for related environmental legal costs. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued. Second, where the most likely outcome cannot be estimated, a range of costs is established and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts that we will expend to remediate these sites.

However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

Climate Change and Other Emissions. The EPA and several state environmental agencies have adopted regulations to regulate GHG emissions. Although the EPA has adopted a “tailoring” rule to regulate GHG emissions, the U.S. Supreme Court partially invalidated it in an opinion decided June 2014. The tailoring rule remains applicable for those facilities considered major sources of six other “criteria” pollutants and at this time we do not expect a material impact to our existing operations from the rule. Any regulations regarding GHG emissions would likely increase our costs of compliance by potentially delaying

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the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric-driven compression at facilities to obtain regulatory permits and approvals in a timely manner.

As part of the White House's Climate Action Plan Strategy to Reduce Methane Emissions, the EPA, the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Bureau of Land Management (BLM) have recently proposed new regulations affecting the oil and gas industry. On September 18, 2015, the EPA published several proposed regulations under the Clean Air Act to reduce methane and volatile organic compounds emissions, in part through green completions at oil wells, fugitive emission surveys, limits on pneumatic pumps and controllers, and draft guidelines for controls on equipment in ozone nonattainment areas. On October 13, 2015, the PHMSA published a proposed rule for oil pipelines, in part requiring inspections in areas affected by natural disasters, expanding use of leak detection systems, and increased use of inline inspection tools. On January 22, 2016, the BLM released a proposed rule for oil and gas facilities on onshore federal and Indian leases to prohibit venting, limit flaring, require leak detection, and allow adjustment of royalty rates for new leases. Although we are examining these proposed regulations, it is uncertain what impact they might have on our operations until they are implemented.

Air Quality Regulations. The EPA has promulgated various performance and emission standards that mandate air pollutant emission limits and operating requirements for stationary reciprocating internal combustion engines and process equipment. We do not anticipate material capital expenditures to meet these requirements.

In August 2012, the EPA promulgated additional standards to reduce various air pollutants associated with hydraulic fracturing of natural gas wells and equipment including compressors, storage vessels, and pneumatic valves. Parts of the new standard were amended August 2013. We do not anticipate material capital expenditures to meet these requirements. Effective December 31, 2014, additional amendments to the new standard were finalized, for which we do not anticipate material capital expenditure.

The EPA has promulgated regulations to require pre-construction permits for minor sources of air emissions in tribal lands as of September 2, 2014. The EPA has twice extended this deadline, to March 2, 2016 and then to October 3, 2016. Meanwhile, the EPA has proposed a federal implementation plan (FIP), rather than a general permit, that incorporates emission limits and other requirements from six standards under the Clean Air Act for the oil and gas industry. Additionally, the proposed FIP would require an operator to document compliance with the Endangered Species Act and National Historic Preservation Act. Until such regulations are adopted, it is uncertain what impact they might have on our operations in tribal lands.

Hydraulic Fracturing Regulations. We use hydraulic fracturing extensively in our operations. Various regulations have been adopted and proposed at the federal, state and local levels to regulate hydraulic fracturing operations. These regulations range from banning or substantially limiting hydraulic fracturing operations, requiring disclosure of the hydraulic fracturing fluids and requiring additional permits for the use, recycling and disposal of water used in such operations. In addition, various agencies, including the EPA and Department of Energy are reviewing changes in their regulations to address the environmental impacts of hydraulic fracturing operations. Until such regulations are implemented, it is uncertain what impact they might have on our operations. In March 2015, the BLM published final rules for hydraulic fracturing on federal and certain tribal lands, including use of tanks for recovered water, updated cementing and testing requirements, and disclosure of chemicals used in hydraulic fracturing. Several states and the Ute Indian Tribe have filed suit to challenge these rules, and on September 30, 2015, a federal court issued a preliminary injunction suspending the rules. No material cost is expected for the Company's 2016 program.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) Matters. As part of our environmental remediation projects, we are or have received notice that we could be designated as a Potentially Responsible Party (PRP) with respect to one active site under the CERCLA or state equivalents. As of December 31, 2015, we have estimated our share of the remediation costs at this site to be less than $1 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro-rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these matters are included in the reserve

for environmental matters discussed above.
Waste Handling. Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements imposed under the Resource Conservation and Recovery Act, as amended, and comparable state laws. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and

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regulations. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

Lease Obligations

We maintain operating leases in the ordinary course of our business activities. These leases include those for office space and various equipment. The terms of the agreements vary through 2018. Future minimum annual rental commitments under non-cancelable future operating lease commitments at December 31, 2015, were as follows:

Year Ending December 31,	Operating Leases (in millions)
2016	$12
2017	13
2018	9
Total	$34

Rental expense for the years ended December 31, 2015, 2014 and 2013 was $12 million, $13 million and $13 million, respectively.

Other Commercial Commitments

At December 31, 2015, we have various commercial commitments totaling $525 million primarily related to commitments and contracts associated with volume and transportation, completion activities and seismic activities. Our annual obligations under these arrangements are $160 million in 2016, $129 million in 2017, $85 million in 2018, $81 million in 2019, and $70 million thereafter.

10. Long-Term Incentive Compensation / 401(k) Retirement Plan

Overview. Under our current stock-based compensation plan (the EP Energy Corporation 2014 Omnibus Incentive Plan, or omnibus plan), we may issue to our employees and non-employee directors various forms of long-term incentive (LTI) compensation including stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares/units, incentive awards, cash awards, and other stock-based awards. We are authorized to grant awards of up to 12,433,749 shares of our common stock for awards under the omnibus plan, with 7,987,514 shares remaining available for issuance as of December 31, 2015. In addition, in conjunction with the acquisition of certain of our subsidiaries by Apollo and other private equity investors in 2012 (the Acquisition), certain employees received other LTI awards based on their purchased equity interests including, but not limited to (i) Class A “matching” units (subsequently converted into common shares upon our Corporate Reorganization) and (ii) Management Incentive Units (subsequently converted into Class B shares upon our Corporate Reorganization) which become payable upon certain liquidity events. At the time of our 2013 Corporate Reorganization, we also issued additional Class B shares to a subsidiary for grants to current and future employees that likewise become payable upon certain liquidity events. No additional Class B shares are available for issuance.

