EP Energy Corp
Form 10-K
February 23, 2015
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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, 2014

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. o

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 o
Non-accelerated filer x (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, 2014, was $729,098,077 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, 2015: 244,781,024

Class B Common Stock, par value $0.01 per share. Shares outstanding as of February 10, 2015: 817,560

Documents Incorporated by Reference: Portions of the definitive proxy statement for the 2015 Annual Meeting of Stockholders of EP Energy Corporation, which will be held on May 7, 2015, are incorporated by reference into Part III of this Annual Report on Form 10-K.

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EP ENERGY CORPORATION

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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 our 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-look 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 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 risk of our lenders, trading counterparties, customers, vendors and suppliers;
- 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 18 through 35 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). Hereinafter, this acquisition is referred to as the Acquisition with EP Energy Corporation referred to as the successor and the acquired entities referred to as the predecessor for financial accounting and reporting purposes.

We operate through a large and diverse base of producing assets located predominantly in four operating 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 operating areas, we have identified approximately 5,670 drilling locations (including 979 drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2014, of which approximately 92% are oil wells). At 2014 activity levels, this represents approximately 21 years of drilling inventory (more than 30 years of drilling inventory at 2015 activity levels). As of December 31, 2014, we had proved reserves of 622.2 MMBoe (52% oil and 67% liquids) and for the year ended December 31, 2014, we had average production of 97,734 Boe/d (56% oil and 68% liquids).

Each of our operating areas is characterized by a favorable operating environment, a long-lived reserve base and high drilling success rates. We have established significant contiguous leasehold positions in each area, representing approximately 477,000 net (647,000 gross) acres in total. Beginning in 2012, our capital programs have focused predominantly on the Eagle Ford Shale, the Wolfcamp Shale and Altamont, three of the premier unconventional oil plays in the United States, resulting in oil reserve and production growth of 10% and 51%, respectively, from December 31, 2013 to December 31, 2014.

During 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 $152 million. The acquisition represents 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) for approximately $150 million of cash proceeds, with the buyer also assuming a transportation commitment of approximately $20 million, (ii) our Brazilian operations and (iii) certain non-core acreage in Atascosa County in Eagle Ford for approximately $28 million of cash proceeds.

Prior to 2014, we divested of non-core domestic natural gas assets and an equity investment for a total consideration of approximately $1.5 billion. As a result of these asset sales, we became a higher-growth, 100% onshore, oil-weighted company with a large inventory of low-risk drilling locations. We intend to continue to principally focus on the development of our oil-weighted assets, but depending on commodity prices and rates of return our Haynesville Shale position gives us the flexibility to allocate capital to this natural gas asset.

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The following table provides a summary of our oil, natural gas and NGLs reserves as of December 31, 2014 and production data for the year ended December 31, 2014 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)
Operating Areas							
Eagle Ford Shale	183.1	65.5	398.0	314.9	79%	32%	50.9
Wolfcamp Shale	53.9	28.7	158.2	109.0	76%	47%	15.3
Altamont	83.8		180.4	113.9	74%	49%	15.5
Haynesville Shale			506.1	84.3	%	36%	15.9
Total Areas	**320.8**	**94.2**	**1,242.7**	**622.1**	**67%**	**38%**	**97.6**
Other (2)			0.3	0.1	%	100%	0.1
Total	**320.8**	**94.2**	**1,243.0**	**622.2**	**67%**	**38%**	**97.7**

(1) Proved reserves were evaluated using first day 12-month prices of $94.99 per barrel of oil (WTI) and $4.34 per MMBtu of natural gas (Henry Hub).

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

Approximately 223 MMBoe, or 36%, of our total proved reserves are proved developed producing assets, which generated an average production of 97.7 MBoe/d in 2014 from approximately 1,325 wells. As of December 31, 2014, we had approximately 321 MMBbls of proved oil reserves, 94 MMBbls of proved NGLs reserves and 1,243 Bcf of proved natural gas reserves in the United States, representing 52%, 15% and 33%, respectively, of our total proved reserves. For the year ended December 31, 2014, 68% of our production and 86% of our revenues (excluding realized and unrealized gains on financial derivatives) were related to oil and NGLs versus 53% and 82% in 2013, respectively, and over that same period and on that same basis, our oil production has grown by approximately 51%. Based on our announced guidance, a substantial portion of our 2015 capital expenditures will be allocated to our oil programs.

We operate 85% of our producing wells and have operational control over approximately 97% of our operating area drilling inventory as of December 31, 2014. 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. 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 2014, we drilled 273 wells with a success rate of 100%, adding approximately 101 MMBoe of proved reserves (77% of which were liquids), excluding divested assets. Our reserve replacement cost as of December 31, 2014 was $16.93 per Boe. See Part II, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Reserve Replacement Ratio/Reserve Replacement Costs for further discussion of these metrics.

Our Properties and Operating Areas

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. As of December 31, 2014, we had 81,753 net (88,890 gross) acres in the Eagle Ford, in which we have identified 872 drilling locations.

During 2014, we invested $1,087 million in capital expenditures in our Eagle Ford Shale and operated an average of 5.5 drilling rigs. As of December 31, 2014, we had 402 net producing wells (399 net operated wells) and are currently running five rigs. For the year ended December 31, 2014, our average net daily production was 50,916 Boe/d, representing growth of 39% over the same period in 2013. For the year ended December 31, 2014 our average cost per gross well was $7.2 million ($6.8 million per net well).

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. 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.

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Our large, contiguous acreage positions are characterized by stacked pay zones, including the Wolfcamp A, B, and C, 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, 2014, we have 179,780 net (181,487 gross) acres in the Wolfcamp, in which we have identified approximately 3,300 drilling locations in the Wolfcamp A, B, and C. In the second half of 2014, we initiated drilling in the Wolfcamp A.

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 2014, we invested $822 million in capital expenditures (including $158 million of acquisition capital) in our Wolfcamp Shale and operated an average of 3.5 drilling rigs. As of December 31, 2014, we had 201 net operated producing wells. We are currently running two rigs. For the year ended December 31, 2014, our average net daily production was 15,256 Boe/d, representing growth of 178% over 2013. For the year ended December 31, 2014, our average cost per gross well was $6.2 million ($6.2 million per net well).

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 177,119 net (319,600 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, 2014, we have identified 1,304 drilling locations (1,295 vertical and 9 horizontal). The industry has piloted 80-acre vertical downspacing, and in November 2014 the Utah Board of Oil, Gas and Mining approved 80-acre well density on approximately 50,000 acres of our Altamont net acreage. Industry activity has also focused on horizontal drilling in the Wasatch and Green River formations testing tight carbonate and sand intervals. Due to the largely held-by-production nature of our acreage position, if these programs are successful, it will result in additional vertical and horizontal drilling opportunities that could be added to our inventory of drilling locations.

During 2014, we invested $283 million in capital expenditures in the Altamont Field, operated an average of 3.0 drilling rigs, and drilled 47 operated gross wells. As of December 31, 2014, we had 365 net producing wells (356 net operated wells). We are currently running two rigs after dropping the third rig in January 2015. For the year ended December 31, 2014, our average net daily production was 15,468 Boe/d, representing growth of 30% over 2013. For the year ended December 31, 2014 our average cost per gross well was $5.2 million ($4.4 million per net well).

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 38,224 net (57,502 gross) acres in this area. As of December 31, 2014, we have identified 197 drilling locations.

During 2014, we invested $8 million in capital expenditures in our Haynesville Shale program. For the year ended December 31, 2014, our average net daily production was 96 MMcfe/d. As of December 31, 2014, we had 106 net producing wells. In 2012, we suspended investment in the Haynesville program due to low natural gas prices, but have announced our intent to invest in this area in 2015 based on the current commodity price environment and expected rates of return. Our acreage in the Haynesville Shale is 100% held-by-production, giving us the flexibility to allocate capital to this natural gas asset.

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The following table provides a summary of acreage and inventory data as of December 31, 2014:

[redacted]							
Operating Areas							
[redacted]							
Wolfcamp Shale	181,487	179,780	3,300	90	36.7	97%	73%
[redacted]							
Wolfcamp B			1,019			97%	73%
[redacted]							
Altamont	319,600	177,119	1,304	47	27.7	75%	62%
[redacted]							
Horizontal			9			62%	48%
[redacted]							
Holly			116			77%	62%
[redacted]							
Total Operating Areas	**647,479**	**476,876**	**5,673**	**273**	**20.8**	**90%**	**69%**

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(1) Our inventory as of December 31, 2014 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 2014.

(3) Calculated as Drilling Locations divided by 2014 Drilling Locations. At 2015 activity levels, inventory is approximately 30 years.

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, 2014, 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, 2014.

	Net Proved Reserves(1)				
	Oil (MMBbls)	**NGLs (MMBbls)**	**Natural Gas (Bcf)**	**Total (MMBoe)**	**Percent (%)**
Reserves by Classification					
Proved Developed					
Operating Areas					
Eagle Ford Shale	64.1	18.2	111.6	100.9	16%
Wolfcamp Shale	23.8	14.2	78.5	51.1	8%
Altamont	40.5		90.9	55.7	9%
Haynesville Shale			182.3	30.3	5%
Total Operating Areas	128.4	32.4	463.3	238.0	38%
Other(2)			0.3	0.1	%
Total Proved Developed(3)	128.4	32.4	463.6	238.1	38%
Proved Undeveloped					
Operating Areas					
Eagle Ford Shale	119.0	47.3	286.4	214.0	34%
Wolfcamp Shale	30.1	14.5	79.7	57.9	9%
Altamont	43.3		89.5	58.2	10%
Haynesville Shale			323.8	54.0	9%
Total Operating Areas	192.4	61.8	779.4	384.1	62%
Other(2)					%
Total Proved Undeveloped	192.4	61.8	779.4	384.1	62%
Total Proved Reserves	320.8	94.2	1,243.0	622.2	100%

(1) Proved reserves were evaluated using the first day 12-month average prices of $94.99 per barrel of oil (WTI) and $4.34 per MMBtu of natural gas (Henry Hub).

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

(3) Includes 223 MMBoe of proved developed producing reserves representing 36% of total net proved reserves and 15 MMBoe of proved developed non-producing reserves representing 2% of total net proved reserves at December 31, 2014.

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, 2014.

	Net Proved Reserves (MMBoe)
As Reported	622.2
10 percent increase in commodity prices(1)	624.7
10 percent decrease in commodity prices(1)	618.8

(1) Based on the first day 12-month average prices of $94.99 per barrel of oil (WTI) and $4.34 per MMBtu of natural gas (Henry Hub) used to determine net proved reserves at December 31, 2014.

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.

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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 as well as our Marketing and Commercial groups. He also oversees the reserve reporting and technical/business excellence groups. He has more than 25 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, 2014. In connection with its audit, Ryder Scott reviewed 94% (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, 91% 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, 2014 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 11 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, 2014, we have 384 MMBoe of PUD reserves and 979 PUD locations within our operating areas, all of which are scheduled to be developed or drilled within five years of their initial recording. 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 operating areas, including field tests that demonstrate consistent and repeatable results within the formation being evaluated.

We assess our PUD reserves on a quarterly basis. During 2014, we increased our PUD reserves by a net 19 MMBoe compared to December 31, 2013, including the addition of 75 MMBoe of PUD reserves primarily from our drilling activities in the Eagle Ford Shale and Altamont; positive revisions of 26 MMBoe primarily due to the recovery of certain natural gas PUD reserves; acquisition of 3 MMBoe of PUD reserves in our Wolfcamp Shale; 75 MMBoe of PUD reserves transferred to proved developed reserves; 8 MMBoe related to our divestitures; and 2 MMBoe of PUD reserves transferred to probable reserves due to long rang plan capital reductions resulting from changes in economic outlook.

We spent approximately $1,192 million, $679 million and $587 million during 2014, 2013 and 2012, respectively, to convert approximately 20% or 75 MMBoe, 12% or 39 MMBoe and 10% or 32 MMBoe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2014 internal reserve report, the amounts estimated to be spent in 2015, 2016 and 2017 to develop our PUD reserves are $1,157 million, $1,378 million and $1,390 million, respectively. The upward trend in the amounts estimated to be spent to develop our PUD reserves is a result of our focus on developing our oil programs. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, service costs and commodity prices.

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The following table summarizes our changes in PUDs for the years ended December 31, 2013 and December 31, 2014, respectively (in MMBoe):

Balance, December 31, 2012	315
Extensions and discoveries	109
Revisions of previous estimates(1)	6
Transfers to proved developed	(39)
Divestitures	(26)
Balance, December 31, 2013	**365**
Purchase of minerals in place	3
Extensions and discoveries(2)	75
Revisions of previous estimates(3)	26
Transfers to proved developed	(75)
Divestitures	(8)
Other(4)	(2)
Balance, December 31, 2014	**384**

(1) Revisions to previous estimates during 2013 are primarily due to improved performance and ownership positions.

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

(3) Revisions to previous estimates during 2014 are primarily due to increased natural gas prices.

(4) Represents PUDs reclassified as probable reserves due to long-range plan capital reductions resulting from changes in economic outlook.

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Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2014, (ii) our interest in oil and natural gas wells at December 31, 2014 and (iii) our exploratory and development wells drilled during the years 2012 through 2014. 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						
Operating Areas						
Eagle Ford Shale	28,325	26,043	60,565	55,710	88,890	81,753
Wolfcamp Shale	14,129	14,021	167,358	165,759	181,487	179,780
Altamont	95,410	75,613	224,190	101,506	319,600	177,119
Haynesville Shale	14,948	10,597	42,554	27,627	57,502	38,224
Total Operating Areas	152,812	126,274	494,667	350,602	647,479	476,876
Other	107,304	10,424	281,839	170,216	389,143	180,640
Total Acreage	260,116	136,698	776,506	520,818	1,036,622	657,516

(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 primarily in Utah (55%), Texas (33%) and Louisiana (8%). Our net undeveloped acreage is concentrated primarily in Texas (44%), Utah (20%), Michigan (10%), Wyoming (9%), West Virginia (8%), Louisiana (6%) and Colorado (3%). Approximately 5%, 9% and 19% of our net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2015, 2016 and 2017, respectively. We employ various techniques to manage the expiration of leases, including drilling the acreage ourselves prior to lease expiration, entering into farm-out agreements with other operators or extending lease terms.

	Oil		**Natural Gas**		**Total**		**Wells Being Drilled at December 31, 2014(1)**	
	Gross(2)	**Net(3)**	**Gross(2)**	**Net(3)**	**Gross(2)**	**Net(3)(4)**	**Gross(2)**	**Net(3)**
Productive Wells								
Eagle Ford Shale	434	399	3	3	437	402	38	37
Wolfcamp Shale	207	204			207	204	26	26
Altamont	479	364	3	1	482	365	5	1
Haynesville Shale			203	106	203	106		
Total Productive Wells	1,120	967	209	110	1,329	1,077	69	64

(1) Comprised of wells that were spud as of December 31, 2014 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, 2014, we operated 1,055 of the 1,077 net productive wells.

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	Net Exploratory(1)			Net Development(1)		
	2014	2013	2012	2014	2013	2012
Wells Drilled						
Operating Areas						
Productive	5	8	13	257	216	116
Dry			1		2	2
Total Operating Areas	5	8	14	257	218	118
Divested Assets(2)						
Productive			7			16
Dry						1
Total Divested Assets			7			17
Total						
Productive	5	8	20	257	216	132
Dry			1		2	3
Total Wells Drilled	5	8	21	257	218	135

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

(2) Wells of divested assets in 2012 include those for our South Louisiana Wilcox and Arklatex Tight Gas areas sold in 2014, our CBM, South Texas and Arklatex assets, each sold in 2013 and of our Gulf of Mexico assets sold in 2012.

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 operating 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:

	2014	2013	2012
Volumes:			
Net Production Volumes			
Operating Areas			
Oil (MBbls)	19,979	13,230	8,277
Natural Gas (MMcf)	69,177	83,606	122,254
NGLs (MBbls)	4,109	2,424	1,056
Total Operating Areas (MBoe)	35,617	29,588	29,709
Other			
Oil (MBbls)	6	5	24
Natural Gas (MMcf)	257	210	2,457
NGLs (MBbls)	7	10	42
Total Other (MBoe)	56	50	476
Total Operating and Other Areas			
Oil (MBbls)	19,985	13,235	8,301
Natural Gas (MMcf)	69,434	83,816	124,711
NGLs (MBbls)	4,116	2,434	1,098
Total Operating and Other Areas (MBoe)	35,673	29,638	30,185
Divested Assets(1)			
Oil (MBbls)		197	743
Natural Gas (MMcf)		10,050	59,189
NGLs (MBbls)		327	887
Total (MBoe)		2,199	11,494
Total Net Production Volumes			
Oil (MBbls)	19,985	13,432	9,044
Natural Gas (MMcf)	69,434	93,866	183,900
NGLs (MBbls)	4,116	2,761	1,985
Total Equivalent Volumes (MBoe)	35,673	31,837	41,679
MBoe/d(2)	*97.7*	*87.2*	*113.9*

(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. Volumes in 2012 include 282 MBbls of oil, 15,552 MMcf of natural gas, 478 MBbls of NGLs and 3,352 MBoe related to Four Star. Remaining volumes include volumes from our South Louisiana Wilcox and Arklatex Tight Gas areas sold in 2014, our CBM, South Texas, and the majority of our Arklatex assets, all of which were in sold in 2013, and our Gulf of Mexico assets, which were sold in 2012. For periods after May 24, 2012, our South Louisiana Wilcox, CBM, South Texas, and Arklatex assets are treated as discontinued operations and accordingly volumes relating to those assets are excluded from all financial and non-financial metrics. In addition, our Brazilian operations are treated as discontinued operations in all periods, and accordingly volumes are excluded from all financial and non-financial metrics for both predecessor and successor periods.