We record stock-based compensation expense as general and administrative expense over the requisite service period, net of estimates of forfeitures. If actual forfeitures differ from our estimates, additional adjustments to compensation expense will be required in future periods. All of these LTI programs are discussed further below.

Restricted stock. We grant shares of restricted common stock which carry voting and dividend rights and may not be sold or transferred until they are vested. The fair value of our restricted stock is determined on the date of grant and these shares generally vest in equal amounts over 3 years from the date of the grant. A summary of the changes in our non-vested restricted shares for the year ended December 31, 2015 is presented below:

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	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2014	1,033,394	$19.80
Granted	3,678,997	$9.40
Vested	(336,268)	$19.59
Forfeited	(388,469)	$12.03
Non-vested at December 31, 2015	3,987,654	$10.98

During 2015 and 2014, we recognized approximately $13 million and $5 million of pre-tax compensation expense, respectively, and recorded deferred income tax benefits of $2 million for both of the years 2015 and 2014 on our restricted share awards. In 2015, we also recorded current income tax expense of $1 million for the vesting of our restricted share awards. The total unrecognized compensation cost related to these arrangements at December 31, 2015 was approximately $30 million, which is expected to be recognized over a weighted average period of 3 years.

Stock Options. We grant stock options as compensation for future service at an exercise price equal to the closing share price of our stock on the grant date. Stock options granted have contractual terms of 10 years and vest in three tranches over a five-year period (with the first tranche vesting on the third anniversary of the grant date, the second tranche vesting on the fourth anniversary of the grant date and the third tranche vesting on the fifth anniversary thereof), but commence vesting earlier in the event of a complete sell-down by certain of our private equity investors of their shares of our common stock. We do not pay dividends on unexercised options. A summary of our stock option transactions for the year ended December 31, 2015 is presented below.

	Number of Shares Underlying Options	Weighted Average Exercise Price per Share	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2014	219,352	$19.82		
Granted	—	$—		
Vested	(638)	$19.82		
Forfeited or canceled	(4,377)	$19.82		
Outstanding at December 31, 2015	214,337	$19.82	8.25	—

For both of the years ended December 31, 2015 and 2014, we recognized less than $1 million of pre-tax compensation expense related to stock options awards granted. Total compensation cost related to non-vested option awards not yet recognized at December 31, 2015 was approximately $1 million, which is expected to be recognized over a weighted average period of 3 years. There were no options exercised during the year.

Fair Value Assumptions. For the year ended December 31, 2015, we did not issue stock options. In 2014, the fair value of each stock option granted was estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions utilizing management's best estimate at the time of grant. For the year ended December 31, 2014, the weighted average grant date fair value per share of options granted was $9.03. Listed below is the weighted average of each assumption based on the grant in 2014:

	2014
Expected Term in Years	7.0
Expected Volatility	40%
Expected Dividends	—
Risk-Free Interest Rate	2.3%

We estimated expected volatility based on an analysis of historical stock price volatility of a group of similar publicly traded peer companies which share similar characteristics with us over the expected term because our stock has been publicly traded for a very short period of time. We estimate the expected term of our option awards based on the vesting period and average remaining contractual term, referred to as the "simplified method." We used this method to provide a reasonable basis for estimating our expected term based on insufficient historical data prior to 2014.

Cash-Based Long Term Incentive. In 2013, we provided long term cash-based incentives to certain of our employees linking annual performance-based cash incentive payments to the financial performance of the company as approved by the Compensation Committee of our board of directors, and the employee's individual performance for the year. Beginning in 2014, no further cash-based awards were granted. Our cash-based LTI awards vested over three-years (50% vesting at the end of the first year, and 25% vesting at the end of each of the succeeding two years), and were treated as liability awards. Cash-based LTI awards granted during 2013 and 2012 had a fair value of $22 million and $24 million on each respective grant date which are amortized primarily on an accelerated basis over the three-year vesting period. For the years ended December 31, 2015, 2014 and 2013, we recorded approximately $2 million, $8 million and $16 million, respectively, in expense related to these awards. As of December 31, 2015, we had unrecognized compensation expense of less than $1 million related to these awards which we will recognize in 2016.

Class A "Matching" Grants. In conjunction with the Acquisition, certain of our employees purchased Class A units. In connection with their purchase of these units, these employees were awarded compensatory awards for accounting purposes including (i) "matching" Class A unit grants with a fair value of $12 million equal to 50% of the Class A units purchased subject to repurchase by the Company in the event of certain termination scenarios and (ii) a "guaranteed cash bonus" with a fair value of $12 million which was treated as a liability award and was paid in March 2013 equivalent to the amount of the "matching" Class A unit grant. In connection with the Corporate Reorganization in August 2013, each "matching" unit was converted into common stock. For the "guaranteed cash bonus", we recognized the fair value as compensation cost ratably over the period from the date of grant (May 24, 2012) through the cash payout date in March 2013. For the "matching" Class A unit grant, we recognize the fair value as compensation cost ratably over the three year period from the date of grant through the period over which the requisite service is provided and the time period at which certain transferability restrictions are removed. For the years ended December 31, 2015, 2014 and 2013, we recognized approximately $2 million, $2 million and $3 million, respectively, as compensation expense related to "matching" Class A unit grants. In 2013, we also recognized $3 million as compensation expense related to other awards granted in conjunction with the Acquisition. As of December 31, 2015, we had unrecognized compensation expense of $1 million related to the "matching" Class A unit grants, which we will recognize in 2016.

Management Incentive Units (MIPs). In addition to the Class A "matching" awards described above, certain employees were awarded MIPs at the time of the Acquisition. These MIPs are intended to constitute profits interests. Each award of MIPs represents a share in any future appreciation of the Company after the date of grant, subject to certain limitations, and once certain shareholder returns have been achieved. The MIPs vest ratably over 5 years subject to certain forfeiture provisions based on continued employment with the Company, although 25% of any vested awards are forfeitable in the event of certain termination events. The MIPs become payable based on the achievement of certain predetermined performance measures (e.g. certain liquidity events in which our private equity investors receive a return of at least one times their invested capital plus a stated return). The MIPs were issued at no cost to the employees and have value only to the extent the value of the Company increases. For accounting purposes, these awards were treated as compensatory equity awards. The MIPs were subsequently converted into Class B common shares on a one-for-one basis in August 2013 in connection with the Corporate Reorganization. On May 24, 2012, the grant date fair value of this award was determined using a non-controlling, non-marketable option pricing model which valued these MIPs assuming a 0.77% risk free rate, a 5 year time to expiration, and a 73% volatility rate. Based on these factors, we determined a grant date fair value of $74 million. For the years ended December 31, 2015, 2014 and 2013, we recognized approximately $4 million, $6 million and $19 million, respectively, as compensation expense related to these awards. As of December 31, 2015, we had unrecognized compensation expense of $4 million. Of this amount, we will recognize $3 million in 2016 and the remainder on an accelerated basis for each tranche of the award, over the remainder of the five year requisite service period. The remaining $16 million of compensation will be recognized upon a specified capital transaction when the right to such amounts become nonforfeitable.

Other. On September 18, 2013, we issued an additional 70,000 shares of Class B common stock to EPE Employee Holdings II, LLC (EPE Holdings II), a subsidiary. EPE Holdings II was formed to hold such shares and serve as an entity through which current and future employee incentive awards will be granted. Holders of the awards will not hold actual Class B common stock or equity in EPE Holdings II, but rather will have a right to receive proceeds paid to EPE Holdings II in respect of such shares which is conditional upon certain events (e.g. certain liquidity events in which our private equity investors receive a return of at least one times their invested capital plus a stated return) that are not yet probable of occurring. As a result, no compensation expense was recognized upon the issuance of the Class B shares to EPE Holdings II, and none will occur until those events that give rise to a payout on such shares becomes probable of occurring. At that time, the full value of the awards issued to EPE Holdings II will be recognized based on actual amounts paid on the Class B common stock.

401(k) Retirement Plan. We sponsor a tax-qualified defined contribution retirement plan for a broad-based group of employees. We make matching contributions (dollar for dollar up to 6% of eligible compensation) and non-elective employer contributions (5% of eligible compensation) to the plan, and individual employees are also eligible to contribute to the defined

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contribution plan. During 2015, 2014 and 2013, we had contributed $10 million, $11 million and $12 million, respectively, of matching and non-elective employer contributions.

11. Related Party Transactions

Affiliate Supply Agreement. For the years ended December 31, 2015, 2014 and 2013, we recorded approximately $67 million, $112 million and $120 million, respectively, in capital expenditures for amounts expended under supply agreements entered into with an affiliate of Apollo Management LLC (Apollo) to provide certain fracturing materials to our Eagle Ford drilling operations.

Management Fee Agreement. In January 2014, we paid a quarterly management fee of $6.25 million to our private equity investors (affiliates of Apollo, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, collectively the Sponsors). Additionally, upon the closing of our initial public offering in January 2014, we paid the Sponsors an additional transaction fee equal to approximately $83 million. We recorded both of these fees in general and administrative expense. Our Management Fee Agreement with the Sponsors, including the obligation to pay the quarterly management fee, terminated automatically in accordance with its terms upon the closing of our initial public offering in January 2014. For the year ended December 31, 2013, we recognized approximately $26 million in general and administrative expense related to the management fee and other sponsor related fees.

Member Distribution. In 2013, we made $205 million in distributions to our members including a leveraged distribution of approximately $200 million.

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Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below (in millions, except per common share amounts).

2015	March 31	June 30	September 30	December 31
Operating revenues				
Physical sales	$290	$368	$319	$264
Financial derivatives	203	(179)	434	209
Operating income (loss)	113	(208)	355	(4,215)
Income tax expense (benefit)	10	(118)	95	(565)
Income (loss) from continuing operations	19	(212)	176	(3,731)
Net income (loss)	19	(212)	176	(3,731)
Basic and diluted net income (loss) per common share				
Income (loss) from continuing operations	$0.08	$(0.87)	$0.72	$(15.29)
Net income (loss)	$0.08	$(0.87)	$0.72	$(15.29)
2014	March 31	June 30	September 30	December 31
Operating revenues				
Physical sales	$511	$566	$572	$450
Financial derivatives	(135)	(290)	381	1,029
Operating (loss) income	(60)	(100)	573	1,080
Income tax (benefit) expense	(56)	(68)	191	365
(Loss) income from continuing operations	(100)	(112)	306	633
Net (loss) income	(90)	(118)	305	634
Basic and diluted net (loss) income per common share				
(Loss) income from continuing operations	$(0.42)	$(0.46)	$1.25	$2.60
Net (loss) income	$(0.38)	$(0.49)	$1.25	$2.60

Below are additional significant items affecting comparability of amounts reported in the respective periods of 2015 and 2014:

December 31, 2015. We recorded a non-cash impairment charge of approximately $4.0 billion of our proved properties and a non-cash impairment charge of $288 million of our unproved properties due to the continued significant decline in commodity prices during the fourth quarter.

June 30, 2015. We recorded $41 million on extinguishment of debt, of which $12 million was a non-cash expense related to eliminating unamortized debt issuance costs in conjunction with refinancing our $750 million senior secured notes.

March 31, 2014. We recorded $90 million of transaction, management and other fees paid to the Sponsors and $17 million in loss on extinguishment of debt for the portion of deferred financing costs written off in conjunction with the repayment and retirement of the PIK toggle note.

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Supplemental Oil and Natural Gas Operations (Unaudited)

We are engaged in the exploration for, and the acquisition, development and production of oil, natural gas and NGLs, in the United States (U.S.). We also had operations in Brazil that were sold in 2014.

In the periods ended December 31, 2014 and 2013, our total costs incurred and results of operations include our Brazilian operations and certain domestic natural gas assets sold, including the South Louisiana Wilcox, CBM, South Texas and Arklatex as discontinued operations. In addition, we sold our approximate 49% equity investment in Four Star in 2013.