(2) The years ended December 31, 2013 and 2012 include 6.0 Mboe/d and 9.2 Mboe/d, respectively, from Four Star.

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	2014	2013	2012
Operating Area Net Production Volumes			
Eagle Ford Shale			
Oil (MBbls)	12,698	8,763	5,023
Natural Gas (MMcf)	18,215	14,857	8,425
NGLs (MBbls)	2,851	2,133	936
Total Eagle Ford Shale (MBoe)	18,585	13,372	7,364
Wolfcamp Shale			
Oil (MBbls)	3,073	1,306	489
Natural Gas (MMcf)	7,551	2,483	763
NGLs (MBbls)	1,237	280	116
Total Wolfcamp Shale (MBoe)	5,568	2,000	734
Altamont			
Oil (MBbls)	4,208	3,161	2,765
Natural Gas (MMcf)	8,504	6,931	6,632
NGLs (MBbls)	21	11	4
Total Altamont (MBoe)	5,646	4,327	3,876
Haynesville Shale			
Oil (MBbls)			
Natural Gas (MMcf)	34,907	59,335	106,434
NGLs (MBbls)			
Total Haynesville Shale (MBoe)	5,818	9,889	17,736

	2014	2013	2012
Prices and Costs per Unit:(1)			
Oil Average Realized Sales Price ($/Bbl)			
Physical Sales	$ 85.31	$ 94.75	$ 92.28
Including Financial Derivatives(2)	$ 88.77	$ 97.56	$ 97.01
Natural Gas Average Realized Sales Price ($/Mcf)			
Physical Sales	$ 3.76	$ 3.28	$ 2.64
Including Financial Derivatives(2)	$ 3.34	$ 2.97	$ 4.66
NGLs Average Realized Sales Price ($/Bbl)			
Physical Sales	$ 26.73	$ 30.58	$ 37.70
Including Financial Derivatives(2)	$ 27.78	$	$

(1) Prices and costs per unit are calculated excluding volumes related to Four Star.

(2) Amounts reflect settlements on financial derivatives, including cash premiums. For the years ended December 31, 2014, 2013 and 2012, we received $1 million, $9 million and paid $3 million of cash premiums, respectively.

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	2014	2013	2012
Average Transportation Costs			
Operating Areas			
Oil ($/Bbl)	$ 1.65	$ 2.01	$ 2.09
Natural Gas ($/Mcf)	$ 0.65	$ 0.52	$ 0.40
NGLs ($/Bbl)	$ 5.42	$ 6.08	$ 2.93
Other			
Oil ($/Bbl)	$ 0.85	$ 0.83	$ 0.28
Natural Gas ($/Mcf)	$ 1.31	$ 0.01	$ 0.51
NGLs ($/Bbl)	$ 5.37	$ 3.88	$ 9.48
Divested Assets(1)			
Oil ($/Bbl)	$	$	$ 0.04
Natural Gas ($/Mcf)	$	$	$ 0.42
NGLs ($/Bbl)	$	$	$ 7.30
Consolidated			
Oil ($/Bbl)	$ 1.65	$ 2.01	$ 1.91
Natural Gas ($/Mcf)	$ 0.65	$ 0.52	$ 0.41
NGLs ($/Bbl)	$ 5.42	$ 6.07	$ 4.29
Average Lease Operating Expenses ($/Boe)			
Operating Areas	$ 5.41	$ 5.04	$ 3.26
Divested Assets(1)	$	$	$ 4.58
Total Consolidated	$ 5.40	$ 4.98	$ 3.56
Average Production Taxes ($/Boe)			
Operating Areas	$ 3.40	$ 2.84	$ 1.93
Divested Assets(1)	$	$	$ 1.57
Total Consolidated	$ 3.39	$ 2.84	$ 1.84

(1) Divested assets in 2012 represent activity prior to May 24, 2012 and include our South Louisiana Wilcox and Arklatex Tight Gas assets sold in 2014, our CBM, South Texas and Arklatex assets sold in 2013 and our Gulf of Mexico assets sold in 2012.

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 Cost 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 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 credit-worthy counterparties, as is customary in the industry. For the year ended December 31, 2014, four purchasers accounted for approximately 80% of our oil revenues: Plains Marketing LP, Chevron Corporation, Flint Hills Resources, LP, an affiliate of Koch Industries, and Shell Trading U.S. Co., an affiliate of Shell Oil Company. As oil volumes grow, 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 operating areas, we maintain adequate gathering, treating, processing and transportation capacity, as well as downstream sales arrangements, to accommodate our growing production volumes.

In our Eagle Ford Shale operating area, we are connected to the Camino Real Gathering System and to the Frio LaSalle Pipeline system. The vast majority of our oil production flows on the Camino Real oil gathering system, 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 58% during December 2014. 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 recently-added 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 expect our utilization rate on the Camino Real oil gathering system to increase as new wells are connected. We currently market our oil either at the Storey Terminal 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

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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 additional 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 57% during December 2014, and we have additional capacity available as needed. Our capacity utilization will increase as additional wells are connected to the system. 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 operating 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 operating 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 pipeline at Owens Station in Reagan County, Texas and to the Centurion Cline Shale Pipeline at Barnhart in Irion 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. During the fourth quarter of 2014, we entered into a new two-year oil sale agreement on a portion of our Wolfcamp volumes with pricing of WTI less a fixed amount, reducing our risk in the fluctuations in the Midland-Cushing differential. With new Permian Basin takeaway pipelines coming online in 2015, we anticipate no limitations moving physical crude oil to market and expect regional pricing to remain correlated with NYMEX/WTI.

In our Altamont operating 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. In addition, we have entered into a variety of crude-by-rail solutions to expand the market for Altamont wax crude beyond Salt Lake City. We anticipate that planned expansions of Salt Lake City refineries and expanded rail capacity will keep pace with basin-wide production growth, and we 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 our Haynesville Shale operating 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 245 MMcf/d of firm capacity on these pipelines, of which we used an average of 46% during December 2014. Capacity obligations will drop 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 an active risk management program. We enter into an array of financial derivatives contracts on our oil and natural gas 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 sophisticated, disciplined risk management program that utilizes rigorous risk control processes and leverages the extensive 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 .

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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 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 or acquire additional reserves at costs that yield acceptable returns on the capital invested.

Use of 3-D Seismic Data

We have an inventory of approximately 2,200 square miles of 3-D seismic data. We have 1,092 square miles of 3-D seismic data in our four operating areas which provides approximately 39% 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, drilling operations, production or the delay or prevention of future offshore lease sales. In addition, we maintain insurance to limit exposure to sudden and accidental pollution liability exposures.

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 operating areas and our proved undeveloped oil and natural gas reserves will be developed using hydraulic fracturing. For the year ended December 31, 2014, we incurred costs of approximately $556 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 also 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 fracture 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.

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- 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, many of which we own and 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 8.

Employees

As of February 16, 2015, we had 748 full-time employees in the United States.

Executive Officers of the Registrant

Our executive officers as of February 16, 2015, are listed below.

Name	Office	Age
Brent J. Smolik	President, Chief Executive Officer and Chairman of the Board	53
Clayton A. Carrell	Executive Vice President and Chief Operating Office	49
Joan M. Gallagher	Senior Vice President, Human Resources and Administrative Services	51
Dane E. Whitehead	Executive Vice President and Chief Financial Officer	53
Marguerite N. Woung-Chapman	Senior Vice President, General Counsel and Corporate Secretary	49

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 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 also serves on the board of the American Exploration and Production Council. 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, is a member of the Society of Petroleum Engineers and a Board Member of the US Oil & Gas Association. 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 supply and demand for oil, natural gas and NGLs could be negatively impacted by many factors outside of our control, which could have a material adverse effect on our business, results of operations and financial condition.

Our success depends on the domestic and worldwide supply and demand for oil, natural gas and NGLs which will depend on many factors outside of our control, including:

- the oversupply of oil, natural gas and/or NGLs;
- adverse changes in geopolitical factors, including the ability of the Organization of Petroleum Exporting Countries (OPEC) to agree upon and maintain certain production levels, political unrest and changes in foreign governments in energy producing regions of the world and unexpected wars, terrorist activities and other acts of aggression;
- adverse changes in global, geopolitical and economic conditions, including changes that negatively impact general demand for oil and its refined products; power generation and industrial loads for natural gas; and petrochemical, refining and heating demand for NGLs;
- perceptions of customers on the availability and price volatility of our products, particularly customers perceptions on the volatility of oil and natural gas prices over the longer term;
- increased prices of oil, natural gas or NGLs that could negatively impact the demand for these products;
- adverse changes in domestic regulations that could impact the supply or demand for oil, natural gas and NGLs, including potential restrictive regulations associated with hydraulic fracturing operations;
- increased costs to explore for, develop and produce oil, natural gas or NGLs, including increases in oil field service costs;

- technological advancements that may drive further increases in production from oil and natural gas shales;

- the need of many producers to drill to maintain leasehold positions regardless of current commodity prices;

- the relative growth of natural gas-fired power generation, including the speed and level of existing coal-fired generation that is replaced by natural gas-fired generation, which could be offset by the growth of various renewable energy sources;

- adoption of various energy efficiency and conservation measures;

- the impact of weather on demand for oil, natural gas and/or NGLs; and

- competition from imported and potentially exported liquefied natural gas (LNG), Canadian supplies and alternate fuels.

The prices for oil, natural gas and NGLs are highly volatile and could be negatively impacted by many factors outside of our control, which could have a material adverse effect on 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, the lowest price since 2009. There is a risk that commodity prices could remain depressed for sustained periods. Except to the extent of our risk mitigation and hedging strategies, we can be impacted by short-term changes in commodity prices. We would also be negatively impacted in the long-term by any sustained depression in prices for oil, natural gas or NGLs, including reductions in our drilling opportunities. The prices for oil, natural gas and NGLs are subject to a variety of additional factors that are outside of our control, which include, among others:

- changes in regional, domestic and international supply of, and demand for, oil, natural gas and NGLs;

- natural gas inventory levels in the United States;

- political and economic conditions domestically and in other oil and natural gas producing countries, including, among others, countries in the Middle East, Africa and South America;

- actions of OPEC and other state-controlled oil companies relating to oil price and production controls;

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- volatile trading patterns in capital and commodity-futures markets;
- changes in the costs of exploring for, developing, producing, transporting, processing and marketing oil, natural gas and NGLs;
- weather conditions and weather patterns;
- technological advances affecting energy consumption and energy supply;
- domestic governmental regulations and taxes, including administrative and/or agency actions;
- availability, proximity and cost of commodity processing, gathering and transportation and refining capacity;
- the price and availability of supplies of alternative energy sources;
- the effect of LNG deliveries to or the ability to export LNG from the United States;
- the strengthening and weakening of the U.S. dollar relative to other currencies; and
- variations between product prices at sales points and applicable index prices.

In addition to negatively impacting our cash flows, prolonged or substantial declines in commodity prices could negatively impact our proved oil and natural gas reserves and impact the amount of oil and natural gas that we can produce economically in the future. A decrease in production could result in a shortfall in our expected cash flows and require us to reduce our capital spending or borrow funds to cover any such shortfall. Prices also affect our cash flow available for capital expenditures and 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 based on pricing models determined by the lenders at such time. Declines in oil, natural gas and NGLs prices may adversely impact the value of our proved reserves and, in turn, the bank pricing used by our lenders to determine our borrowing base. Any of these factors could negatively impact our liquidity, our ability to replace our production and our future rate of growth. On the other hand, increases in these commodity prices may be offset by increases in drilling costs, production taxes and lease operating costs that typically result from any increase in such commodity prices. Any of these outcomes could have a material adverse effect on our business, results of operations and financial condition.

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 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 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.

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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 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 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. 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.

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.

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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. The risk that a counterparty may default on its obligations is heightened by the recent decline in commodity prices and financial sector crisis and losses incurred by many banks and other financial institutions, including our counterparties or their affiliates. These losses may affect the ability of the counterparties to meet their obligations to us on hedge transactions, which would 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 requires the CFTC and the prudential banking regulators to establish 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), certain market participants, including most if not all of our counterparties, will also be required to clear many of their swap transactions with entities that do not satisfy the End-User Exception and 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. 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; 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. Because the margin regulations for uncleared swaps have not been adopted, we do not yet know whether our counterparties will be required to collect liquid margin from us for those swaps.

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 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. Comments on the proposed rule were due on February 10, 2014. We cannot predict whether or when the proposed rule will be adopted or the effect of the proposed 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

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lower commodity prices. Any of these consequences could have a material and adverse effect on our business, financial condition and results of operations.

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 2014, we spent total capital including acquisitions of $2.2 billion. We have established a capital budget for 2015 of approximately $1.2 billion to $1.3 billion 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. We also may engage in non-core 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 decrease in the future as a result of a 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 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.

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.

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 prospectus represent the current market value of our estimated oil and natural gas reserves. Finally, the timing of the production and the expenses related 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.

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We account for our activities under the successful efforts method of accounting. Changes in the present 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 present 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 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. Declines in commodity prices can also impact the number of service providers for such drilling rigs, equipment, supplies or qualified personnel, contributing to or also resulting in the shortages. 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:

- *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

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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 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. As a result, the success and timing of our drilling and development activities on properties operated by others 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.

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, 2014, four purchasers accounted for approximately 80% 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.

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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 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 and hedging activities. 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, they may not be adequate to fully eliminate the credit risk associated with our counterparties, contractors and suppliers.

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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 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 a majority 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 a majority 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.

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 industry 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.

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We may be affected by skilled labor shortages, which we have from time-to-time experienced, especially in North American regions where there are large unconventional shale resource plays. These 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.

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 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.

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 growth 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.

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.

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. According to the Lower Colorado River Authority, during 2011, Texas experienced the lowest inflows of water of any year in recorded history. As a result of this severe drought, at least one local water district has begun restricting the use of water subject to its jurisdiction for hydraulic fracturing to 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;

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- 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;
- 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 most of our reserves are located on leases that are held-by-production or held by continuous development, we do have provisions in many 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 existing 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.

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

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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.

Given the decline in commodity prices, especially oil, we may incur impairment charges in the future depending on the value of our proved reserves, which are subject to change as a result of factors such as prices, costs and well performance. Currently, our reserves are based on the first day 12-month average prices of $94.99 per barrel of oil and $4.34 per MMBtu of natural gas, which are above the current strip price. Additionally, we could incur significant impairment charges of our unproved property should 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.

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 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. The EPA has also recently proposed amendments to include reporting of emissions from completions and workovers of oil wells using hydraulic fracturing, as well as emissions from gathering and boosting systems. This proposed amendment is open for public comment through February 24, 2015. 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 proposed New Source Performance Standards for new coal-fired and natural gas-fired power plants published January 8, 2014. 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

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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). From the EPA, such rulemaking may address green completions for hydraulically-fractured oil wells, emissions from pneumatic devices, and fugitive emissions at new or modified sources. The EPA is also expected to propose new guidelines in summer 2015 to reduce ozone precursors from oil and gas sources in nonattainment areas, in addition to already-proposed changes to the National Air Quality Ambient Standards for ozone. The BLM is expected to propose updated standards for venting and flaring in spring 2015. Similarly in 2015, the PHMSA is expected to propose natural gas pipeline safety standards that will concurrently reduce methane emissions. 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.

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. Such regulations are expected to be issued in draft form in early 2015. 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.

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 Progress Report in December 2012 and a final draft was anticipated by 2014 for peer review and public comment, but has not yet been released. 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, 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 (SO2) and volatile organic compounds (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

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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 new 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 has proposed rules requiring similar disclosure of hydraulic fracturing fluid used on BLM lands to FracFocus.org and optionally directly to the BLM.

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;
- 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.

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

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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 8 to our consolidated financial statements and elsewhere in this 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.

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.

In addition, the credit markets and the financial services industry in recent years has experienced a period of unprecedented turmoil and upheaval characterized by the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States government. These circumstances and events led to reduced credit availability, tighter lending standards and higher interest rates on loans. 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.

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 a 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.

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 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 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;

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- 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.

In addition, the RBL Facility requires us to comply with certain financial covenants. See Note 7 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, our senior secured term loan and our senior secured notes.