Capitalized Costs. Capitalized costs relating to domestic oil and natural gas producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31 (in millions):

	2015	2014
Oil and natural gas properties	$7,228	$10,241
Less accumulated depreciation, depletion and amortization	2,516	1,560
Net capitalized costs(1)	$4,712	$8,681

(1) During the year ended December 31, 2015, we recorded a non-cash impairment charge of approximately $4.0 billion of our proved properties in the Eagle Ford Shale and a non-cash impairment charge of $288 million of our unproved properties in our Wolfcamp Shale.

Total Costs Incurred. Costs incurred in oil and natural gas producing activities, whether capitalized or expensed, were as follows for the years ended December 31, 2015, 2014 and 2013 (in millions):

	U.S.
2015 Consolidated:	
Property acquisition costs	
Proved properties	$111
Unproved properties	12
Exploration costs (capitalized and expensed)	26
Development costs	1,168
Costs expended	1,317
Asset retirement obligation costs	4
Total costs incurred	$1,321
2014 Consolidated:	
Property acquisition costs	
Proved properties	$117
Unproved properties	62
Exploration costs (capitalized and expensed)	57
Development costs	1,953
Costs expended	2,189
Asset retirement obligation costs	10
Total costs incurred	$2,199
2013 Consolidated:	
Property acquisition costs	
Proved properties	$2
Unproved properties	20
Exploration costs (capitalized and expensed)	95
Development costs	1,783
Costs expended	1,900
Asset retirement obligation costs	6

Total costs incurred	$1,906

We capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities. The table above includes capitalized labor costs of $31 million, $38 million and $37 million for the years ended December 31, 2015, 2014 and 2013, and capitalized interest of $14 million, $21 million and $19 million for the same periods.

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Oil and Natural Gas Reserves. Net quantities of proved developed and undeveloped reserves of natural gas, oil and NGLs and changes in these reserves at December 31, 2015 presented in the tables below are based on our internal reserve report. Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at the time of the estimate. Our 2015 proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2015 except for differences of less than five percent resulting from actual production, acquisitions, property sales, necessary reserve revisions and additions to reflect actual experience.

Ryder Scott Company, L.P. (Ryder Scott), conducted an audit of the estimates of the proved reserves that we prepared as of December 31, 2015. In connection with its audit, Ryder Scott reviewed 99% (by volume) of our total proved reserves on a barrel of oil equivalent basis, representing 98% of the total discounted future net cash flows of these proved reserves. For the audited properties, 100% of our total proved undeveloped (PUD) reserves were evaluated. Ryder Scott concluded the overall procedures and methodologies that we utilized in preparing our estimates of proved reserves as of December 31, 2015 complied with current SEC regulations and the overall proved reserves for the reviewed properties as estimated by us are, in aggregate, reasonable within the established audit tolerance guidelines of 10% as set forth in the Society of Petroleum Engineers auditing standards. Ryder Scott's report is included as an exhibit to this Annual Report on Form 10-K.

	Year Ended December 31, 2015(1) U.S.			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	1,243	320,813	94,226	622.2
Revisions due to prices	(44)	(16,288)	(3,880)	(27.5)
Revisions other than prices(2)	(294)	(32,778)	(6,422)	(88.2)
Extensions and discoveries(3)	100	41,189	11,065	68.9
Purchase of reserves	9	7,883	1,252	10.6
Production	(76)	(22,078)	(5,366)	(40.0)
End of year	938	298,741	90,875	546.0
Proved developed reserves:				
Beginning of year	464	128,396	32,474	238.1
End of year	530	131,804	36,442	256.6
Proved undeveloped reserves:				
Beginning of year	779	192,417	61,752	384.1
End of year	408	166,937	54,432	289.4

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $50.28 per Bbl (WTI) and $2.59 per MMBtu (Henry Hub).

(2) Of the 88 MMBoe of revisions other than prices, 85 MMBoe were negative PUD revisions due to the impact of the SEC's five-year development rule after reductions in estimated capital in our long-range development plan based on the lower price environment.

(3) Of the 69 MMBoe of extensions and discoveries, 18 MMBoe are in the Eagle Ford Shale, 32 MMBoe are in the Wolfcamp Shale, 19 MMBoe are in the Altamont area and less than 1 MMBoe are in the Haynesville Shale. Of the 69 MMBoe of extensions and discoveries, 52 MMBoe were liquids representing 76% of EP Energy's total extensions and discoveries.

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	Year Ended December 31, 2014[1][2] U.S.			
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)
Proved developed and undeveloped reserves				
Beginning of year	1,070	293,201	75,605	547.2
Revisions due to prices	205	(1,720)	(538)	31.9
Revisions other than prices	(31)	(8,310)	3,702	(9.8)
Extensions and discoveries[3]	146	59,242	19,805	103.3
Purchase of reserves	9	4,079	1,530	7.1
Sales of reserves in place	(83)	(5,615)	(1,738)	(21.2)
Production	(73)	(20,064)	(4,140)	(36.3)
End of year	1,243	320,813	94,226	622.2
Proved developed reserves:				
Beginning of year	484	83,811	17,647	182.1
End of year	464	128,396	32,474	238.1
Proved undeveloped reserves:				
Beginning of year	586	209,391	57,958	365.1
End of year	779	192,417	61,752	384.1

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $94.99 per Bbl (WTI) and $4.34 per MMBtu (Henry Hub).

(2) Reflects only U.S. oil and natural gas reserves. In 2014, we sold our Brazilian operations with a December 31, 2013 balance of proved developed and undeveloped reserves of 11.6 MMBoe, during 2014 our production was (1.1) MMBoe, positive revisions of 0.4 MMBoe, for a total sales of reserves in place of (10.9) MMBoe.

(3) Of the 103 MMBoe of extensions and discoveries, 2 MMBoe were from assets sold, 68 MMBoe are in the Eagle Ford Shale, 19 MMBoe are in the Wolfcamp Shale, 14 MMBoe are in the Altamont area and 2 MMBoe are in the Haynesville Shale. Of the 103 MMBoe of extensions and discoveries, 79 MMBoe were liquids representing 77% of EP Energy’s total extensions and discoveries.

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	Year Ended December 31, 2013[1]							
	U.S.				Brazil			Total
	Natural Gas (in Bcf)	Oil (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)	Natural Gas (in Bcf)	Oil (in MBbls)	Equivalent Volumes (in MMBoe)	Equivalent Volumes (in MMBoe)
Consolidated								
Proved developed and undeveloped reserves								
Beginning of year	1,727	256,242	34,331	578.5	68	2,152	13.4	591.9
Revisions due to prices	83	376	166	14.4	—	5	—	14.4
Revisions other than prices	129	(36,322)	20,459	5.6	—	(17)	—	5.6
Extensions and discoveries[2]	231	88,174	28,583	155.3	—	—	—	155.3
Sales of reserves in place	(965)	(1,642)	(5,108)	(167.6)	—	—	—	(167.6)
Production	(135)	(13,627)	(2,826)	(39.0)	(9)	(305)	(1.8)	(40.8)
End of year[3]	1,070	293,201	75,605	547.2	59	1,835	11.6	558.8
Proved developed reserves:								
Beginning of year	1,189	55,924	9,080	263.2	68	2,152	13.3	276.5
End of year	484	83,811	17,647	182.1	59	1,835	11.6	193.7
Proved undeveloped reserves:								
Beginning of year	538	200,318	25,251	315.2	—	—	—	315.2
End of year	586	209,391	57,958	365.1	—	—	—	365.1
Unconsolidated Affiliate — Four Star								
Proved developed and undeveloped reserves								
Beginning of year	150	2,148	5,967	33.1	—	—	—	33.1
Revisions due to prices	5	66	191	1.1	—	—	—	1.1
Revisions other than prices	11	128	348	2.3	—	—	—	2.3
Sales of reserves in place	(156)	(2,145)	(6,179)	(34.3)	—	—	—	(34.3)
Production	(10)	(197)	(327)	(2.2)	—	—	—	(2.2)
End of year	—	—	—	—	—	—	—	—
Proved developed reserves:								
Beginning of year	140	2,111	5,289	30.9	—	—	—	30.9
End of year	—	—	—	—	—	—	—	—
Proved undeveloped reserves:								

Beginning of year	10	37	678	2.4	—	—	—	2.4
End of year	—	—	—	—	—	—	—	—
Total Combined								
Proved developed reserves:								
Beginning of year	1,329	58,035	14,369	294.1	68	2,152	13.3	307.4
End of year	484	83,811	17,647	182.1	59	1,835	11.6	193.7
Proved undeveloped reserves:								
Beginning of year	548	200,355	25,929	317.6	—	—	—	317.6
End of year	586	209,391	57,958	365.1	—	—	—	365.1

(1) Proved reserves were evaluated based on the average first day of the month spot price for the preceding 12-month period of $96.94 per Bbl (WTI) and $3.67 per MMBtu (Henry Hub).

(2) Of the 155 MMBoe of combined extensions and discoveries, including assets sold, 5 MMBoe are in the Altamont area, 91 MMBoe are in the Eagle Ford Shale, and 51 MMBoe are in the Wolfcamp Shale. There were no extensions or discoveries in Brazil. Of the 155 MMBoe of extensions and discoveries, 117 MMBoe were liquids representing 75% of EP Energy's total extensions and discoveries.

(3) Equivalent volumes include an adjustment of 0.3 MMBoe to reflect an adjustment made to the prices used to calculate proved reserves.

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In accordance with SEC Regulation S-X, Rule 4-10 as amended, we use the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month preceding the 12-month period prior to the end of the reporting period. The first day 12-month average price used to estimate our proved reserves at December 31, 2015 was $50.28 per barrel of oil (WTI) and $2.59 per MMBtu for natural gas (Henry Hub).
All estimates of proved reserves are determined according to the rules prescribed by the SEC in existence at the time estimates were made. These rules require that the standard of "reasonable certainty" be applied to proved reserve estimates, which is defined as having a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as more technical and economic data becomes available, a positive or upward revision or no revision is much more likely than a negative or downward revision. Estimates are subject to revision based upon a number of factors, including many factors beyond our control such as reservoir performance, prices, economic conditions and government restrictions. In addition, as a result of drilling, testing and production subsequent to the date of an estimate; a revision of that estimate may be necessary. Reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.
Estimating quantities of proved oil and natural gas reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data. The accuracy of any reserve estimate is highly dependent on the quality of available data, the accuracy of the assumptions on which they are based upon economic factors, such as oil and natural gas prices, production costs, severance and excise taxes, capital expenditures, workover and remedial costs, and the assumed effects of governmental regulation. In addition, due to the lack of substantial, if any, production data, there are greater uncertainties in estimating proved undeveloped reserves, proved developed non-producing reserves and proved developed reserves that are early in their production life. As a result, our reserve estimates are inherently imprecise.
The meaningfulness of reserve estimates is highly dependent on the accuracy of the assumptions on which they were based. In general, the volume of production from oil and natural gas properties we own declines as reserves are depleted. Except to the extent we conduct successful exploration and development activities or acquire additional properties containing proved reserves, or both, our proved reserves will decline as reserves are produced. Subsequent to December 31, 2015, there have been no major discoveries, favorable or otherwise, on our proved reserves volumes that may be considered to have caused a significant change in our estimated proved reserves at December 31, 2015.

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Results of Operations. Results of operations for oil and natural gas producing activities for the years ended December 31, 2015, 2014 and 2013 (in millions):

	U.S.
2015 Consolidated:	
Net Revenues[1] — Sales to external customers	$1,241
Costs of products and services	(169)
Production costs[2]	(259)
Impairment charges	(4,297)
Depreciation, depletion and amortization[3]	(971)
Exploration and other expense	(20)
	(4,475)
Income tax benefit	1,607
Results of operations from producing activities	$(2,868)
2014 Consolidated:	
Net Revenues[1] — Sales to external customers	$2,099
Costs of products and services	(147)
Production costs[2]	(314)
Depreciation, depletion and amortization[3]	(863)
Exploration and other expense	(25)
	750
Income tax expense	(270)
Results of operations from producing activities	$480
2013 Consolidated:	
Net Revenues[1] — Sales to external customers	$1,628
Costs of products and services	(150)
Production costs[2]	(231)
Depreciation, depletion and amortization[3]	(573)
Exploration expense	(41)
	633
Income tax expense	(228)
Results of operations from producing activities	$405
2013 Unconsolidated Affiliate — Four Star[4]:	
Net Revenues — Sales to external customers	$69
Costs of products and services	(6)
Production costs[2]	(19)
Depreciation, depletion and amortization	(18)
	26
Income tax expense	(8)
Results of operations from producing activities	$18

(1) Excludes the effects of oil and natural gas derivative contracts.
(2) Production costs include lease operating costs and production related taxes, including ad valorem and severance taxes.
(3)

Includes accretion expense on asset retirement obligations of $3 million for both of the years ended December 31, 2015 and 2014 and $4 million for the year ended December 31, 2013.