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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 8, 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, 2015, we had 19 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 our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange:

2014	**High**	**Low**
Fourth Quarter	$ 16.79	$ 7.16
Third Quarter	22.55	16.98
Second Quarter	23.05	18.30
First Quarter	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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	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

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, 2014 and December 31, 2013 and the statements of income data and statements of cash flow data for the years ended December 31, 2014 and December 31, 2013 and for the period from February 14 to December 31, 2012 and the period from January 1, 2012 through May 24, 2012, 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, 2012 from the consolidated financial statements of EP Energy Corporation, and the selected historical consolidated balance sheet as of December 31, 2011 and 2010, and the statements of income data and statements of cash flow data for the years ended December 31, 2011 and 2010 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. Financial statement periods after May 24, 2012 (successor periods) also present certain domestic natural gas assets sold as discontinued operations. 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,	Year ended December 31,	February 14 to December 31,	January 1, to May 24,	Years ended December 31,	
	2014	2013	2012	2012	2011	2010
	(in millions, except per common share amounts)					
Results of Operations						
Operating revenues	$ 3,084	$ 1,576	$ 681	$ 932	$ 1,756	$ 1,704
Operating income (loss)	1,493	383	(72)	338	648	738
Interest expense	(318)	(354)	(219)	(14)	(14)	(23)
Income (loss) from continuing operations	727	(56)	(306)	187	385	451
Basic and diluted net income (loss) per common share						
Income (loss) from continuing operations	$ 3.00	$ (0.27)	$ (1.46)			
Cash Flow						
Net cash provided by (used in):						

Operating activities	$ 1,186	$ 960	$ 449	$ 580	$ 1,426	$ 1,067
Investing activities	(2,044)	(475)	(7,893)	(628)	(1,237)	(1,130)
Financing activities	829	(503)	7,513	110	(238)	(46)
	As of December 31,			As of December 31,		
	2014	**2013**	**2012**	**2011**	**2010**	
			(in millions)			
Financial Position						
Total assets	$ 10,219	$ 8,366	$ 8,306	$ 5,103	$ 4,942	
Long-term debt	4,598	4,421	4,695	851	301	
Stockholders / Member s equity	4,348	2,937	2,748	3,100	3,067	

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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 year ended December 31, 2014, we recorded realized and unrealized gains on financial derivatives of $985 million. 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 years ended December 31, 2011 and 2010, we recorded realized and unrealized gains on financial derivatives included in operating revenues of $365 million, $284 million and $390 million, and non-cash ceiling test and other impairment charges of $62 million, $6 million and $25 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 . Our 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. Additionally, the financial results for the successor period subsequent to the Acquisition includes the application of the acquisition method of accounting and the application of the successful efforts method of accounting for oil and natural gas properties. All periods included in these financial statements present our Brazil operations as discontinued operations. The successor periods present certain domestic natural gas assets sold, including the South Louisiana Wilcox, CBM, South Texas and Arklatex assets as discontinued operations. Predecessor periods do not present these domestic sales as discontinued operations due to the application of the full cost method of accounting prior to the Acquisition. As a result of these differences in presentation, year-over-year results may not be comparable. 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 which are further described in Item I, Business:

- ***Eagle Ford Shale.*** The Eagle Ford Shale in South Texas continues to provide the highest economic returns in our portfolio.

- ***Wolfcamp Shale.*** In our Wolfcamp Shale program, located in the Permian Basin in West Texas, we are focused on optimizing our drilling, completion and artificial lift systems.

- ***Altamont.*** In the Altamont Field in the Uinta Basin in northeastern Utah, we are gaining operational efficiencies as we develop this oil field. Most of our acreage in this area is held-by-production.

- ***Haynesville Shale.*** The Haynesville Shale in north Louisiana generates positive cash flow, and our acreage in the Haynesville Shale is held-by-production, giving us the flexibility to allocate capital to this natural gas asset based on returns available in the commodity price environment.

We evaluate growth opportunities that are aligned on our core competencies and that are in areas that can provide a competitive advantage. Strategic acquisitions of leasehold acreage or producing assets can provide us with opportunities to achieve our long-term goals by leveraging existing expertise in each of our operating 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.

During 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 $152 million. The acquisition represents an approximate 25% expansion of our current 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) for approximately $150 million of cash proceeds, with the buyer also assuming a transportation commitment of approximately $20 million (ii) our Brazilian operations and (iii) certain non-core acreage in Atascosa County in Eagle Ford for approximately $28 million of cash proceeds. We recorded a $10 million loss on the sale of our Arklatex and South Louisiana Wilcox assets and no gain or loss on the other sales.

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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:

- 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 (e.g., oil spills).

To the extent possible, we attempt to mitigate certain of these risks through actions such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to stabilize cash flows and reduce the financial impact of downward commodity price movements on commodity sales. In addition, because we apply mark-to-market accounting, our reported results of operations, financial position and cash flows 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 the underlying sales contract. In order to stabilize cash flows and protect the economic assumptions associated with our capital investment programs, we enter into financial derivative contracts to reduce the financial impact of unfavorable commodity price movements and locational price differences. Certain derivative contracts, usually short term in nature (less than one year), involve the receipt or payment of premiums. During 2014, we received approximately $1 million in premiums on such derivative contracts, all of which settled during 2014.

During 2014, we (i) settled commodity index hedges on approximately 97% of our oil production (84% of our total liquids production) and 100% of our natural gas production at average floor prices of $97.99 per barrel of oil and $4.02 per MMBtu, respectively and (ii) hedged basis risk on approximately 60% of our 2014 Eagle Ford oil 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, 2014.

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	2015			2016		
	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)
Oil						
Fixed Price Swaps						
WTI	17,373	$	89.34	5,216	$	85.25
Brent	2,555	$	100.01		$	
LLS		$		5,124	$	91.88
Ceilings	1,095	$	100.00		$	
Three Way Collars						
Ceiling - Brent	1,095	$	110.02		$	
Floors - Brent(2)	1,095	$	100.00		$	
Ceiling - LLS		$		4,758	$	94.96
Floors - LLS(3)		$		4,758	$	90.19
Basis Swaps						
LLS vs. WTI(4)	3,285	$	4.28	183	$	3.00
LLS vs. Brent(5)	3,650	$	(3.77)	4,026	$	(3.58)
Midland vs. Cushing(6)	1,095	$	(0.65)		$	
Natural Gas						
Fixed Price Swaps	62	$	4.26	7	$	4.20
Basis Swaps(7)						
TGP	1	$	(0.10)		$	
CIG	4	$	(0.25)		$	
Waha	4	$	(0.07)		$	

(1) Volumes presented are MBbls for oil and TBtu for natural gas. Prices presented are per Bbl of oil and MMBtu of natural gas.

(2) If market prices settle at or below $85.00 in 2015, we will receive a locked-in cash settlement of the market price plus $15.00 per Bbl.

(3) If market prices settle at or below $76.54 in 2016, we will receive a locked-in cash settlement of the market price plus $13.65 per Bbl.

(4) EP Energy receives WTI plus basis spread listed and pays LLS.

(5) EP Energy receives Brent plus basis spread listed and pays LLS.

(6) EP Energy receives Cushing plus basis spread listed and pays Midland.

(7) EP Energy receives the basis spread listed and pays TGP, CIG and Waha basis.

The following table reflects the volumes and the prices associated with derivative contracts entered into between January 1, 2015 and February 16, 2015, which are not reflected in the table above.

	2016			2017		
	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)
Oil						
Fixed Price Swaps						
WTI(2)	3,294	$	71.77	4,015	$	66.11

Basis Swaps				
LLS vs. WTI(3)	1,830	$	4.00	$

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(1) Volumes presented are MBbls. Prices presented are per Bbl.

(2) In February 2015, we unwound 3,294 MBbls of 2016 LLS three way collars in exchange for 3,294 MBbls of 2016 WTI fixed price swaps. No cash or other consideration was included as part of this exchange.

(3) In February 2015, we unwound 1,830 MBbls of 2016 LLS vs. Brent basis swaps in exchange for 1,830 MBbls of 2016 LLS vs. WTI basis swaps. No cash or other consideration was included as part of this exchange.

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Summary of Liquidity and Capital Resources. As of December 31, 2014, we had available liquidity, including existing cash, of approximately $1.84 billion. We believe we have sufficient liquidity for 2015 from our cash flows from operations (including our hedging program), combined with the availability under our RBL Facility and available cash, to fund our current obligations, projected working capital requirements and our capital spending plan. Additionally, the earliest maturity date of our debt obligations is in 2017 when amounts outstanding under our RBL Facility mature. Finally, given recent declines in oil prices, we believe our oil and natural gas hedge positions also provide significant price protection to our near-term revenues and cash flows. See Liquidity and Capital Resources for more information.

Outlook . For 2015, we expect the following:

- Capital expenditures of approximately $1.2 billion to $1.3 billion, allocated primarily to our oil programs: $825 million for Eagle Ford, $190 million for Wolfcamp, $140 million for Altamont and $100 million for Haynesville.

- Well completions between 160 and 190.

- Average daily production volumes for the year of approximately 94.5 MBoe/d to 109.5 MBoe/d, including average daily oil production volumes of approximately 56 MBbls/d to 64 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately $10.50 to $13.50 per Boe, and transportation costs of $2.90 to $3.35 per Boe.

- Per unit depreciation, depletion and amortization rate for the year of approximately $25.00 to $27.00 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:

	2014	2013	2012
United States (MBoe/d)			
Eagle Ford Shale	51	37	20
Wolfcamp Shale	15	5	2
Altamont	16	12	11
Haynesville Shale	16	27	48
Other			2
Divested assets(1)		6	31
Total	98	87	114
Oil (MBbls/d)			
Consolidated volumes	55	36	23
Divested assets(1)		1	2
Total Combined	55	37	25
Natural Gas (MMcf/d)			
Consolidated volumes	190	230	341
Divested assets(1)		28	161
Total Combined	190	258	502
NGLs (MBbls/d)			
Consolidated volumes	11	7	3
Divested assets(1)		1	2
Total Combined	11	8	5

(1) 2013 volumes include 6 MBoe/d, 1 MBbls/d of oil, 28 MMcf/d of natural gas and 1 MBbls/d of NGLs from Four Star Oil & Gas Company (Four Star), our equity investment sold in September 2013. 2012 volumes include 9 MBoe/d, 1 MBbls/d of oil, 42 MMcf/d of natural gas and 1 MBbls/d of NGLs from Four Star. Remaining volumes are from our Arklatex and South Louisiana Wilcox areas sold in 2014, CBM and South Texas assets sold in 2013, and our Gulf of Mexico assets, which were sold in 2012. For periods after May 24, 2012, Arklatex, South Louisiana Wilcox, CBM and South Texas assets are treated as discontinued operations and accordingly volumes relating to those assets are excluded from all financial and non-financial metrics. In addition, our Brazilian operations are treated as discontinued operations in all periods and, accordingly, volumes are excluded from all financial and non-financial metrics for both predecessor and successor periods.

- *Eagle Ford Shale* Our Eagle Ford Shale equivalent volumes and oil production increased 14 MBoe/d (approximately 38%) and 11 MBbls/d (45%), respectively, for the year ended December 31, 2014 compared to 2013 due to the success of our drilling program in the area. During 2014, we completed 136 additional operated wells in the Eagle Ford, and we had a total of 399 net operated wells as of December 31, 2014. With a majority of our acreage located in the core of the oil window, primarily in LaSalle county, we continue to grow our oil and NGLs production in the area. We closed the sale of certain non-core acreage in Atascosa County for approximately $28 million in December 2014.

- *Wolfcamp Shale* Our Wolfcamp Shale equivalent volumes increased 10 MBoe/d (approximately 200%) for the year ended December 31, 2014 compared to 2013 as we continued to progress the development of the program. During 2014, we completed 90 additional operated wells, for a total of 201 net operated wells as of December 31, 2014 (which includes wells acquired in April 2014).

- *Altamont* Our Altamont equivalent volumes increased 4 MBoe/d (approximately 33%) for the year ended December 31, 2014 compared to 2013. Altamont produced an average of 12 MBbls/d of oil during 2014, and we completed an additional 47 operated oil wells for a total of 356 net operated wells at December 31, 2014. In October 2014, the Utah Board of Oil, Gas and Mining provisionally approved 80-acre well density on approximately 50,000 of our Altamont net acreage.

- *Haynesville Shale* Our Haynesville Shale equivalent volumes decreased 11 MMcf/d (approximately 41%) for the year ended December 31, 2014 compared to 2013, due to natural production declines. As of December 31, 2014, we had 99 net operated wells in the Haynesville Shale, and our total natural gas production for 2014 was approximately 96 MMcf/d. We have allocated a portion of our capital budget in 2015 to our Haynesville drilling program based on its returns in the forecasted commodity price environment.

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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)

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(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 which includes both successor and predecessor capital costs. For 2012, capital costs utilized in this ratio reflect the combined predecessor and successor periods as further described in *Results of Operations* below. 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, 2014 internal reserve report to be spent in 2015, 2016 and 2017 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, 2014, proved developed reserves represented approximately 38% 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 domestic operations for each of the years ended December 31:

	Including Price Revisions			Excluding Price Revisions(1)		
	2014	2013	2012	2014	2013	2012
Reserve Replacement Ratios(2)	343%	476%	47%	254%	464%	298%
Proved Developed Reserves(3)	38%	33%	46%	38%	33%	46%
Proved Undeveloped Reserves(3)	62%	67%	54%	62%	67%	54%
Reserve Replacement Costs(2)(4)($/Boe)	$ 16.93	$ 12.62	$ 67.56	$ 22.85	$ 12.95	$ 10.74

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

(2) 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 years ended December 31, 2013 and 2012, as any such amounts are immaterial to the amounts presented.

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

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

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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 domestic operations for the three years ended December 31, 2014.

	Including Price Revisions	Excluding Price Revisions
	Three years ended December 31, 2014 ($/Boe)	
Reserve Replacement Costs		
Excluding acquisitions	$ 18.64	$ 14.47
Including acquisitions	$ 18.59	$ 14.51

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Results of Operations

The information below reflects financial results for EP Energy Corporation for the years ended December 31, 2014 and 2013, for the period from February 14 (the formation date of EPE Acquisition LLC, which upon a Corporate Reorganization on August 30, 2013 became a subsidiary of the new parent EP Energy Corporation) to December 31, 2012, and for the period from January 1 to May 24, 2012. Our financial results, beginning with the Acquisition on May 24, 2012, reflect the application of the acquisition method of accounting, the application of the successful efforts method of accounting for oil and natural gas properties, and the presentation of certain domestic natural gas assets divested in 2014 and 2013 and the sale of our Brazilian operations as discontinued operations. For periods prior to the Acquisition or the predecessor periods, we have not reflected these divested domestic natural gas assets as discontinued operations since they did not qualify as such for accounting purposes under the full cost accounting method applied by the predecessor during those periods. We have reflected our Brazilian operations as discontinued operations in all periods. As a result, trends and results in periods after the Acquisition and future periods may be different than those prior to the Acquisition.

Prior to the Acquisition, we had no independent oil and gas operations, and accordingly there were no operational exploration and production activities that changed as a result of the Acquisition. Consequently, in certain period-to-period explanations that follow we have provided supplemental information that compares (i) results for the year ended December 31, 2014 with results for the year ended December 31, 2013 and (ii) results for the year ended December 31, 2013 with results for the successor period from February 14 to December 31, 2012 and for the predecessor period from January 1 to May 24, 2012 on a combined basis and excluding divested assets (such combined period is referred to as the combined year ended December 31, 2012). We have provided this additional analysis for comparability of results and to aid in the analysis and understanding of our operating performance period over period. Any non-GAAP analysis is provided as supplemental financial information to our GAAP results and is not intended to be a substitute for our reported successor and predecessor period GAAP results.

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

	Year-to-Date Periods			
	2014	2013	2012	
	Successor			Predecessor
	Year ended December 31,	Year ended December 31,	February 14 to December 31	January 1 to May 24
			(in millions)	
Operating revenues:				
Oil	$ 1,705	$ 1,254	$ 499	$ 310
Natural gas	284	300	216	228
NGLs	110	74	28	29
Total physical sales	2,099	1,628	743	567
Financial derivatives	985	(52)	(62)	365
Total operating revenues	3,084	1,576	681	932
Operating expenses:				
Natural gas purchases	23	25	19	
Transportation costs	100	85	48	45
Lease operating expenses	193	147	63	80
General and administrative	244	229	358	69
Depreciation, depletion and amortization	875	585	188	307
Impairment and ceiling test charges	2	2	1	62

Exploration and other expense	25	41	40	
Taxes, other than income taxes	129	79	36	31
Total operating expenses	1,591	1,193	753	594
Operating income (loss)	1,493	383	(72)	338
Other income (expense)	1	(12)	(1)	(3)
Loss on extinguishment of debt	(17)	(9)	(14)	
Interest expense	(318)	(354)	(219)	(14)
Income (loss) from continuing operations before income taxes	1,159	8	(306)	321
Income tax expense	432	64		134
Income (loss) from continuing operations	727	(56)	(306)	187
Income (loss) from discontinued operations, net of tax	4	506	50	(9)
Net income (loss)	$ 731	$ 450	$ (256)	$ 178

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the years ended December 31, 2014 and 2013, and for each of the successor and predecessor periods in 2012. 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-to-Date Periods			
	2014	2013	2012	
	Year ended December 31,	Successor Year ended December 31,	February 14 to December 31	Predecessor January 1 to May 24
			(in millions)	
Operating revenues(1):				
Oil	$ 1,705	$ 1,254	$ 499	$ 310
Natural gas	284	300	216	228
NGLs	110	74	28	29
Total physical sales	2,099	1,628	743	567
Financial derivatives	985	(52)	(62)	365
Total operating revenues	$ 3,084	$ 1,576	$ 681	$ 932
Volumes(1):				
Oil (MBbls)(2)	19,985	13,432	5,824	3,220
Natural gas (MMcf)(2)	69,434	93,866	82,743	101,157
NGLs (MBbls)(2)	4,116	2,761	1,122	863
Equivalent volumes (MBoe)(2)	35,673	31,837	20,736	20,943
Total MBoe/d(2)	98	87	94	144
Consolidated prices per unit(3):				
Oil				
Average realized price on physical sales ($/Bbl)(4)	$ 85.31	$ 94.75	$ 88.17	$ 99.76
Average realized price, including financial derivatives ($/Bbl)(4)(5)	$ 88.77	$ 97.56	$ 95.59	$ 99.61
Natural gas				
Average realized price on physical sales ($/Mcf)(4)	$ 3.76	$ 3.28	$ 2.68	$ 2.40
Average realized price, including financial derivatives ($/Mcf)(4)(5)	$ 3.34	$ 2.97	$ 5.05	$ 4.15
NGLs				
Average realized price on physical sales ($/Bbl)	$ 26.73	$ 30.58	$ 33.47	$ 42.94
Average realized price, including financial derivatives ($/Bbl)(5)	$ 27.78	$	$	$

(1) Operating revenues and volumes in the successor periods do not include amounts associated with domestic natural gas assets sold. All periods presented do not include Brazilian operations sold in 2014.