(4) Results for 2013 are reported as of September 10, 2013 (the date the investment was sold). Results do not include amortization of $8 million for the year ended December 31, 2013 related to cost in excess of our equity interest in the underlying net assets of Four Star. In addition, in 2013 we recorded an impairment of $20 million, not included in the table above.

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Standardized Measure of Discounted Future Net Cash Flows. The standardized measure of discounted future net cash flows relating to our consolidated proved oil and natural gas reserves at December 31 is as follows (in millions):

			U.S.
2015 Consolidated:			
Future cash inflows[1]			$16,416
Future production costs			(6,903)
Future development costs			(4,668)
Future income tax expenses			(280)
Future net cash flows			4,565
10% annual discount for estimated timing of cash flows			(2,581)
Standardized measure of discounted future net cash flows			$1,984
2014 Consolidated:			
Future cash inflows[1]			$35,028
Future production costs			(9,628)
Future development costs			(6,488)
Future income tax expenses			(5,565)
Future net cash flows			13,347
10% annual discount for estimated timing of cash flows			(6,449)
Standardized measure of discounted future net cash flows			$6,898
	U.S.	Brazil	Worldwide
2013 Consolidated:			
Future cash inflows[1][2]	$32,577	$615	$33,192
Future production costs[2]	(9,083)	(365)	(9,448)
Future development costs	(6,789)	(71)	(6,860)
Future income tax expenses	(5,708)	(18)	(5,726)
Future net cash flows	10,997	161	11,158
10% annual discount for estimated timing of cash flows	(5,488)	(32)	(5,520)
Standardized measure of discounted future net cash flows	$5,509	$129	$5,638

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2015, 2014 and 2013. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

(2) For 2013, U.S. future cash inflows and U.S. production costs include an adjustment of $(1,142) million and $104 million, respectively, to reflect an adjustment made to the prices used to calculate the standardized measure of discounted future net cash flows at December 31, 2013. Due to this change, future income taxes and 10% annual discount for estimated timing of cash flows changed accordingly, for a total net adjustment to the originally reported standardized measure of discounted future net cash flows of $(341) million.

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Changes in Standardized Measure of Discounted Future Net Cash Flows. The following are the principal sources of change in our consolidated worldwide standardized measure of discounted future net cash flows (in millions):

	Year Ended December 31,[1]		
	2015	2014	2013
Consolidated:			
Sales and transfers of oil and natural gas produced net of production costs	$(982)	$(1,785)	$(1,493)
Net changes in prices and production costs	(7,085)	(762)	(745)
Extensions, discoveries and improved recovery, less related costs	145	1,728	2,626
Changes in estimated future development costs	997	63	(10)
Previously estimated development costs incurred during the period	835	1,192	679
Revision of previous quantity estimates	(1,008)	441	447
Accretion of discount	954	833	796
Net change in income taxes	2,428	384	(2,864)
Purchase of reserves in place	48	137	—
Sales of reserves in place	—	(229)	(886)
Change in production rates, timing and other	(1,246)	(613)	27
Net change	$(4,914)	$1,389	$(1,423)
Unconsolidated Affiliate — Four Star[2]:			
Sales and transfers of oil and natural gas produced net of production costs			$(41)
Net changes in prices and production costs			6
Extensions, discoveries and improved recovery, less related costs			—
Changes in estimated future development costs			25
Revision of previous quantity estimates			10
Accretion of discount			18
Net change in income taxes			68
Sales of reserves in place			(260)
Change in production rates, timing and other			38
Net change			$(136)
Representative NYMEX prices:[3]			
Oil (Bbl)	$50.28	$94.99	$96.94
Natural gas (MMBtu)	$2.59	$4.34	$3.67
Aggregate International prices:[3]			
Oil (Bbl)			$108.02
Natural gas (MMBtu)			$6.31

(1) This disclosure reflects changes in the standardized measure calculation excluding the effects of hedging activities.

(2) We sold our interest in Four Star in 2013.

(3) First day 12-month historical average U.S. price and an aggregate international price before price differentials and deducts. Price differentials and deducts were applied when the estimated future cash flows from estimated production from proved reserves were calculated.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2015, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Exchange Act is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect 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 our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of December 31, 2015. See Item 8, “Financial Statements and Supplementary Data” under Management’s Annual Report on Internal Control Over Financial Reporting.

Changes in Internal Control over Financial Reporting

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

ITEM 9B. OTHER INFORMATION

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

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

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2016 Annual Meeting of Stockholders.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

1. Financial statements: Refer to Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

2. Financial statement schedules: Refer to Item 8. “Financial Statements and Supplementary Data” in this Annual Report on Form 10-K.

	Page
3. and (b). Exhibits	101

The Exhibit Index, which follows the signature page to this report and is hereby incorporated herein by reference, sets forth a list of those exhibits filed herewith, and includes and identifies management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

The agreements included as exhibits to this report are intended to provide information regarding their terms and not to provide any other factual or disclosure information about us or the other parties to the agreements. The agreements may contain representations and warranties by the parties to the agreements, including us, solely for the benefit of the other parties to the applicable agreements and:

- should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate;
- may have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;
- may apply standards of materiality in a way that is different from what may be viewed as material to certain investors; and
- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

(c) Financial statement schedules

Financial statement schedules have been omitted because they are either not required or not applicable.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, EP Energy Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 19th day of February 2016.

EP ENERGY CORPORATION

By: /s/ Brent J. Smolik
Brent J. Smolik
President and Chief Executive Officer

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

Signature	Title	Date
/s/ Brent J. Smolik Brent J. Smolik	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	February 19, 2016
/s/ Dane E. Whitehead Dane E. Whitehead	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 19, 2016
/s/ Francis C. Olmsted III Francis C. Olmsted III	Vice President and Controller (Principal Accounting Officer)	February 19, 2016
/s/ Ralph Alexander Ralph Alexander	Director	February 19, 2016
/s/ Gregory A. Beard Gregory A. Beard	Director	February 19, 2016
/s/ Wilson B. Handler Wilson B. Handler	Director	February 19, 2016
/s/ John J. Hannan John J. Hannan	Director	February 19, 2016
/s/ Michael S. Helfer Michael S. Helfer	Director	February 19, 2016
/s/ Thomas R. Hix Thomas R. Hix	Director	February 19, 2016
/s/ Jaegu Nam Jaegu Nam	Director	February 19, 2016
/s/ Keith O. Rattie		

Keith O. Rattie	Director	February 19, 2016
/s/ Robert M. Tichio Robert M. Tichio	Director	February 19, 2016
/s/ Donald A. Wagner Donald A. Wagner	Director	February 19, 2016
/s/ Rakesh Wilson Rakesh Wilson	Director	February 19, 2016

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EP ENERGY CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed as part of this report. Exhibits filed with this Report are designated by "*". All exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement. Exhibits designated with a "†" indicate that a confidential treatment has been granted with respect to certain portions of the exhibit. Omitted portions have been filed separately with the SEC.

Exhibit No.	Exhibit Description
2.1	Purchase and Sale Agreement among EP Energy Corporation, EP Energy Holding Company and El Paso Brazil, L.L.C., as sellers, and EPE Acquisition, LLC, as purchaser, dated as of February 24, 2012 (Exhibit 2.1 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
2.2	Amendment No. 1 to Purchase and Sale Agreement, dated as of April 16, 2012, among EP Energy, L.L.C. (f/k/a EP Energy Corporation), EP Energy Holding Company, El Paso Brazil, L.L.C. and EPE Acquisition, LLC (Exhibit 2.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
2.3	Amendment No. 2 to Purchase and Sale Agreement, dated as of May 24, 2012, among EP Energy, L.L.C. (f/k/a EP Energy Corporation), EP Energy Holding Company, El Paso Brazil, L.L.C., EP Production International Cayman Company, EPE Acquisition, LLC and solely for purposes of Sections 2 and 5 thereunder, El Paso LLC (Exhibit 2.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
3.1	Second Amended and Restated Certificate of Incorporation of EP Energy Corporation (Exhibit 3.1 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
3.2	Amended and Restated Bylaws of EP Energy Corporation (Exhibit 3.2 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
4.1	Indenture, dated as of April 24, 2012, between EP Energy LLC (f/k/a Everest Acquisition LLC) and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 9.375% Senior Notes due 2020 (Exhibit 4.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.2	Indenture, dated as of August 13, 2012, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 7.750% Senior Notes due 2022 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.3	Indenture, dated as of May 28, 2015, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015).
4.4	Registration Rights Agreement, dated as of May 28, 2015, between EP Energy LLC, Everest Acquisition Finance Inc. and RBC Capital Markets, LLC, as representative of the several initial purchasers, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015).

4.5	Registration Rights Agreement, dated as of April 24, 2012, between EP Energy LLC (f/k/a Everest Acquisition LLC), Everest Acquisition Finance Inc. and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as representatives of the several initial purchasers, in respect of 9.375% Senior Notes due 2020 (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.6	Registration Rights Agreement, dated as of August 13, 2012, between EP Energy LLC, Everest Acquisition Finance Inc. and Citigroup Global Markets Inc., as representative of the several initial purchasers, in respect of 7.750% Senior Notes due 2022 (Exhibit 4.6 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
4.7	Registration Rights Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 4.8 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).

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Exhibit No.	Exhibit Description
10.1	Credit Agreement, dated as of May 24, 2012, by and among EPE Holdings, LLC, as Holdings, EP Energy LLC (f/k/a Everest Acquisition LLC), as the Borrower, the Lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Collateral Agent, and the other parties party thereto (Exhibit 10.1 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.2	Guarantee Agreement, dated as of May 24, 2012, by and among EPE Holdings LLC, the Domestic Subsidiaries of the Borrower signatory thereto and JPMorgan Chase Bank, N.A., as collateral agent for the Secured Parties referred to therein (Exhibit 10.2 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.3	Collateral Agreement, dated as of May 24, 2012, by and among EPE Holdings LLC, EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.4	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.4 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.5	Pledge Agreement, dated as of May 24, 2012, by and among El Paso Brazil, L.L.C., as Pledgor, and JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 10.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.6	Amendment, dated as of August 17, 2012, to the Credit Agreement, dated as of May 24, 2012, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.15 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.7	Second Amendment, dated as of March 27, 2013, to the Credit Agreement, dated as of May 24, 2012, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, filed with the SEC on May 9, 2013).
10.8	Third Amendment, dated as of October 27, 2014, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2013, filed with the SEC on April 30, 2015).
10.9	Fourth Amendment, dated as of April 6, 2014, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on April 6, 2015).
10.10	Consent and Agreement to Credit Agreement, dated as of June 7, 2013, among EPE Holdings LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.3 to EP Energy LLC's Quarterly Report on Form 10-Q for the quarterly

	period ended June 30, 2013, filed with the SEC on August 14, 2013).
10.11	Assumption and Ratification Agreement, dated as of April 30, 2014, entered into by EPE Acquisition, LLC, in favor of the Secured Parties (as defined in the Credit Agreement) (Exhibit 10.9 to Company's Annual Report on Form 10-K filed with the SEC on February 23, 2015).
10.12	Senior Lien Intercreditor Agreement, dated as of May 24, 2012, among JPMorgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent, Senior Secured Notes Collateral Agent and Applicable Second Lien Agent, Wilmington Trust, National Association, as Trustee under the Senior Secured Notes Indenture, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.6 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.13	Term Loan Agreement, dated as of April 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), as Borrower, the Lenders party thereto, Citibank, N.A., as Administrative Agent and Collateral Agent, and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as Co-Lead Arrangers (Exhibit 10.7 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.14	Guarantee Agreement, dated as of April 24, 2012, by and between Everest Acquisition Finance Inc., as Guarantor, and Citibank, N.A., as collateral agent for the Secured Parties referred to therein (Exhibit 10.8 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).