(2) In September 2013, we sold our equity investment in Four Star. For the year ended December 31, 2013, the period from February 14 to December 31, 2012 and the predecessor period from January 1 to May 24, 2012, Four Star s production volumes were 197 MBbls, 167 MBbls and 115 MBbls of oil; 10,050 MMcf, 9,242 MMcf and 6,310 MMcf of natural gas; 327 MBbls, 288 MBbls and 190 MBbls of NGLs; and 2,199 MBoe (6 MBoe/d), 1,995 MBoe (9 MBoe/d) and 1,357 MBoe (9 MBoe/d) of equivalent volumes, respectively.

(3) Natural gas prices for the years ended December 31, 2014 and 2013 and from February 14 to December 31, 2012 are calculated including a reduction of $23 million, $25 million and $19 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.

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

(5) The years ended December 31, 2014 and 2013 and from February 14 to December 31, 2012 include approximately $30 million of cash paid, $28 million of cash paid and approximately $175 million of cash received for the settlement of natural gas financial derivatives. The predecessor period from January 1 to May 24, 2012 includes approximately $165 million of cash received for the settlement of natural gas financial derivatives. The years ended December 31, 2014 and 2013 and the period from February 14 to December 31, 2012 include approximately $69 million, $29 million and $45 million, respectively, of cash receipts for the settlement of crude oil derivative contracts.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the year ended December 31, 2014, physical sales increased by $471 million (29%), compared to the year ended December 31, 2013. For the year ended December 31, 2013, physical sales increased by $318 million (24%) compared to the combined year ended December 31, 2012. Physical sales have increased primarily due to oil volume growth from our Eagle Ford and Wolfcamp drilling programs, partially offset by decreases in natural gas sales in Haynesville. The table below displays the price and volume variances on our physical sales when comparing the years ended December 31, 2014 and 2013.

	Oil	Natural gas	NGLs	Total
		(in millions)		
December 31, 2013 sales	$ 1,254	$ 300	$ 74	$ 1,628
Change due to prices	(188)	35	(16)	(169)
Change due to volumes	639	(51)	52	640
December 31, 2014 sales	$ 1,705	$ 284	$ 110	$ 2,099

Oil sales for the year ended December 31, 2014, compared to the year ended December 31, 2013, increased by $451 million (36%), mainly from growth in our Eagle Ford drilling program. In 2014, Eagle Ford oil production volumes increased by 45% (11 MBbls/d) compared with the year ended December 31, 2013. In addition, Wolfcamp oil production volumes increased by 140% (5 MBbls/d). For the year ended December 31, 2013, oil sales increased by $445 million compared to the combined year ended December 31, 2012 attributable to a 60% increase (14 MBbls/d) in consolidated oil volumes in our Eagle Ford, Wolfcamp and Altamont operating areas.

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, partially offset by higher natural gas prices. Natural gas sales decreased for the year ended December 31, 2013 compared with the combined year ended December 31, 2012 (excluding amounts related to divested assets) primarily due to lower natural gas prices and the decrease in volumes in Haynesville.

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,			
	2014		2013	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)

Differentials and deducts	$	(7.69)	$	(0.60)	$	(3.35)	$	(0.32)
NYMEX	$	92.99	$	4.41	$	97.97	$	3.65

The larger differentials and deducts in the year ended December 31, 2014 were generally a result of wider basis differentials in areas currently facing oversupply due to a combination of temporary refinery outages and insufficient takeaway capacity along with slightly higher market prices of natural gas.

NGLs sales increased for the year ended December 31, 2014 compared with the year ended December 31, 2013 and for the year ended December 31, 2013 compared to the combined year ended December 31, 2012. Although average realized prices decreased in 2014 and 2013 compared to the previous years, NGLs volume increases have more than offset the price decline primarily as a result of our Eagle Ford drilling program. Eagle Ford NGLs volumes increased by 32% (2 MBbls/d) over the year ended December 31, 2013.

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As of December 31, 2014, the NYMEX spot price of a barrel of oil was $53.27 versus the NYMEX spot price of natural gas of $2.89, or a ratio of 18 to 1. Despite further recent declines in oil prices, the value difference between these commodities is such that we will continue to target increases in our oil volumes in our capital budget. Growth in our overall oil sales (including the impact of financial derivatives) will largely be impacted by our ability to grow these volumes and will also be impacted by commodity pricing to the extent we are unhedged and by the nature of our hedge contracts. Based on our hedges in place as of December 31, 2014, we are approximately 96% hedged (based on the midpoint of our 2015 production guidance) at $91.19 per barrel for 2015. These hedge positions consist of 95% fixed price swaps and three way collars (locking in $15 per barrel in excess of market prices should NYMEX settle below $85.00) comprising the remaining positions. For additional details on our 2015 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, 2014, we recorded $985 million of derivative gains compared to a derivative loss of $52 million during the year ended December 31, 2013. Realized and unrealized gains for the combined year ended December 31, 2012 were $303 million of derivative gains.

Operating Expenses

Transportation costs. Transportation costs for the years ended December 31, 2014 and 2013, and for the period from February 14 to December 30, 2012 were $100 million, $85 million and $48 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $45 million (including $20 million of transportation costs related to divested assets). Total transportation costs (excluding amounts related to the divested assets) have increased over the three year period beginning in 2012 due to oil transportation costs associated with Eagle Ford and Wolfcamp as a result of our production growth and new contracts in these areas.

Lease operating expense. Lease operating expense for the years ended December 31, 2014 and 2013, and for the period from February 14 to December 31, 2012 were $193 million, $147 million and $63 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $80 million (including $36 million of lease operating expense related to divested assets). Total lease operating expense has increased in 2014 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. Lease operating expense for the year ended December 31, 2013 increased compared to the combined year ended December 31, 2012 (excluding amounts related to divested assets) due to increased equipment and chemical costs in our Eagle Ford play and higher maintenance, repair and power costs.

General and administrative expenses. General and administrative expense for the years ended December 31, 2014 and 2013, and for the period from February 14 to December 31, 2012 were $244 million, $229 million and $358 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $69 million. 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 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. Our transaction and management fee agreements with our Sponsors terminated with the completion of our initial public offering in January 2014.

General and administrative expenses for the year ended December 31, 2013 decreased $198 million compared to the combined year 2012 primarily due to the transition and restructuring costs of $221 million ($173 million of acquisition related costs and $48 million of transition and severance costs) recorded in 2012 as a result of the Acquisition, partly offset by an increase of $11 million in management consulting and advisory service charges reflected for the year ended December 31, 2013. Prior to the Acquisition, El Paso allocated general and administrative costs to us based on the estimated level of resources devoted to our operations and the relative size of our earnings before interest and taxes, gross property and payroll.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the years ended December 31, 2014 and 2013, and for the period from February 14 to December 31, 2012 were $875 million, $585 million and $188 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $307 million. Our depreciation, depletion and amortization costs have increased over the three year period beginning in 2012 due to increases in production volumes and the ongoing development of higher cost oil programs (e.g. Eagle Ford and Wolfcamp). Depreciation, depletion and amortization for the year ended December 31, 2013 also reflects the step up in 2012 in the book basis of our oil and natural gas assets as a result of the Acquisition. We expect our depletion rate will continue to increase as compared to our current levels as a result of this ongoing

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development of our higher cost liquids programs. Our average depreciation, depletion and amortization costs per unit for the year-to-date periods were:

	Year-to-Date Periods			
	2014	2013	2012	
	Successor			Predecessor
	Year ended December 31,	Year ended December 31,	February 14 to December 31	January 1 to May 24
Depreciation, depletion and amortization ($/Boe)(1)	$ 24.53	$ 19.74	$ 10.07	$ 15.66

(1) Includes $0.07 per Boe for each of the years ended December 31, 2014 and 2013, $0.09 per Boe for the period from February 14 to December 31, 2012 and $0.23 per Boe for the predecessor period from January 1 to May 24, 2012 related to accretion expense on asset retirement obligations.

Impairment and ceiling test charges. We apply the successful efforts method of accounting and evaluate capitalized costs related to proved properties at least annually or upon a triggering event to determine if impairment of such properties is necessary. Forward commodity prices can play a significant role in determining impairments. Considering the significant amount of fair value allocated to our oil and natural gas properties in conjunction with the Acquisition and the continued decline in commodity prices, sustained lower oil and/or natural gas prices from present levels or further declines could result in an impairment of the carrying value of our proved or unproved properties in the future. For additional discussion see *Critical Accounting Policies*.

Prior to the Acquisition in May 2012, the predecessor used the full cost method of accounting. Under this method of accounting, quarterly ceiling tests of capitalized costs were conducted in each of the full cost pools and costs outside of the full cost depletion base were periodically assessed for impairment. During the predecessor period from January 1, 2012 to May 24, 2012, the predecessor recorded a non-cash charge of approximately $62 million as a result of the decision to end exploration activities in Egypt. In June of 2012, the predecessor sold all its interests in Egypt.

Exploration and other expense. Exploration and other expense for the year ended December 31, 2014 and 2013, and for the period from February 14 to December 31, 2012 were $25 million, $41 million and $40 million, respectively. Exploration expense is the result of applying the successful efforts method of accounting following the Acquisition. Prior to the Acquisition, exploration costs were capitalized under full cost accounting. Included in exploration expense for the year ended December 31, 2014 is $18 million of amortization of unproved leasehold costs. In addition, in 2014, we recorded approximately $3 million as other expense in conjunction with the early termination of a contract for drilling rig commitments.

Taxes, other than income taxes. Taxes, other than income taxes for the years ended December 31, 2014 and 2013, and for the period from February 14 to December 31, 2012, were $129 million, $79 million and $36 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $31 million (including approximately $14 million of taxes, other than income taxes related to divested assets). Production taxes have increased (excluding amounts related to divested assets) over the three year period beginning in 2012 due to higher severance taxes associated with growing production volumes in our oil producing areas. Additionally, year-to-date 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, natural gas purchases, impairments and ceiling test 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:

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	Year-to-Date Periods						
	2014		2013		2012			
	Successor						Predecessor	
	Year ended December 31,		Year ended December 31,		February 14 to December 31		January 1 to May 24	
	Total	Per Unit(1)	Total	Per Unit(1)	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)							
Total continuing operating expenses	$ 1,591	$ 44.59	$ 1,193	$ 40.26	$ 753	$ 40.19	$ 594	$ 30.32
Depreciation, depletion and amortization	(875)	(24.53)	(585)	(19.74)	(188)	(10.07)	(307)	(15.66)
Transportation costs	(100)	(2.81)	(85)	(2.85)	(48)	(2.54)	(45)	(2.32)
Exploration expense(2)	(22)	(0.62)	(41)	(1.39)	(40)	(2.13)		
Natural gas purchases	(23)	(0.64)	(25)	(0.85)	(19)	(1.04)		
Impairment and ceiling test charges	(2)	(0.05)	(2)	(0.06)	(1)	(0.06)	(62)	(3.15)
Total continuing cash operating costs	569	15.94	455	15.37	457	24.35	180	9.19
Transition/restructuring costs, non-cash portion of compensation expense and other(3)	(95)	(2.67)	(65)	(2.19)	(266)	(14.19)	(11)	(0.58)
Total adjusted cash operating costs and adjusted per-unit cash costs(3)	$ 474	$ 13.27	$ 390	$ 13.18	$ 191	$ 10.16	$ 169	$ 8.61
Total equivalent volumes (MBoe)(4)	35,673		29,638		18,741		19,586	

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

(2) For the year ended December 31, 2014, amount does not include approximately $3 million recorded in conjunction with early rig termination fees included in exploration and other expense on our consolidated income statement.

(3) 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, 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 period from February 14 to December 31, 2012 includes transition and severance costs of $215 million, management fees paid to our Sponsors of $16 million and $35 million of non-cash compensation expense. The predecessor period from January 1 to May 24, 2012 includes severance costs of $5 million and $6 million of non-cash compensation expense. 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.

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

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

Year-to-Date Periods

	2014	2013	2012	
		Successor		Predecessor
	Year ended December 31,	Year ended December 31,	February 14 to December 31	January 1 to May 24
Average cash operating costs ($/Boe)				
Lease operating expenses	$ 5.40	$ 4.98	$ 3.34	$ 4.07
Production taxes(1)	3.39	2.84	1.88	1.79
General and administrative expenses(2)	6.83	7.73	19.07	3.53
Taxes, other than production and income taxes(3)	0.23	(0.18)	0.06	(0.20)
Other expense(4)	0.09			
Total cash operating costs	15.94	15.37	24.35	9.19
Transition/restructuring costs, non-cash portion of compensation expense and other(2)	(2.67)	(2.19)	(14.19)	(0.58)
Total adjusted cash operating costs	$ 13.27	$ 13.18	$ 10.16	$ 8.61

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

(2) For additional detail of 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) Recorded in conjunction with early rig termination fees.

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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, 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 the PIK toggle note. For the year ended December 31, 2013, we recorded a $9 million loss on extinguishment of debt for the portion of deferred financing costs written off in conjunction with (i) the repayment of approximately $250 million under each of our $750 million and $400 million term loans, (ii) our $750 million term loan re-pricing in May 2013 and (iii) the semi-annual redeterminations of our RBL Facility in March 2013. For the year ended December 31, 2012, we recorded a $14 million loss on the extinguishment of debt for the pro-rata portion of deferred financing costs written off, debt discount and call premiums paid related to the re-pricing of our existing $750 million term loan.

Interest expense. 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. Interest expense for the year ended December 31, 2013 compared to 2012 increased due to the issuance of approximately $4.25 billion of debt in conjunction with the Acquisition in May 2012. Prior to the Acquisition and related financing transactions, interest expense primarily related to borrowings under the predecessor s $1 billion credit facility in place at that time.

Income taxes. For the year ended December 31, 2014, our effective tax rate was 37.3%, higher than the statutory rate of 35% primarily as a result of state income taxes, net of federal income tax effect, and incremental non-cash income tax expense recorded in conjunction with changing our organizational structure in December 2014. The effective tax rate for both the year ended December 31, 2013 and the period from February 14 to December 31, 2012, differed than the statutory rate primarily due to 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 those periods. The effective tax rate for the predecessor period from January 1, 2012 to May 24, 2012, was 42%, significantly higher than the statutory rate, primarily due to the impact of an Egyptian non-cash charge without a corresponding tax benefit.

Income (loss) from discontinued operations. Our income (loss) from discontinued operations for the year ended December 31, 2014 includes the financial results of assets classified as discontinued operations and any gain (loss) recorded on the sale of these non-core domestic natural gas and other assets. Our income (loss) from discontinued operations for 2013 includes a $468 million gain on the sale of assets during 2013.

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Supplemental Non-GAAP Measures

We use the non-GAAP measures EBITDAX , Adjusted EBITDAX and Pro Forma 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 cash settlements and 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 our Sponsors, losses on extinguishment of debt, equity earnings from Four Star prior to its sale in 2013, and impairment and ceiling test charges. Pro Forma Adjusted EBITDAX is defined as total Adjusted EBITDAX less Adjusted EBITDAX related to divested assets.

We believe that the presentation of EBITDAX, Adjusted EBITDAX and Pro Forma 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, Adjusted EBITDAX and Pro Forma 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.

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

	Successor			Predecessor
	Year ended December 31, 2014	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
	(in millions)			
Net income (loss)	$ 731	$ 450	$ (256)	$ 178
(Income) loss from discontinued operations, net of tax	(4)	(506)	(50)	9
Income (loss) from continuing operations	727	(56)	(306)	187
Income tax expense	432	64		134
Interest expense, net of capitalized interest	318	354	219	14
Depreciation, depletion and amortization	875	585	188	307
Exploration expense(1)	22	41	40	
EBITDAX	2,374	988	141	642
Mark-to-market on financial derivatives(2)	(985)	52	62	(365)
Cash settlements and premiums on financial derivatives(3)	44	10	217	165
Non-cash portion of compensation expense(4)	9	31	35	6
Transition, restructuring and other costs(5)	(4)	8	144	5
Fees paid to Sponsors(6)	90	26	87	
Loss on extinguishment of debt(7)	17	9	14	
Loss from unconsolidated affiliate(8)		13	1	5
Impairments and ceiling test charges	2	2	1	62
Adjusted EBITDAX	1,547	1,139	702	520
Less: Adjusted EBITDAX divested assets(9)			5	83
Pro Forma Adjusted EBITDAX	$ 1,547	$ 1,139	$ 697	$ 437

(1) Represents exploration expense only and does not include $3 million of other expense recorded in 2014.

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

(3) Represents actual cash settlements received/(paid) related to financial derivatives, including cash premiums. For the years ended December 31, 2014 and 2013, we received approximately $1 million and $9 million of cash premiums, respectively, and for the period from February 14 to December 31, 2012 we paid $3 million of cash premiums. There were no cash premiums for the period from January 1 to May 24, 2012.

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

(5) Reflects an $11 million insurance settlement and $5 million of acquisition costs as well as transition and severance costs related to restructuring in 2014, severance costs incurred in connection with divested assets and costs incurred related to our initial public offering in 2013, and transaction costs paid as part of the Acquisition in 2012.

(6) Represents the transaction, management and other fees paid to the Sponsors.

(7) 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 and the re-pricing of the term loan in 2012.

(8) 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.

(9) Consists of Adjusted EBITDAX related to assets that have been divested, including our (i) Arklatex and South Louisiana Wilcox areas, (ii) CBM, South Texas and Arklatex assets and (iii) Gulf of Mexico assets.

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Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under the RBL Facility. Our primary uses of cash are capital expenditures, debt service requirements and working capital requirements. In January 2014, we completed our initial public offering of 35.2 million shares of Class A common stock and received net proceeds of approximately $669 million. We used the proceeds to repay our PIK toggle note and a portion of our outstanding RBL Facility balance. As of December 31, 2014, our available liquidity was approximately $1.84 billion, including approximately $1.8 billion of additional borrowing capacity available under the RBL Facility. In October 2014, we completed our semi-annual redetermination of this facility, increasing the borrowing base to $2.75 billion. Our next redetermination date is in April 2015.

We believe we have sufficient liquidity from (i) our cash flows from operations (including our significant multi-year hedge program), (ii) availability under the RBL Facility and (iii) available cash, to fund our capital program, current obligations and projected working capital requirements in 2015 and the foreseeable future. Additionally, the earliest maturity date of our obligations is in 2017 when amounts outstanding under our RBL Facility mature. Furthermore, despite the recent declines in oil prices, we believe our oil and natural gas derivative contracts provide significant commodity price protection to a substantial portion of our anticipated production for 2015 and 2016. These derivative contracts have been effective in minimizing the impact of price declines to our near-term revenues and also provide greater cash flow certainty. Based on our hedges in place as of December 31, 2014, we are approximately 96% hedged (based on the midpoint of our 2015 production guidance) at $91.19 per barrel for 2015. These hedge positions consist of 95% fixed price swaps and three way collars (locking in $15.00 per barrel in excess of market prices should NYMEX settle below $85.00) comprising the remaining hedge positions.

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 on the occurrence of certain events, such as a change of control, or (iii) obtain additional capital if required on acceptable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. We could be required to take additional future actions if necessary to address further changes in the financial or commodity markets.

Capital Expenditures. For 2015, we expect our total capital budget will be approximately $1.2 billion to $1.3 billion which reflects a reduction in capital spending given the current commodity price environment. We expect to spend a significant portion of our 2015 capital budget in our oil programs. However, in 2015, we also plan on allocating a portion of our capital to our Haynesville Shale natural gas assets based on the expected returns in this program. Our capital expenditures and our average drilling rigs for the twelve months ended December 31, 2014 were:

	Capital Expenditures (in millions)	Average Drilling Rigs
Eagle Ford Shale	$ 1,087	5.5
Wolfcamp Shale	822	3.5
Altamont	283	3.0
Haynesville Shale	8	
Other	3	
Total capital expenditures	$ 2,203	12.0

Long-Term Debt. As of December 31, 2014, our long-term debt is approximately $4.6 billion, comprised of $3.1 billion in senior notes due in 2019, 2020 and 2022, $646 million in senior secured term loans with maturity dates in 2018 and 2019 and $852 million outstanding under the

RBL Facility expiring in 2017. We continually monitor the debt capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining flexibility and cost efficiency. 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 7.

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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:

	Successor			Predecessor
	Year ended December 31, 2014	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
	(in millions)			
Cash Flow from Operations				
Operating activities				
Net income (loss)	$ 731	$ 450	$ (256)	$ 178
Impairment and ceiling test charges	20	46	1	62
Gain on sale of assets	(2)	(468)		
Other income adjustments	1,390	863	351	537
Change in other assets and liabilities	(953)	69	353	(197)
Total cash flow from operations	$ 1,186	$ 960	$ 449	$ 580
Other Cash Inflows				
Investing activities				
Proceeds from the sale of assets and investments, net of cash transferred	$ 154	$ 1,451	$ 110	$ 9
Financing activities				
Proceeds from issuance of long-term debt	2,455	1,880	5,825	215
Proceeds from issuance of stock	669			
Contributions		17	3,323	960
	3,124	1,897	9,148	1,175
Total cash inflows	$ 3,278	$ 3,348	$ 9,258	$ 1,184
Cash Outflows				
Investing activities				
Capital expenditures	$ 2,033	$ 1,924	$ 877	$ 636
Cash paid for acquisitions, net of cash acquired	165	2	7,126	1
	$ 2,198	$ 1,926	$ 8,003	$ 637
Financing activities				
Repayment of long-term debt	2,293	2,190	1,139	1,065
Distributions to members		205	337	
Debt issuance costs	1	5	159	
Other	1			
	2,295	2,400	1,635	1,065
Total cash outflows	$ 4,493	$ 4,326	$ 9,638	$ 1,702
Net change in cash and cash equivalents	$ (29)	$ (18)	$ 69	$ 62

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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, 2014, for each of the periods presented:

	2015	2016 - 2017	2018 - 2019 (in millions)	Thereafter	Total
Long-term financing obligations:					
Principal	$	$ 852	$ 1,400	$ 2,350	$ 4,602
Interest	317	618	514	135	1,584
Liabilities from derivatives	1				1
Operating leases	11	19			30
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	72	161	171	186	590
Other obligations	112	107			219
Total contractual obligations	$ 513	$ 1,757	$ 2,085	$ 2,671	$ 7,026

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.

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. Subsequent to December 31, 2014, we extended certain office leases and will pay an additional $5 million and $9 million in 2017 and 2018, respectively. These amounts are not included in the table above.

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 (e.g. the significant decline in oil prices in the second half of 2014) 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 8.

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 exploratory wells 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 charged to expense. We 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 are calculated on a depletable unit basis based significantly on estimates of quantities of proved oil and natural gas reserves. Revisions to these estimates could alter our depletion rates in the future and affect our future depletion expense.

Under the successful efforts method of accounting for oil and natural gas properties, we evaluate capitalized costs related to proved properties at least annually or upon a triggering event (such as the recent commodity price declines) 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 and 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. 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 the future cash flows based on estimates of future oil and gas production, forward commodity prices based on estimated commodity price curves 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. Each of these estimates involves judgment. As of December 31, 2014, our capitalized costs related to proved properties were approximately $5 billion for Eagle Ford, $2 billion for Wolfcamp and $1 billion for Altamont.

Leasehold acquisition costs associated with non-producing areas are assessed for impairment based on estimated drilling plans and capital expenditures relative to potential lease expirations. Our unproved property costs were approximately $0.7 billion at December 31, 2014, of which approximately $0.4 billion was associated with Wolfcamp, $0.2 billion with Altamont and $0.1 billion with Eagle Ford. Generally, economic recovery of unproved reserves in non-producing areas are not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing exploration and development of the program. Our allocation of capital to the development of unproved properties may be influenced by changes in commodity prices (e.g. the rapid decline in oil prices in the fourth quarter of 2014), the availability of drilling rigs and associated costs, and/or the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives. Due to the significant decline in oil prices, we reduced our expected capital expenditures in certain of our operating areas for 2015; however, we did not record an impairment of our unproved oil and gas properties in 2014 based on our current intent and ability to fulfill our drilling commitments prior to the expiration of associated leases. Among other factors, should oil prices not justify sufficient capital allocation to the continued development of these unproved properties, we could incur significant impairment charges of our unproved property in the future. In 2013 and from the Acquisition (May 25, 2012) to December 31, 2012, we did not record any impairments of our oil and gas properties included in continuing operations.

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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 operating 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, 2014, 62% of our total proved reserves were undeveloped and 2% 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.

Prior to the Acquisition on May 24, 2012, our predecessor accounted for oil and natural gas producing activities in accordance with the full cost method. Under the full cost accounting method, substantially all of the costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves were capitalized in full cost pools by country. These capitalized amounts included the costs of unproven properties. Under the full cost method our most critical accounting assessment was a quarterly ceiling test performed on capitalized costs for each full cost pool since many of the variables (reserves, costs and future capital) involved significant estimation. Cost pools were also evaluated periodically based on estimates of future plans and activities. Prior to the Acquisition, our predecessor recorded non-cash charges of $62 million for the period from January 1, 2012 through May 24, 2012, as a result of the decision to end exploration activities in Egypt.

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 platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, water depth, 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, 2014, our asset retirement liability was approximately $42 million.

Derivatives. We record derivative instruments at their fair values. We estimate the fair value of our derivative instruments using exchange prices, third-party pricing, 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 pricing. 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.

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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, 2014:

		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)	$ 1,045	$ 833	$ (212)	$ 1,254	$ 209

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. Our most significant judgments on tax related matters include, but are not limited to, the realization of deferred tax assets (e.g. capital loss and net operating loss carry forwards) and uncertain tax positions which involve the exercise of significant judgment which could change and impact our financial condition or results of operations. As of December 31, 2014, we had $23 million of capital loss carry forwards and $1.47 billion and $226 million of federal and state NOL carry forwards, respectively.

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.

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. 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

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- 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 5.

For information regarding changes in commodity prices and interest rates during 2014, please see Management s Discussion and Analysis of Financial Condition and Results of Operations .

Commodity Price Risk

Oil and Natural Gas 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, 2014:

		Oil and Natural Gas Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Price impact(1)	$ 1,045	$ 833	$ (212)	$ 1,254	$ 209

		Oil and Natural Gas Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Discount Rate(2)	$ 1,045	$ 1,037	$ (8)	$ 1,054	$ 9
Credit rate(3)	$ 1,045	$ 1,035	$ (10)	$ 1,050	$ 5

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

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, 2014								December 31, 2013	
	Expected Fiscal Year of Maturity of Carrying Amounts							Fair	Carrying	Fair
	2015	2016	2017	2018	2019	Thereafter	Total	Value	Amounts	Value
	(in millions)									
Fixed rate long-term debt	$	$	$	$	$ 750	$ 2,350	$ 3,100	$ 3,111	$ 3,482	$ 3,896
Average interest rate	8.6%	8.6%	8.6%	8.6%	8.9%	8.1%				
Variable rate long-term debt	$	$	$ 852	$ 496	$ 150	$	$ 1,498	$ 1,471	$ 939	$ 945
Average interest rate	3.4%	3.4%	3.5%	3.9%	4.5%	%				

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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, 2014. 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, 2014. The effectiveness of our internal control over financial reporting as of December 31, 2014 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, 2014, 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, 2014, 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, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows and changes in equity for each of the two years in the period ended December 31, 2014 (Successor), the period from

February 14, 2012 to December 31, 2012 (Successor), and the period from January 1, 2012 to May 24, 2012 (Predecessor) of EP Energy Corporation and our report dated February 20, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 20, 2015

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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, 2014 and 2013, and the related consolidated statements of income, comprehensive income, cash flows and changes in equity for each of the two years in the period ended December 31, 2014 (Successor), the period from February 14, 2012 to December 31, 2012 (Successor), and the period from January 1, 2012 to May 24, 2012 (Predecessor). 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, 2014 and 2013, and the consolidated results of its operations and its cash flows for each of the two years in the period ended December 31, 2014 (Successor), the period from February 14, 2012 to December 31, 2012 (Successor), and the period from January 1, 2012 to May 24, 2012 (Predecessor) 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, 2014, 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 20, 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 20, 2015

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per common share amounts)

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
Operating revenues				
Oil	$ 1,705	$ 1,254	$ 499	$ 310
Natural gas	284	300	216	228
NGLs	110	74	28	29
Financial derivatives	985	(52)	(62)	365
Total operating revenues	3,084	1,576	681	932
Operating expenses				
Natural gas purchases	23	25	19	
Transportation costs	100	85	48	45
Lease operating expense	193	147	63	80
General and administrative	244	229	358	69
Depreciation, depletion and amortization	875	585	188	307
Impairment and ceiling test charges	2	2	1	62
Exploration and other expense	25	41	40	
Taxes, other than income taxes	129	79	36	31
Total operating expenses	1,591	1,193	753	594
Operating income (loss)	1,493	383	(72)	338
Other income (expense)	1	(12)	(1)	(3)
Loss on extinguishment of debt	(17)	(9)	(14)	
Interest expense	(318)	(354)	(219)	(14)
Income (loss) from continuing operations before income taxes	1,159	8	(306)	321
Income tax expense	432	64		134
Income (loss) from continuing operations	727	(56)	(306)	187
Income (loss) from discontinued operations, net of tax	4	506	50	(9)
Net income (loss)	$ 731	$ 450	$ (256)	$ 178
Basic and diluted net income (loss) per common share				
Income (loss) from continuing operations	$ 3.00	$ (0.27)	$ (1.46)	
Income from discontinued operations, net of tax	0.02	2.43	0.23	
Net income (loss)	$ 3.02	$ 2.16	$ (1.23)	
Basic and diluted weighted average common shares outstanding	242	209	209	

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Year Ended December 31, 2014	Successor Year Ended December 31, 2013	February 14 to December 31, 2012	Predecessor January 1 to May 24, 2012
Net income (loss)	$ 731	$ 450	$ (256)	$ 178
Cash flow hedging activities:				
Reclassification adjustment(1)				3
Comprehensive income (loss)	$ 731	$ 450	$ (256)	$ 181

(1) Reclassification adjustments are stated net of tax. Taxes recognized for the predecessor period related to January 1, 2012 to May 24, 2012 was $2 million.

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 22	$ 51
Accounts receivable		
Customer, net of allowance of less than $1 in 2014 and 2013	234	231
Other, net of allowance of $1 for 2014 and 2013	38	40
Income tax receivable	24	3
Materials and supplies	25	20
Derivative instruments	752	47
Assets of discontinued operations		293
Deferred income taxes		28
Prepaid assets	7	10
Total current assets	1,102	723
Property, plant and equipment, at cost		
Oil and natural gas properties	10,241	8,136
Other property, plant and equipment	76	56
	10,317	8,192
Less accumulated depreciation, depletion and amortization	1,589	770
Total property, plant and equipment, net	8,728	7,422
Other assets		
Derivative instruments	297	97
Unamortized debt issue costs	90	116
Other	2	8
	389	221
Total assets	$ 10,219	$ 8,366

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 142	$ 135
Other	403	386
Income tax payable		2
Deferred income taxes	251	
Derivative instruments	1	35
Accrued interest	53	54
Asset retirement obligations	2	2
Liabilities of discontinued operations		125
Other accrued liabilities	47	63
Total current liabilities	899	802
Long-term debt	4,598	4,421
Other long-term liabilities		
Deferred income taxes	327	171
Asset retirement obligations	40	28
Other	7	7
Total non-current liabilities	4,972	4,627
Commitments and contingencies (Note 8)		
Stockholders equity		
Class A shares, $0.01 par value; 550 million shares authorized, 245 million shares issued and outstanding at December 31, 2014; 209 million shares issued and outstanding at December 31, 2013	2	
Class B shares, $0.01 par value; 0.8 million shares and 0.9 million shares authorized, issued and outstanding at December 31, 2014 and December 31, 2013		
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding		
Additional paid-in capital	3,510	2,832
Retained earnings	836	105
Total stockholders equity	4,348	2,937
Total liabilities and equity	$ 10,219	$ 8,366

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Successor			Predecessor
	Year Ended December 31, 2014	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
Cash flows from operating activities				
Net income (loss)	$ 731	$ 450	$ (256)	$ 178
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization	883	666	268	319
Gain on sale of assets	(2)	(468)		
Deferred income tax expense	435	67	1	199
Loss from unconsolidated affiliate, net of cash distributions		37	15	12
Impairment and ceiling test charges	20	46	1	62
Loss on extinguishment of debt	17	9	14	
Share-based compensation expense	13	22	17	
Non-cash portion of exploration expense	19	39	23	
Amortization of debt issuance costs	21	22	12	7
Other	2	1	1	
Asset and liability changes				
Accounts receivable	7	(50)	(73)	132
Accounts payable	13	80	66	(56)
Derivative instruments	(939)	56	281	(201)
Accrued interest		(3)	57	(1)
Other asset changes	5	(13)	(18)	(7)
Other liability changes	(39)	(1)	40	(64)
Net cash provided by operating activities	1,186	960	449	580
Cash flows from investing activities				
Capital expenditures	(2,033)	(1,924)	(877)	(636)
Proceeds from the sale of assets and investments, net of cash transferred	154	1,451	110	9
Cash paid for acquisitions, net of cash acquired	(165)	(2)	(7,126)	(1)
Net cash used in investing activities	(2,044)	(475)	(7,893)	(628)
Cash flows from financing activities				
Proceeds from issuance of long-term debt	2,455	1,880	5,825	215
Repayment of long-term debt	(2,293)	(2,190)	(1,139)	(1,065)
Proceeds from issuance of stock	669			
Distributions to members		(205)	(337)	
Contributed member equity			3,323	
Contributions from members		17		960
Debt issuance costs	(1)	(5)	(159)	
Other	(1)			
Net cash provided by (used in) financing activities	829	(503)	7,513	110

Change in cash and cash equivalents		(29)		(18)		69		62
Cash and cash equivalents								
Beginning of period		51		69				25
End of period	$	22	$	51	$	69	$	87
Supplemental cash flow information								
Interest paid, net of amounts capitalized	$	289	$	305	$	145	$	7
Income tax payments, net of refunds		26		16		2		2

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In millions)

							Stockholders Equity				
	Shares	Common Stock	Class A Stock Shares	Class A Stock Amount	Class B Stock Shares	Class B Stock Amount	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income	Total Stockholders Equity	Members Equity
Predecessor											
Balance at January 1, 2012	1,000	$		$		$	$ 4,580	$ (1,476)	$ (4)	$	$ 3,100
Contribution from parent							1,481				1,481
Other							12		3		15
Net income								178			178
Elimination of predecessor parent stockholder s equity	(1,000)						(6,073)	1,298	1		(4,774)
Balance at May 24, 2012		$		$		$	$	$	$	$	$
Successor											
Balance at February 14, 2012		$		$		$	$	$	$		$
Member contribution										$	3,323
Member distribution											(337)
Share-based compensation											18
Net loss											(256)
Balance at December 31, 2012		$		$		$	$	$	$	$	$ 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	

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 was reorganized on August 30, 2013 as a corporate holding company with a 100% equity interest in EPE Acquisition, LLC. Prior to this corporate reorganization, activities were conducted through EPE Acquisition, LLC, a holding company formed on February 14, 2012. EPE Acquisition, LLC had two classes of membership interests: Class A membership units and Class B membership units. The Class A membership units represented the full value of our capital interests, and the Class B membership units represented profits interests (for further information see Note 9). As part of the corporate reorganization, (i) all of the Class A and Class B membership units in EPE Acquisition, LLC were directly or indirectly exchanged for shares of Class A and Class B common stock, respectively of EP Energy Corporation, which have the same interests, rights and obligations of the Class A and B membership units.