Exhibit No.	Exhibit Description
10.15	Collateral Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as Collateral Agent (Exhibit 10.9 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.16	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as Collateral Agent (Exhibit 10.10 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.17	Amendment No. 1, dated as of August 21, 2012, to the Term Loan Agreement, dated as of April 24, 2012, among EP Energy LLC, the lenders party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.16 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.18	Joinder Agreement, dated as of August 21, 2012, among Citibank, N.A., as Additional Tranche B-1 Lender, EP Energy LLC and Citibank, N.A., as administrative agent (Exhibit 10.17 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.19	Incremental Facility Agreement, dated October 31, 2012, to the Term Loan Agreement, dated as of April 24, 2012 and amended by that certain Amendment No. 1 dated as of August 21, 2012, among EP Energy LLC, the lenders from time to time party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on October 31, 2012).
10.20	Reaffirmation Agreement, dated as of October 31, 2012, among EP Energy LLC, each Subsidiary Party party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K, filed with the SEC on October 31, 2012).
10.21	Amendment No. 2, dated as of May 2, 2013, to the Term Loan Agreement, dated as of April 24, 2012, among EP Energy LLC, the lenders party thereto and Citibank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on May 28, 2013).
10.22	Joinder Agreement, dated as of May 2, 2013, among Citibank, N.A., as Additional Tranche B-1 Lender, EP Energy LLC and Citibank, N.A., as administrative agent (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on May 28, 2013).
10.23	Pari Passu Intercreditor Agreement, dated as of May 24, 2012, among Citibank, N.A., as Second Lien Agent, Citibank, N.A., as Authorized Representative for the Term Loan Agreement, Wilmington Trust, National Association, as the Initial Other Authorized Representative and each additional Authorized Representative from time to time party hereto (Exhibit 10.12 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.24	Amended and Restated Management Fee Agreement, dated as of December 20, 2013, among EP Energy Corporation, EP Energy Global LLC, EPE Acquisition, LLC, Apollo Management VII, L.P., Apollo Commodities Management, L.P., With Respect to Series I, Riverstone V Everest Holdings, L.P., Access Industries, Inc. and Korea National Oil Corporation (Exhibit 10.23 to Amendment No. 4 to the

	Company's Registration Statement on Form S-1, filed with the SEC on January 6, 2014).
10.25+	Employment Agreement dated May 24, 2012 for Clayton A. Carrell (Exhibit 10.18 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.26+	Employment Agreement dated May 24, 2012 for Brent J. Smolik (Exhibit 10.20 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.27+	Employment Agreement dated May 24, 2012 for Dane E. Whitehead (Exhibit 10.21 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.28+	Employment Agreement dated May 24, 2012 for Marguerite N. Woung-Chapman (Exhibit 10.22 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.29+	Employment Agreement dated May 24, 2012 for Joan M. Gallagher (Exhibit 10.30 to Company's Annual Report on Form 10-K filed with the SEC on February 23, 2015).
10.30+	Senior Executive Survivor Benefit Plan adopted as of May 24, 2012 (Exhibit 10.23 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.31+	2012 Omnibus Incentive Plan (Exhibit 10.24 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.32+	Management Incentive Plan Agreement, dated as of August 30, 2013, between EP Energy Corporation and EPE Employee Holdings, LLC (Exhibit 10.31 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†

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Exhibit No.	Exhibit Description
10.33+	Form of EPE Employee Holdings, LLC Management Incentive Unit Agreement (Exhibit 10.26 to EP Energy LLC's Registration Statement on Form S-4 filed with the SEC on September 11, 2012).
10.34+	Form of Notice to MIPs Holders regarding Corporate Reorganization (Exhibit 10.33 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).
10.35+	Third Amended and Restated Limited Liability Company Agreement of EPE Employee Holdings, LLC dated as of August 30, 2013 (Exhibit 10.34 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†
10.36+	Third Amended and Restated Limited Liability Company Agreement of EPE Management Investors, LLC dated as of August 30, 2013 (Exhibit 10.35 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on November 1, 2013).†
10.37+	Subscription Agreement, dated as of August 30, 2013, between EP Energy Corporation and EPE Management Investors, LLC (Exhibit 10.36 to the Company's Registration Statement on Form S-1, filed with the SEC on September 4, 2013).
10.38+	Form of EP Energy Employee Holdings II, LLC Class B Incentive Pool Program Award Agreement (Exhibit 10.37 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.39+	EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on January 23, 2014).
10.40+	Form of Notice Stock Option Grant and Stock Option Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.39 to Company's Annual Report on Form 10-K filed with the SEC on February 27, 2014).
10.41+	Form of Notice Restricted Stock Grant and Restricted Stock Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.40 to Company's Annual Report on Form 10-K filed with the SEC on February 27, 2014).
10.42+*	Form of Performance Unit Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan.
10.43	Stockholders Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 10.39 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.44	Addendum Agreement, dated as of September 18, 2013, to the Stockholders Agreement, between EP Energy Corporation and EP Energy Employee Holdings II, LLC (Exhibit 10.40 to Amendment No. 1 to the Company's Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.45	Form of Director and Officer Indemnification Agreement between EP Energy Corporation and each of the officers and directors thereof (Exhibit 10.41 to Amendment No. 4 to the Company's Registration Statement on Form S-1, filed with the SEC on January 6, 2014).

12.1*	Ratio of Earnings to Fixed Charges
21.1*	Subsidiaries of EP Energy Corporation.
23.1*	Consent of Ernst & Young LLP, an independent registered public accounting firm.
23.2*	Consent of Ryder Scott Company, L.P.
31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Ryder Scott Company, L.P. reserve audit report for EP Energy Corporation as of December 31, 2015.

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Exhibit No.	Exhibit Description
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Schema Document.
101.CAL*	XBRL Calculation Linkbase Document.
101.DEF*	XBRL Definition Linkbase Document.
101.LAB*	XBRL Labels Linkbase Document.
101.PRE*	XBRL Presentation Linkbase Document.