EPE Acquisition, LLC had no independent operations and through its wholly-owned subsidiaries, owned the units of EP Energy LLC (which owned 100 percent of EP Energy Global LLC). On May 24, 2012, Apollo Global Management LLC (together with its subsidiaries, Apollo) and other private equity investors (collectively, the Sponsors) acquired EP Energy Global LLC and subsidiaries for approximately $7.2 billion in cash (the Acquisition) as contemplated by the merger agreement among El Paso Corporation (El Paso) and Kinder Morgan, Inc. (KMI) which is further described in Note 2. The acquired entities engage in the exploration for and the acquisition, development, and production of oil, natural gas and NGLs in the United States. Hereinafter, for periods prior to the Acquisition in 2012, the acquired entities are referred to as the predecessor for financial accounting and reporting purposes.

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. Predecessor periods reflect reclassifications to conform to EP Energy Corporation s financial statement presentation.

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. We apply the equity method of accounting where we can exert significant influence over, but do not control or direct the policies, decisions and activities of an entity.

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 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. Retrospective application of this standard is required beginning in the first quarter of 2017. We are currently evaluating the impact, if any, that this update will have on our financial statements.

Discontinued Operations. In April 2014, the FASB issued Accounting Standards Update No. 2014-08, *Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*, which alters the criteria under which assets to be disposed of are evaluated for reporting as a discontinued operation. While early adoption of this update is permitted, prospective application is required in the first quarter of 2015. Accordingly, the update will not impact our historical presentation of assets as discontinued operations. The revised standard will (i) raise the threshold for divestitures to qualify as discontinued operations and (ii) require new disclosures for both discontinued operations and material divestitures which do not qualify as discontinued operations.

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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 natural gas on a monthly basis to manage our overall natural gas production and sales. These transactions are undertaken to optimize prices we receive for our natural gas, to physically move gas to its intended sales point, or to manage firm transportation agreements. Revenue related to these transactions are recorded in natural gas sales in operating revenues and associated purchases reflected in natural gas purchases in operating expenses on our consolidated income statement.

For the years ended December 31, 2014 and 2013 and the successor period in 2012, we had two customers that individually accounted for 10 percent or more of our total revenues. The predecessor period in 2012 had three customers that individually accounted for 10 percent or more of 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, 2014 and 2013, we had less than $1 million, of restricted cash 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

Successful Efforts (Successor). In conjunction with the Acquisition, we began applying 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 by major prospect area based on our estimates or current drilling plans.

Full Cost (Predecessor). Prior to the Acquisition, the predecessor used the full cost method to account for their oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves were capitalized on a country-by-country basis. These capitalized amounts included the costs of unproved properties that were transferred into the full cost pool when the properties were determined to have proved reserves, internal costs directly related to acquisition, development and exploration activities, asset retirement costs and capitalized interest. Under the full cost method, both dry hole costs and geological and geophysical costs were capitalized into the full cost pool, which was subject to amortization and was periodically assessed for impairment through a ceiling test calculation discussed below.

Under full cost accounting, capitalized costs associated with proved reserves were amortized over the life of the proved reserves using the unit of production method. Conversely, capitalized costs associated with unproved properties were excluded from the amortizable base until these properties were evaluated or determined that the costs were impaired. On a quarterly basis, unproved property costs were transferred into the amortizable base when properties were determined to have proved reserves. If costs were determined to be impaired, the amount of any impairment was transferred to the full cost pool if an oil or natural gas reserve base exists, or was expensed if a reserve base has not yet been created. The amortizable base included future development costs; dismantlement, restoration and abandonment costs, net of estimated salvage values; and geological and geophysical costs incurred that could not be associated with specific unevaluated properties or prospects in which we owned a direct interest.

Under full cost accounting, capitalized costs in each country, net of related deferred income taxes, were limited to a ceiling based on the present value of future net revenues from proved reserves less estimated future capital expenditures, discounted at 10 percent, plus the cost of unproved oil and natural gas properties not being amortized, less related income tax effects. Prior to the Acquisition, this ceiling test calculation was performed each quarter. The prices used when performing the ceiling test were based on the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period. These prices were required to be held constant over the life of the reserves, even though actual prices of oil and natural gas changed from period to period. If total capitalized costs exceeded the ceiling, a write down of capitalized costs to the ceiling was required. Any required write-down was included as a ceiling test charge in the consolidated income statement and as an increase to accumulated depreciation, depletion and amortization on the consolidated balance sheet. The present value of future net revenues used for these ceiling test calculations excluded the impact of derivatives and the estimated future cash outflows associated with asset retirement liabilities related to proved developed reserves.

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 three to 15 years.

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.

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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 9 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 5 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. 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 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.

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Prior to the Acquisition, the predecessor s taxable income or loss was included in El Paso s U.S. federal and certain state returns and we recorded income taxes on a separate return basis in our financial statements as if we had filed separate income tax returns under our then existing structure for the periods presented in accordance with a tax sharing agreement between us and El Paso. Under that agreement El Paso paid all consolidated U.S. federal and state income tax directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, El Paso billed or was refunded for their portion of these income taxes. In certain states, the predecessor filed and paid taxes directly to the state taxing authorities.

2. Acquisitions and Divestitures

Acquisitions. On April 30, 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 current Wolfcamp acreage. The fair value of the business acquired was allocated to the underlying properties and no goodwill or bargain purchase was recorded.

On May 24, 2012, investment funds managed by Apollo (collectively, the Apollo Funds) and other investors acquired all of the equity of EP Energy Global LLC for approximately $7.2 billion. The Acquisition was funded with approximately $3.3 billion in equity contributions and the issuance of approximately $4.25 billion of debt. In conjunction with the Acquisition, a portion of the proceeds were also used to repay approximately $960 million outstanding under the predecessor s revolving credit facility at that time. See Note 7 for additional discussion of debt.

The unaudited pro forma information below for the year ended December 31, 2012 has been derived from the historical consolidated financial statements and has been prepared as though the Acquisition occurred as of the beginning of January 1, 2012. The unaudited pro forma information does not purport to represent what our results of operations would have been if such transactions had occurred on such date.

	Year ended December 31, 2012 (in millions)
Operating Revenues	$ 1,659
Net Income	143

In conjunction with the Acquisition, approximately $330 million in transaction, advisory, and other fees were incurred, of which $142 million were capitalized as debt issue costs and $15 million were capitalized as prepaid costs in other assets on our balance sheet. The remaining $173 million in fees were reflected in general and administrative expense in our consolidated income statement. Additionally, during the successor period in 2012 we recorded approximately $48 million related to transition and restructuring costs, including severance charges totaling approximately $17 million ($4 million related to divested assets). These amounts were included as general and administrative expenses in our consolidated income statement.

Discontinued Operations. We have reflected as discontinued operations certain non-core assets sold including (i) certain domestic natural gas assets in our Arklatex area and those in our 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 have reflected the domestic natural gas assets sold as discontinued operations in all successor periods and reflected our Brazilian operations as discontinued operations in all periods presented in these consolidated financial statements. For periods prior to the Acquisition, the predecessor applied the full cost method of accounting for oil and natural gas properties where capitalized costs were aggregated by country (e.g. U.S.); accordingly, these domestic assets sold did not qualify for and have not been reflected as discontinued operations in the predecessor financial statement periods.

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Summarized operating results and financial position data of our discontinued operations were as follows:

	Successor			Predecessor
	Year ended December 31, 2014	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
			(in millions)	
Operating revenues	$ 82	$ 361	$ 309	$ 46
Operating expenses				
Natural gas purchases		19	23	
Transportation costs	5	25	25	
Lease operating expense	31	92	74	16
Depreciation, depletion and amortization	8	81	80	12
Impairment and ceiling test charges(1)	18	44		
Other expense	17	53	58	20
Total operating expenses	79	314	260	48
Gain on sale of assets	2	468		
Other income (expense)	4	(2)	3	(5)
Income (loss) from discontinued operations before income taxes	9	513	52	(7)
Income tax expense	5	7	2	2
Income (loss) from discontinued operations	$ 4	$ 506	$ 50	$ (9)

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(1) During the year ended December 31, 2014, we recorded $18 million in impairment charges to impair earnings subsequent to entering into a Quota Purchase Agreement to sell our Brazil operations. During the year ended December 31, 2013, we recorded $44 million in impairment charges ($34 million to impair earnings subsequent to entering into the Quota Purchase Agreement and $10 million based on a comparison of the fair value of our Brazil operations to its underlying carrying value).

	December 31, 2013
Assets of discontinued operations	
Current assets	$ 37
Property, plant and equipment, net	246
Other non-current assets	10
Total assets of discontinued operations	$ 293
Liabilities of discontinued operations	
Accounts payable	$ 50
Other current liabilities	10
Asset retirement obligations	60
Other non-current liabilities	5
Total liabilities of discontinued operations	$ 125

Other Divestitures. In 2014, we closed the sale of certain non-core acreage in Eagle Ford in Atascosa County for approximately $28 million. No gain or loss on the sale was recorded. 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 these other domestic properties; however, in connection with entering into the sale of Four Star, we recorded a $20 million impairment in earnings from unconsolidated affiliates. See Note 10 for further discussion.

In 2012, we sold our interests in Egypt for approximately $22 million and sold oil and natural gas properties located in the Gulf of Mexico for a net purchase price of approximately $79 million. We did not record a gain or loss on any of these sales as the purchase price allocated to the assets sold was reflective of the estimated sales price of these properties and the relationship between capitalized costs and proved reserves was not altered.

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3. Income Taxes

General. As a result of the Corporate Reorganization on August 30, 2013 described in Note 1, we became a corporation subject to federal and state income taxes. Accordingly, we began recording the effects of income taxes in our financial statements 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 the Corporate Reorganization, we were a limited liability company treated as a partnership for federal and state income tax purposes. During that time, our Brazil operations continued to be subject to foreign income taxes; however, amounts related to Brazil have been reclassified in all periods as discontinued operations (see Note 2). Prior to the Acquisition (May 25, 2012), the predecessor was party to a tax accrual policy with El Paso whereby El Paso filed U.S. and certain state returns on the predecessor s behalf. Under its policy, the predecessor recorded federal and state income taxes on a separate return basis and reflected current and deferred income taxes in the financial statements through the acquisition date.

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:

	Successor			Predecessor
	Year ended December 31, 2014	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
		(in millions)		
Pretax Income (Loss)				
U.S.	$ 1,159	$ 8	$ (306)	$ 384
Foreign				(63)
	$ 1,159	$ 8	$ (306)	$ 321
Components of Income Tax Expense (Benefit)				
Current				
Federal	$	$ (2)	$	$ (62)
State				(3)
		(2)		(65)
Deferred				
Federal	415	59		188
State	17	7		11
	432	66		199
Total income tax expense	$ 432	$ 64	$	$ 134

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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, 2014	Successor Year ended December 31, 2013	February 14 to December 31, 2012 (in millions)	Predecessor January 1 to May 24, 2012
Income taxes at the statutory federal rate of 35%	$ 406	$ 3	$ (107)	$ 112
Increase (decrease)				
State income taxes, net of federal income tax effect	12	4		5
Partnership earnings not subject to tax		57	107	
Earnings from unconsolidated affiliates where we received or will receive dividends				(2)
Foreign income taxed at different rates				22
Non-deductible reorganization costs	10			
Other	4			(3)
Income tax expense	$ 432	$ 64	$	$ 134

The effective tax rate for the year ended December 31, 2014 was 37.3%, higher than the statutory rate of 35% primarily as a 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 December 2014. The effective tax rates for both the year ended December 31, 2013 and the period from February 14 to December 31, 2012, 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. The effective tax rate for the predecessor period from January 1, 2012 to May 24, 2012 was significantly higher than the statutory rate primarily due to the impact of an Egyptian non-cash charge without a corresponding tax benefit.

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, 2014	December 31, 2013
	(in millions)	
Deferred tax assets		
Net operating loss and tax credit carryovers	$ 542	$ 252
Employee benefits	1	2
Investment in partnership		11

Financial derivatives				3
Legal and other reserves		5		2
Asset retirement obligations		15		19
Transaction costs		21		21
Total deferred tax assets		584		310
Valuation allowance		(1)		
Net deferred tax assets		583		310
Deferred tax liabilities				
Property, plant and equipment		794		453
Financial derivatives		367		
Total deferred tax liabilities		1,161		453
Net deferred tax liabilities	$	578	$	143

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Unrecognized Tax Benefits. We are currently not under any U.S. or state income tax audits; however, the 2013 and 2014 tax years remain open to examination. Furthermore, pursuant to the Acquisition agreement, KMI indemnified us for any U.S. or state liability due to most of our entities having been members of the El Paso federal and state returns for any adjustments through the Acquisition date. As of December 31, 2014 there were no unrecognized tax benefits as income taxes in our financial statements in continuing operations. We did not recognize any interest and penalties related to unrecognized tax benefits (classified as income taxes in our consolidated income statements) in 2014 or 2013, nor do we have any accrued interest and penalties in our consolidated balance sheet as of December 31, 2014 and December 31, 2013.

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, 2014 (in millions):

	Expiration Period
	2031 - 2033
U.S. federal net operating loss	$ 1,466
	2016 - 2028
State net operating loss	$ 226

Net Operating Loss and Tax Credit Carryovers. In addition to our federal and state 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 all 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. The realization of our deferred tax assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences are deductible. Valuation allowances are established when necessary to reduce deferred income tax assets to the amounts we believe are more likely than not to be recovered. In evaluating our valuation allowances, we consider 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, the latter two of which involve the exercise of significant judgment. Changes to our valuation allowances could materially impact our results of operations.

As of December 31, 2014 and 2013, we had recorded $1 million and less than $1 million in valuation allowances on certain state net operating losses expiring in five years and where it was more likely than not they would not be realized. We continually monitor the realization of loss carryovers with the appropriate character of income. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances.

4. Earnings Per Share

On January 2, 2014, we completed a 62.553-for-1 stock split of our common stock. For the successor financial statement periods, 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 balance sheet and statement of changes in equity reflect the effects of the stock split. Neither earnings per share nor the effects of the stock split were presented in predecessor periods prior to the Acquisition as the predecessor operated under a different capital structure than the successor. 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. These potentially dilutive securities consist of our employee stock options and restricted stock which did not affect diluted earnings per share for the year ended December 31, 2014.

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5. Financial Instruments

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

	December 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in millions)		
Long-term debt	$ 4,598	$ 4,582	$ 4,421	$ 4,841
Derivative instruments	$ 1,048	$ 1,048	$ 109	$ 109

For the years ended December 31, 2014 and 2013, 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 7) 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 related to these instruments.

Oil and Natural Gas 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, 2014 and 2013, we had total derivative contracts of 37 MMBbls and 47 MMBbls of oil and 69 TBtu and 135 TBtu of natural gas, respectively. None of these contracts are designated as accounting hedges.

The following table reflects the volumes associated with derivative contracts entered into between January 1, 2015 and February 16, 2015.

	2016 Volumes	2017 Volumes
Oil (MBbls)		
Fixed Price Swaps		
WTI(1)	3,294	4,015
Basis Swaps		
LLS vs. WTI(2)	1,830	

(1) In February 2015, we unwound 3,294 MBbls of 2016 LLS three way collars in exchange for 3,294 MBbls of 2016 WTI fixed price swaps. No cash or other consideration was included as part of this exchange.

(2) In February 2015, we unwound 1,830 MBbls of 2016 LLS vs. Brent basis swaps in exchange for 1,830 MBbls of 2016 LLS vs. WTI basis swaps. No cash or other consideration was included as part of this exchange.

Interest Rate Derivative Instruments. We have interest rate swaps with a notional amount of $600 million that extend through April 2017 and are intended to reduce variable interest rate risk. As of December 31, 2014 and 2013, we had a net asset of $3 million and $4 million, respectively, related to interest rate derivative instruments included in our consolidated balance sheets. For the years ended December 31, 2014 and 2013 and the period from February 14 to December 31, 2012, we recorded $5 million of interest expense, $3 million of interest income and $3 million of interest expense, respectively, related to the change in fair market value and cash settlements of our interest rate derivative instruments.

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.

As of December 31, 2014 and 2013, all derivative financial instruments were classified as Level 2. Our assessment of an instrument within a level 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.

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Financial Statement Presentation. The following table presents the fair value associated with derivative financial instruments as of December 31, 2014 and 2013. 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			
			Balance Sheet Location				Balance Sheet Location	
	Gross(1) Fair Value	Impact of Netting	Current	Non-current	Gross(1) Fair Value	Impact of Netting	Current	Non-current
	(in millions)				(in millions)			
December 31, 2014								
Derivative instruments	$ 1,093	$ (44)	$ 752	$ 297	$ (45)	$ 44	$ (1)	$
December 31, 2013								
Derivative instruments	$ 164	$ (20)	$ 47	$ 97	$ (55)	$ 20	$ (35)	$

(1) Gross derivative assets are comprised primarily of $1,088 million of oil and natural gas derivatives as of December 31, 2014, $157 million of oil and natural gas derivatives as of December 31, 2013, and $5 million and $7 million of interest rate derivatives as of December 31, 2014 and December 31, 2013, respectively. Gross derivative liabilities are comprised primarily of $43 million of oil and natural gas derivatives as of December 31, 2014, $52 million of oil and natural gas derivatives as of December 31, 2013 and $2 million and $3 million of interest rate derivatives as of December 31, 2014 and December 31, 2013, respectively.

The following table presents gains and losses on financial oil and natural gas derivative instruments presented in operating revenues and dedesignated cash flow hedges of the predecessor included in accumulated other comprehensive income (in millions):

		Successor		Predecessor
	Year ended December 31, 2014	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
Gains (losses) on financial derivative instruments	$ 985	$ (52)	$ (62)	$ 365
Accumulated other comprehensive income				5

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, 2014 represent financial instruments from twelve counterparties; all of which are financial institutions that have an investment grade (minimum Standard & Poor s rating of A- or better) credit rating and are lenders associated with our $2.75 billion RBL credit facility. Subject to the terms of our $2.75 billion RBL credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the RBL Facility.

6. Property, Plant and Equipment

Oil and Natural Gas Properties. As of December 31, 2014 and 2013, we had approximately $8.7 billion and $7.4 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. At December 31, 2014 and 2013, the cost associated with unproved oil and natural gas properties totaled approximately $0.7 billion and $1.4 billion, respectively. During 2014, we transferred approximately $0.7 billion from unproved properties to proved properties. During 2014, 2013 and the period from February 14 to December 31, 2012, we recorded $18 million, $36 million and $23 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, 2014 or December 31, 2013.

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Impairment Assessment / Ceiling Test Charges. Forward commodity prices can play a significant role in determining future impairments of our proved or unproved property. Due to the significant decline in oil prices in the fourth quarter of 2014, we reviewed our proved and unproved property for impairment. In 2014, 2013 and from the Acquisition (May 25, 2012) to December 31, 2012, all periods under which we applied the successful efforts method, we did not record any impairments of our oil and gas properties included in continuing operations. Under the full cost method of accounting, the predecessor recorded a non-cash charge of approximately $62 million in the period from January 1 to May 24, 2012, as a result of the decision to exit exploration and development activities in Egypt. The charge related to unevaluated costs in that country and included approximately $2 million related to equipment. Considering the significant amount of fair value allocated to our natural gas and oil properties in conjunction with the Acquisition, sustained lower oil and natural gas prices, further price reductions or changes to our future capital and development plans due to the lower price environment could result in an impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be significant.

Leasehold acquisition costs associated with non-producing areas are assessed for impairment based on our estimated drilling plans and capital expenditures relative to potential lease expirations. Our unproved property costs were approximately $0.7 billion at December 31, 2014, of which approximately $0.4 billion was associated with Wolfcamp, $0.2 billion with Altamont and $0.1 billion with Eagle Ford. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing exploration and development activities. Our allocation of capital to the development of unproved properties may be influenced by changes in commodity prices (e.g. the rapid decline in oil prices in the fourth quarter of 2014), the availability of drilling rigs and associated costs, and/or the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives. Due to the significant decline in oil prices, we have reduced our expected capital expenditures in certain of our operating areas for 2015; however, we currently have the intent and ability to fulfill our drilling commitments prior to the expiration of the associated leases. Among other factors, should oil prices not justify sufficient capital allocation to the continued development of these unproved properties, we could incur impairment charges of our unproved property, and such charges could be significant.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We incur 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 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 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:

	2014	2013
	(in millions)	
Net asset retirement liability at January 1	$ 30	$ 24
Liabilities incurred	10	6
Liabilities settled	(2)	(2)
Accretion expense	3	2
Changes in estimate	2	1
Property sales		(1)
Other	(1)	
Net asset retirement liability at December 31	$ 42	$ 30

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 year ended December 31, 2014 and 2013 was approximately $21 million and $19 million, respectively. For the period from February 14 to December 31, 2012, capitalized interest was $12 million, and for the predecessor period from January 1, 2012 to May 24, 2012, it was $4 million.

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7. Long Term Debt

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

	Interest Rate	December 31, 2014	December 31, 2013
		(in millions)	
EP Energy LLC			
$2.75 billion RBL credit facility - due May 24, 2017	Variable	$ 852	$ 295
$750 million senior secured term loan - due May 24, 2018(1)(3)	Variable	496	495
$400 million senior secured term loan - due April 30, 2019(2)(3)	Variable	150	149
$750 million senior secured notes - due May 1, 2019(3)	6.875%	750	750
$2.0 billion senior unsecured notes - due May 1, 2020	9.375%	2,000	2,000
$350 million senior unsecured notes - due September 1, 2022	7.75%	350	350
EPE Holdings LLC			
$350 million senior PIK toggle note - due December 15, 2017(4)	8.125%/8.875%		382
Total		$ 4,598	$ 4,421

(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, 2014 and 2013, 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, 2014 and 2013, the effective interest rate for the term loan was 4.50%.

(3) The term loans and secured notes 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.

(4) In 2014, we repaid our senior PIK toggle note with proceeds from our initial public offering.

As of December 31, 2014 and 2013, we had $90 million and $116 million, respectively, in deferred financing costs on our consolidated balance sheets. During 2014, 2013, the period from February 14 to December 31, 2012, and the predecessor period from January 1 to May 24, 2012, we amortized $21 million, $22 million, $12 million, and $7 million, respectively, of deferred financing costs in interest expense.

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. During 2013 and the period from February 14 to December 31, 2012, we recorded $9 million and $14 million in losses on the extinguishment of debt. The 2013 losses were associated with the pro-rata portion of deferred financing costs written off in conjunction with (i) the repayment of approximately $250 million under each of our $750 million and $400 million term loans, (ii) our $750 million term loan re-pricing in May 2013 and (iii) the semi-annual redetermination of our RBL Facility in March 2013. The 2012 losses were associated with the pro-rata portion of deferred financing costs written off, debt discount and call premiums paid related to lenders who exited or reduced their loan commitments in conjunction with our $750 million term loan repricing.

$2.75 Billion Reserve-based Loan (RBL). 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, 2014, we had $852 million of outstanding borrowings and approximately $83 million of letters of credit issued under the facility, leaving $1.8 billion of remaining capacity available. Listed below is a further description of our credit facility as of December 31, 2014:

Credit Facility	**Maturity Date**	**Interest Rate**	**Commitment fees**
$2.75 billion RBL	May 24, 2017	LIBOR + 1.75%(1) 1.75% for LCs	0.375% commitment fee on unused capacity

(1) Based on our December 31, 2014 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.

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 October 2014, we completed our semi-annual redetermination, increasing the borrowing base of our RBL Facility to $2.75 billion. Our next redetermination date is in April 2015. Downward revisions of our oil and natural gas reserves due to future declines in commodity prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a redetermination of the borrowing base and could negatively impact our ability to borrow funds under the RBL Facility in the future.

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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, 2014, we were in compliance with our debt covenants.

8. 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 of these matters, 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 related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of December 31, 2014, we had approximately $2 million accrued for all outstanding legal matters.

Southeast Louisiana Flood Protection Authority v. EP Energy Management, L.L.C. On July 24, 2013, the levee authority for New Orleans and surrounds (the Authority) filed suit against 97 oil, gas and pipeline companies, seeking (among other relief) restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit, which does not specify an amount of damages, was filed in Louisiana state court in New Orleans but then removed to the U.S. District Court for the Eastern District of Louisiana (the District Court). The Louisiana State Legislature has passed legislation that could result in dismissal of the lawsuit. Our subsidiary, EP Energy Management, L.L.C., is named as successor to Colorado Oil Company, Inc. and Gas Producing Enterprises as operators of five wells from the mid-1970s to 1980. On February 13, 2015, the District Court dismissed the case for failure to state a claim finding that the defendants had no duty to the Authority. The Authority will have 30 days from a final judgment to appeal to the U.S. Court of Appeals for the Fifth Circuit.

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, 2014, we had approximately $8 million accrued related to these indemnifications and other matters.

Sales Tax Audits. As a result of sales and use tax audits during 2010, the state of Texas asserted additional taxes plus penalties and interest for the audit period 2001-2008 for two of our operating entities. During 2013, we settled the last of these audits for approximately $3 million, including penalties and fees. As a result of the settlement, we recorded a reduction in taxes, other than income taxes in our consolidated income statement of approximately $13 million.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. 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, 2014, we had accrued 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 exposure could be as high as $1 million. 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.

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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. There have also been various legislative and regulatory proposals and final rules at the federal and state levels to address emissions from power plants and industrial boilers, which will generally favor the use of natural gas over other fossil fuels such as coal. It remains uncertain what regulations or amended final rules will ultimately be adopted and when they will be adopted. As part of the White House s Climate Action Plan Strategy to Reduce Methane Emissions, the EPA has announced it will propose additional regulations in 2015 for the oil and gas industry addressing methane and other emissions. Further, the Bureau of Land Management is expected to propose additional regulations for public lands in 2015, and the Pipeline and Hazardous Materials Safety Administration is expected to propose new standards in 2015 for natural gas pipelines. Any regulations regarding GHG emissions would likely increase our costs of compliance by potentially delaying 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.

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. On May 22, 2014, the EPA extended this deadline to March 2, 2016, during which time the EPA anticipates separate rulemaking to create general permits for true minor sources in the oil and gas production industry. 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, the Department of the Interior 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.

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, 2014, 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.

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.

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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, 2014, were as follows:

Year Ending December 31,	**Operating Leases (in millions)**
2015	$ 11
2016	12
2017	7
Total	$ 30

Subsequent to December 31, 2014, we extended certain office leases and will pay an additional $5 million and $9 million in 2017 and 2018, respectively. These amounts are not included in the table above.

Rental expense for the successor periods for the years ended December 31, 2014 and 2013, and for the period from February 14 to December 31, 2012 was $13 million, $13 million and $10 million, respectively. Rental expense for the predecessor period from January 1, 2012 to May 24, 2012 was $1 million.

Other Commercial Commitments

At December 31, 2014, we have various commercial commitments totaling $809 million primarily related to commitments and contracts associated with volume and transportation, drilling rigs, completion activities and seismic activities. Our annual obligations under these arrangements are $184 million in 2015, $185 million in 2016, $83 million in 2017, $83 million in 2018, and $274 million thereafter.

9. Long-Term Incentive Compensation / Retirement 401(k) 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 11,179,603 shares remaining available for issuance as of December 31, 2014. In addition, in conjunction with the Acquisition in 2012, certain employees received other LTI awards based on their purchased equity interests including (i) Class A matching units (subsequently converted into common shares upon our Corporate Reorganization) and (ii) a guaranteed bonus as well as (iii) 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, 2014 is presented below:

Non-vested at December 31, 2013		$	
Granted	1,131,154		19.80
Vested	(1,929)		19.82
Forfeited	(95,831)		19.82
Non-vested at December 31, 2014	1,033,394	$	19.80

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During 2014 we recognized approximately $5 million of pre-tax compensation expense and recorded income tax benefits of $2 million on our restricted share awards. The total unrecognized compensation cost related to these arrangements at December 31, 2014 was approximately $14 million, which is expected to be recognized over a weighted average period of 2 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, 2014 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, 2013				
Granted	253,740	$ 19.82		
Forfeited or canceled	(34,388)	19.82		
Outstanding at December 31, 2014	219,352	$ 19.82	9.25	

During 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, 2014 was approximately $2 million, which is expected to be recognized over a weighted average period of 4 years. There were no options exercised during the year.

Fair Value Assumptions. 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 years 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 grants in 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 use 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 2012 and 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. These cash-based LTI awards have a three-year vesting schedule (50% vesting at the end of the first year, and 25% vesting at the end of each of the succeeding two years). These performance based cash incentive awards 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 that will be amortized primarily on an accelerated basis over a three-year vesting period. For the years ended December 31, 2014 and 2013 and the period from February 14 to December 31, 2012, we recorded approximately $8 million, $16 million and $8 million, respectively, in expense related to these awards. As of December 31, 2014, we had unrecognized compensation expense of $3 million related to these awards which we will recognize in 2015.

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

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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 four 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, 2014 and 2013 and the period from February 14 to December 31, 2012, we recognized approximately $2 million, $6 million and $11 million, respectively, as compensation expense related to both of these awards. As of December 31, 2014, we had unrecognized compensation expense of $4 million related to the matching Class A unit grants, of which we will recognize $3 million in 2015 and the remainder 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, 2014 and 2013 and the period from February 14 to December 31, 2012, we recognized approximately $6 million, $19 million and $15 million, respectively, as compensation expense related to these awards. As of December 31, 2014, we had unrecognized compensation expense of $9 million. Of this amount, we will recognize $6 million in 2015 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.

Retirement 401(k) 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 contribution plan. During 2014 and 2013 and the period from February 14 to December 31, 2012, we had contributed $11 million, $12 million and $7 million, respectively, of matching and non-elective employer contributions.

10. Investments in Unconsolidated Affiliate

As discussed in Note 2, in September 2013, we sold our equity investment in Four Star, for net proceeds of $183 million and recorded an impairment of $20 million based on comparison of net proceeds received to the underlying carrying value of our investment. Our consolidated income statement in 2012 and 2013 reflects (i) our share of net earnings directly attributable to Four Star, (ii) impairments of our investment and (iii) prior to its sale, the amortization of the excess of the carrying value of our investment relative to the underlying equity in the net assets of the entity.

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Below is summarized financial information of the operating results of Four Star.

	Successor		Predecessor
	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012
		(in millions)	
Operating revenues	$ 142	$ 105	$ 75
Operating expenses	94	87	58
Net income	30	11	11

In addition to recording our share of Four Star operating results, we amortized the excess of our investment in Four Star prior to its sale over the underlying equity in its net assets using the unit-of-production method over the life of our estimate of Four Star s oil and natural gas reserves. Amortization of our investment for the year ended December 31, 2013 and for the period of February 14 to December 31, 2012, was $8 million and $7 million, respectively. Amortization of our investment for the predecessor period from January 1 to May 24, 2012 was $12 million. Our financial results related to our equity investment in Four Star were included as other income (expense) on our consolidated income statements.

For the year ended December 31, 2013 and the period from February 14 to December 31, 2012, we received dividends from Four Star of approximately $24 million and $13 million, respectively. Dividends received from Four Star for the predecessor period from January 1 to May 24, 2012 was $8 million.

11. Related Party Transactions

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

Transaction Fee Agreement. Following the Acquisition, we were subject to a transaction fee agreement with certain of our Sponsors (the Service Providers) for the provision of certain structuring, financial, investment banking and other similar advisory services. At the time of the Acquisition, we paid one-time transaction fees of $71.5 million (recorded as general and administrative expense in our consolidated income statement) to the Service Providers in the aggregate in exchange for services rendered in connection with structuring, arranging the financing and performing other services. On December 20, 2013, the Transaction Fee Agreement was amended and restated in its entirety pursuant to which the requirement to pay an additional transaction fee to the Service Providers under the agreement was eliminated (and, as described below, an additional fee became payable under the amended and restated Management Fee Agreement). The amended and restated Transaction Fee Agreement terminated automatically in accordance with its terms upon the closing of our initial public offering.

Management Fee Agreement. In January 2014, we paid a quarterly management fee of $6.25 million to our private equity investors (affiliates of Apollo Management LLC (Apollo), Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, collectively the Sponsors). Additionally, subject to the terms and conditions of the amended and restated Management Fee Agreement, 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. The amended and restated Management Fee Agreement, including the obligation to pay the quarterly management fee, terminated automatically in accordance with its terms upon the closing of our initial public offering.

Affiliate Supply Agreement. For the year ended December 31, 2014, we have recorded approximately $112 million in capital expenditures for amounts provided under two supply agreements entered into with an Apollo affiliate to provide certain fracturing materials for our Eagle Ford drilling operations.

Related Party Transactions Prior to the Acquisition. At the time of the Acquisition, El Paso made total contributions of approximately $1.5 billion to the predecessor including a non-cash contribution of approximately $0.5 billion to satisfy its then current and deferred income tax balances and a cash contribution to facilitate repayment of approximately $960 million of then outstanding debt of the predecessor under its revolving credit facility. Additionally, prior to the completion of the Acquisition, the predecessor entered into transactions during the ordinary course of conducting its business with affiliates of El Paso, primarily related to the sale, transportation and hedging of its oil, natural gas and NGLs production.

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The agreements noted below ceased on the date of Acquisition and included the following services:

- *General*. El Paso billed the predecessor directly for certain general and administrative costs and allocated a portion of its general and administrative costs. The allocation was based on the estimated level of resources devoted to its operations and the relative size of its earnings before interest and taxes, gross property and payroll. These expenses were primarily related to management, legal, financial, tax, consultative, administrative and other services, including employee benefits, pension benefits, annual incentive bonuses, rent, insurance, and information technology. El Paso also billed the predecessor directly for compensation expense related to certain stock-based compensation awards granted directly to the predecessor s employees, and allocated to the predecessor a proportionate share of El Paso s corporate compensation expense. Compensation cost associated with the acceleration of vesting as a result of the merger between El Paso and KMI was assumed by El Paso and KMI and is not reflected in the predecessor financial statements.

- *Pension and Retirement Benefits*. El Paso maintained a primary pension plan, the El Paso Corporation Pension Plan, a defined benefit plan covering substantially all of our employees prior to the Acquisition and providing benefits under a cash balance formula. El Paso also maintained a defined contribution plan covering all of our employees prior to the Acquisition. El Paso matched 75% of participant basic contributions up to 6 percent of eligible compensation and made additional discretionary matching contributions. El Paso was responsible for benefits accrued under these plans and allocated related costs.

- *Other Post-Retirement Benefits.* El Paso provided limited post-retirement life insurance benefits for current and retired employees prior to the Acquisition. El Paso was responsible for benefits accrued under its plan and allocated the related costs to its affiliates.

- *Marketing.* Prior to the completion of the Acquisition, the predecessor sold natural gas primarily to El Paso Marketing at spot market prices. The predecessor was also a party to a hedging contract with El Paso Marketing. Realized gains and losses on these hedges were included in operating revenues.

- *Transportation and Related Services.* Prior to the completion of the Acquisition, the predecessor contracted for services with El Paso s regulated interstate pipelines that provided transportation and related services for natural gas production.

The following table shows revenues and charges to/from affiliates for the following predecessor period (in millions):

		January 1 to May 24, 2012
Operating revenues	$	143
Operating expenses		44
Reimbursements of operating expenses		

- *Income Taxes.* Prior to the Acquisition, El Paso filed consolidated U.S. federal and certain state tax returns which included the predecessor s taxable income. See Note 3 for additional information on income tax related matters.

- *Cash Management Program.* Prior to the Acquisition, our predecessor participated in El Paso s cash management program which matched short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowings from outside sources.

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Supplemental Selected Quarterly Financial Information (Unaudited)

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

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

2013	**March 31**	**June 30**	**September 30**	**December 31**
Operating revenues				
Physical sales	$ 345	$ 390	$ 456	$ 437
Financial derivatives	(131)	166	(142)	55
Operating (loss) income	(50)	272		161
Income tax expense			30	34
(Loss) income from continuing operations	(141)	189	(146)	42
Net (loss) income	(114)	201	310	53
Basic and diluted net (loss) income per common share(1)				
(Loss) income from continuing operations	$ (0.68)	$ 0.90	$ (0.70)	$ 0.21
Net (loss) income	$ (0.55)	$ 0.96	$ 1.49	$ 0.26

(1) 2013 amounts reflect different share count, corporate structure and tax treatment.

Below are additional significant items affecting comparability of amounts reported in the respective periods of 2014 and 2013:

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.

September 30, 2013. We recorded a $455 million gain on sale of assets from discontinued operations.

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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 and Egypt that were sold in 2012.

All periods included for capitalized costs, total costs incurred and results in operations reflect our Brazil operations as discontinued operations. The successor periods (periods after May 25, 2012) also reflect domestic natural gas assets sold, including Arklatex, South Louisiana Wilcox, CBM and South Texas assets as discontinued operations. Predecessor periods do not reflect these domestic sales as discontinued operations due to the application of the full cost method of accounting prior to the Acquisition. 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):

		2014		2013
Oil and natural gas properties	$	10,241	$	8,112
Less accumulated depreciation, depletion and amortization		1,560		744
Net capitalized costs	$	8,681	$	7,368

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Total Costs Incurred. Costs incurred in oil and natural gas producing activities, whether capitalized or expensed, were as follows for the successor periods for the years ended December 31, 2014 and 2013, the period from February 14, 2012 to December 31, 2012 and the predecessor period from January 1, 2012 to May 24, 2012 (in millions):

	U.S.
Successor	
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
Consolidated from February 14, 2012 to December 31, 2012:	
Property acquisition costs	
Proved properties	$
Unproved properties	19
Exploration costs (capitalized and expensed)	107
Development costs	792
Costs expended	918
Asset retirement obligation costs	3
Total costs incurred	$ 921
Unconsolidated Affiliate from February 14, 2012 to December 31, 2012:	
Development costs expended**(1)**	$ 2

	U.S.	Egypt(2)	Worldwide
Predecessor			
Consolidated from January 1, 2012 to May 24, 2012:			
Property acquisition costs			
Proved properties	$	$	$
Unproved properties	31		31
Exploration costs	79	2	81
Development costs	503		503
Costs expended	613	2	615
Asset retirement obligation costs	21		21
Total costs incurred	$ 634	$ 2	$ 636
Unconsolidated Affiliate from January 1, 2012 to May 24, 2012:			
Development costs expended**(1)**	$ 3	$	$ 3

(1) Amounts represent our approximate 49% equity interest in the underlying costs incurred by Four Star. We sold our interest in Four Star in September 2013.

(2) In June of 2012 we sold our Egyptian oil and gas properties.

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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 $38 million, $37 million and $25 million for the years ended December 31, 2014 and 2013 and for the period from February 14, 2012 to December 31, 2012, and capitalized interest of $21 million, $19 million and $12 million for the same periods.

Pursuant to the full cost method of accounting, the predecessor capitalized certain general and administrative expenses directly related to property acquisition, exploration and development activities and interest costs incurred and attributable to unproved oil and natural gas properties and major development projects of oil and natural gas properties. The table above includes capitalized internal general and administrative costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves of $31 million for the period from January 1, 2012 to May 24, 2012. The predecessor also capitalized interest of $4 million for the period from January 1, 2012 to May 24, 2012.

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, 2014 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 2014 proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2014 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, 2014. In connection with its audit, Ryder Scott reviewed 94% (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, 91% 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, 2014 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.

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	Year Ended December 31, 2014(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	1,070	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(2)	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 using first day 12-month average prices of $94.99 per barrel of oil (WTI) and $4.34 per MMBtu of natural gas (Henry Hub).

(2) 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 using first day 12-month average prices of $96.94 per barrel of oil (WTI) and $3.67 per MMBtu of natural gas (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 .3 MMBoe to reflect an adjustment made to the prices used to calculate proved reserves.

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	Year Ended December 31, 2012(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	2,566	177,801	14,245	619.7	81	2,269	15.8	635.5
Revisions due to prices	(718)	(604)	(371)	(120.6)		1		(120.6)
Revisions other than prices	55	(18,451)	10,267	1.1	(3)	288	(0.3)	0.8
Extensions and discoveries(2)	119	109,125	13,450	142.4				142.4
Purchases of reserves in place		3	2					
Sales of reserves in place	(72)	(2,501)	(1,358)	(15.9)				(15.9)
Production	(223)	(9,131)	(1,904)	(48.2)	(10)	(406)	(2.1)	(50.3)
End of year	1,727	256,242	34,331	578.5	68	2,152	13.4	591.9
Proved developed reserves:								
Beginning of year	1,488	46,797	5,168	300.0	81	2,269	15.8	315.8
End of year	1,189	55,924	9,080	263.2	68	2,152	13.3	276.5
Proved undeveloped reserves:								
Beginning of year	1,078	131,004	9,077	319.7				319.7
End of year	538	200,318	25,251	315.2				315.2
Unconsolidated Affiliate Four Star								
Proved developed and undeveloped reserves								
Beginning of year	135	1,569	4,908	29.0				29.0
Revisions due to prices	(13)	(37)	(310)	(2.5)				(2.5)
Revisions other than prices	19	803	1,710	5.8				5.8
Extensions and discoveries(2)	25	95	137	4.3				4.3
Production	(16)	(282)	(478)	(3.5)				(3.5)
End of year	150	2,148	5,967	33.1				33.1
Proved developed reserves:								
Beginning of year	116	1,519	4,066	24.9				24.9
End of year	140	2,111	5,289	30.9				30.9
Proved undeveloped reserves:								
Beginning of year	19	49	842	4.0				4.0

End of year	10	37	678	2.4				2.4
Total Combined								
Proved developed reserves:								
Beginning of year	1,604	48,316	9,234	324.9	81	2,269	15.8	340.7
End of year	1,329	58,035	14,369	294.1	68	2,152	13.3	307.4
Proved undeveloped reserves:								
Beginning of year	1,097	131,053	9,919	323.7				323.7
End of year	548	200,355	25,929	317.6				317.6

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(1) Proved reserves were evaluated using first day 12-month average prices of $94.61 per barrel of oil (WTI) and $2.76 per MMBtu of natural gas (Henry Hub).

(2) Of the 146.7 MMBoe of combined extensions and discoveries, 6.2 MMBoe are in the Altamont area, 110.7 MMBoe are in the Eagle Ford Shale and 23.5 are in the Wolfcamp Shale. There were no extensions or discoveries in Brazil. Of the 146.7 MMBoe of extensions and discoveries, 122.8 MMBoe were liquids representing 84% of EP Energy s total extensions and discoveries.

In accordance with SEC Regulation S-X, Rule 4-10 as amended, we use the12-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, 2014 was $94.99 per barrel of oil (WTI) and $4.34 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, 2014, there have been no major discoveries, favorable or otherwise, that may be considered to have caused a significant change in our estimated proved reserves at December 31, 2014.

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Results of Operations. Results of operations for oil and natural gas producing activities for the successor periods for the years ended December 31, 2014 and 2013 and from February 14, 2012 to December 31, 2012 and the predecessor period from January 1, 2012 to May 24, 2012 (in millions):

		U.S.
Successor		
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(5)		(18)
		26
Income tax expense		(8)
Results of operations from producing activities	$	18
Consolidated from February 14, 2012 to December 31, 2012:		
Net Revenues(1) Sales to external customers	$	743
Costs of products and services		(82)
Production costs(2)		(100)
Depreciation, depletion and amortization(3)		(183)
Exploration expense		(40)
Results of operations from producing activities	$	338
Unconsolidated Affiliate Four Star from February 14, 2012 to December 31, 2012(4):		
Net Revenues Sales to external customers	$	52
Costs of products and services		(3)
Production costs(2)		(24)
Depreciation, depletion and amortization(5)		(16)
		9
Income tax expense		(3)
Results of operations from producing activities	$	6

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	U.S.	Egypt(5)	Worldwide
Predecessor			
Consolidated from January 1, 2012 to May 24, 2012:			
Net Revenues(1)			
Sales to external customers	$ 424	$	$ 424
Affiliated sales	143		143
Total	567		567
Costs of products and services	(49)		(49)
Production costs(2)	(115)		(115)
Impairments and ceiling test charges		(60)	(60)
Depreciation, depletion and amortization(3)	(301)		(301)
	102	(60)	42
Income tax expense	(37)		(37)
Results of operations from producing activities	$ 65	$ (60)	$ 5
Unconsolidated Affiliate Four Star from January 1, 2012 to May 24, 2012(4)*:*			
Net Revenues Sales to external customers	$ 35	$	$ 35
Costs of products and services	(1)		(1)
Production costs(2)	(15)		(15)
Depreciation, depletion and amortization(6)	(11)		(11)
	8		8
Income tax expense	(3)		(3)
Results of operations from producing activities	$ 5	$	$ 5

(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, $4 million and $9 million for the years ended December 31, 2014 and 2013 and the period from February 14, 2012 to December 31, 2012, $5 million for the predecessor period from January 1, 2012 to May 24, 2012, respectively.

(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, $7 million for the period from February 14, 2012 to December 31, 2012 and $12 million for the predecessor period from January 1, 2012 to May 24, 2012 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 table above.

(5) In June of 2012 we sold our Egyptian oil and gas properties.

(6) Includes accretion expense on asset retirement obligations of $1 million for the period from February 14, 2012 to December 31, 2012 and $1 million for the predecessor period from January 1, 2012 to May 24, 2012, respectively.

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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.
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
2012 Consolidated:						
Future cash inflows(1)	$	28,488	$	701	$	29,189
Future production costs		(7,487)		(415)		(7,902)
Future development costs		(6,189)		(71)		(6,260)
Future income tax expenses(3)				(14)		(14)
Future net cash flows		14,812		201		15,013
10% annual discount for estimated timing of cash flows		(7,913)		(39)		(7,952)
Standardized measure of discounted future net cash flows	$	6,899	$	162	$	7,061
2012 Unconsolidated Affiliate Four Star(4):						
Future cash inflows(1)	$	828	$		$	828
Future production costs		(392)				(392)
Future development costs		(54)				(54)
Future income tax expenses		(139)				(139)
Future net cash flows		243				243
10% annual discount for estimated timing of cash flows		(107)				(107)
Standardized measure of discounted future net cash flows	$	136	$		$	136

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2014, 2013 and 2012. 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.

(3) For the year ended December 31, 2012, there were no U.S. future income taxes because the company was not subject to federal income taxes.

(4) Amounts represent our approximate 49% equity interest in Four Star which was sold in September 2013.

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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):

	Years Ended December 31,(1)		
	2014	2013	2012
Consolidated:			
Sales and transfers of oil and natural gas produced net of production costs	$ (1,785)	$ (1,493)	$ (1,433)
Net changes in prices and production costs	(762)	(745)	(871)
Extensions, discoveries and improved recovery, less related costs	1,728	2,626	2,539
Changes in estimated future development costs	63	(10)	978
Previously estimated development costs incurred during the period	1,192	679	587
Revision of previous quantity estimates	441	447	(1,863)
Accretion of discount	833	796	731
Net change in income taxes	384	(2,864)	1,683
Purchase of reserves in place	137		
Sales of reserves in place	(229)	(886)	(296)
Change in production rates, timing and other	(613)	27	(210)
Net change	$ 1,389	$ (1,423)	$ 1,845
Unconsolidated Affiliate Four Star: (2)			
Sales and transfers of oil and natural gas produced net of production costs		$ (41)	$ (48)
Net changes in prices and production costs		6	(112)
Extensions, discoveries and improved recovery, less related costs			25
Changes in estimated future development costs		25	5
Revision of previous quantity estimates		10	19
Accretion of discount		18	22
Net change in income taxes		68	39
Sales of reserves in place		(260)	
Change in production rates, timing and other		38	(8)
Net change		$ (136)	$ (58)
Representative NYMEX prices:(3)			
Oil (Bbl)	$ 94.99	$ 96.94	$ 94.61
Natural gas (MMBtu)	$ 4.34	$ 3.67	$ 2.76
Aggregate International prices:(3)			
Oil (Bbl)		$ 108.02	$ 111.21
Natural gas (MMBtu)		$ 6.31	$ 6.55

(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, 2014, 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, 2014. 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 2014 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 2015 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 2015 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 2015 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 2015 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 2015 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	109

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 20th day of February 2015.

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 20, 2015
/s/ Dane E. Whitehead Dane E. Whitehead	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 20, 2015
/s/ Francis C. Olmsted III Francis C. Olmsted III	Vice President and Controller (Principal Accounting Officer)	February 20, 2015
/s/ Ralph Alexander Ralph Alexander	Director	February 20, 2015
/s/ Gregory A. Beard Gregory A. Beard	Director	February 20, 2015
/s/ Wilson B. Handler Wilson B. Handler	Director	February 20, 2015
/s/ John J. Hannan John J. Hannan	Director	February 20, 2015
/s/ Michael S. Helfer Michael S. Helfer	Director	February 20, 2015
/s/ Thomas R. Hix Thomas R. Hix	Director	February 20, 2015

/s/ Ilrae Park Ilrae Park	Director	February 20, 2015
/s/ Keith O. Rattie Keith O. Rattie	Director	February 20, 2015
/s/ Robert M. Tichio Robert M. Tichio	Director	February 20, 2015
/s/ Donald A. Wagner Donald A. Wagner	Director	February 20, 2015
/s/ Rakesh Wilson Rakesh Wilson	Director	February 20, 2015

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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 6.875% Senior Secured Notes due 2019 (Exhibit 4.1 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 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).
4.3	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).
4.4	Indenture, dated as of December 21, 2012, between EPE Holdings LLC and EP Energy Bondco Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 8.125%/8.875% Senior PIK Toggle Notes due 2017 (Exhibit 4.4 to the Company s Registration Statement on Form S-1, filed with the SEC on September 4, 2013).
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 6.875% Senior Secured Notes due 2019 (Exhibit 4.4 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 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).
4.7	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

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Exhibit No.	Exhibit Description
	September 11, 2012).
4.8	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).
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	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).
10.9*	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).
10.10	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).
10.11	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).

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Exhibit No.	Exhibit Description
10.12	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).
10.13	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).
10.14	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).
10.15	Pledge Agreement, dated as of May 24, 2012, by and among EP Energy Brazil, L.L.C. (f/k/a El Paso Brazil, L.L.C.), as Pledgor, and Citibank, N.A., as Collateral Agent (Exhibit 10.11 to EP Energy LLC s Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.16	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).
10.17	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).
10.18	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).
10.19	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).
10.20	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).
10.21	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).
10.22	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).
10.23	Amended and Restated Transaction Fee Agreement, dated as of December 20, 2013, among EP Energy Corporation, EP Energy Global LLC, EPE Acquisition, LLC, Apollo Global Securities, LLC, Riverstone V Everest Holdings, L.P., Access Industries, Inc. and Korea National Oil Corporation (Exhibit 10.22 to Amendment No. 4 to the Company s Registration Statement on Form S-1, filed with the SEC on January 6, 2014).
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

Exhibit No.	Exhibit Description
	Statement on Form S-4, filed with the SEC on September 11, 2012).
10.26+	Employment Agreement dated May 24, 2012 for John D. Jensen (Exhibit 10.19 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 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).
10.28+	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).
10.29+	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).
10.30+*	Employment Agreement dated May 24, 2012 for Joan M. Gallagher.
10.31+	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).
10.32+	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).
10.33+	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).
10.34+	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).
10.35+	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).
10.36+	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).
10.37+	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).
10.38+	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).
10.39+	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).
10.40+	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).
10.41+	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).
10.42+	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).

10.43	Stockholders Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party

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Exhibit No.	Exhibit Description
	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).
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, 2014.
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.