EP Energy Corp
Form 10-K
February 28, 2014
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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, 2013

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 333-183815

EP Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

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

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 o No o.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this

Form 10-K or any amendment to this Form 10-K. x

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

Large accelerated filer o	Accelerated filer 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.

As of June 30, 2013, the last business day of the registrant s most recently completed second fiscal quarter, the registrant s equity was not listed on any domestic exchange or over-the-counter market. The registrant s Class A Common Stock began trading on the NYSE on January 17, 2014.

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 20, 2014: 243,877,539

Class B Common Stock, par value $0.01 per share. Shares outstanding as of February 20, 2014: 872,586

Documents Incorporated by Reference: None

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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
Bcfe	=	billion cubic feet of natural gas equivalents
Boe	=	barrel of oil equivalent
CBM	=	coal bed methane
Gal	=	gallons
LNG	=	liquified natural gas
MBoe	=	thousand barrels of oil equivalent
MBbls	=	thousand barrels
Mcf	=	thousand cubic feet
Mcfe	=	thousand cubic feet of natural gas equivalents
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

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;
- 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;
- changes in commodity prices and basis differentials for oil and natural gas;
- 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;
- political and currency risks associated with our international operations;
- competition; and

- the other factors described under Item 1A, Risk Factors, on pages 17 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 Report 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) was formed on August 30, 2013, and 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. Prior to August 30, 2013, EP Energy conducted its activities through EPE Acquisition, LLC, and its predecessor entities and their subsidiaries. On May 24, 2012, affiliates of Apollo Global Management LLC (together with its subsidiares, Apollo), Riverstone Holdings LLC (Riverstone), Access Industries (Access) and Korea National Oil Corporation (KNOC) (collectively, the Sponsors) and other co-investors acquired EP Energy Global LLC and its subsidiaries for approximately $7.2 billion in cash as contemplated by the merger agreement among El Paso Corporation (El Paso) and Kinder Morgan, Inc. (KMI). Hereinafter, the acquisition of EP Energy Global LLC 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 core areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), the Altamont field in the Uinta Basin in northeastern Utah and the Haynesville Shale (North Louisiana). We also operate in other non-core areas primarily in Texas and Louisiana. In our core areas, we have identified approximately 5,170 drilling locations (including 968 drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013), of which approximately 97% are oil wells. At current activity levels, this represents approximately 23 years of drilling inventory. As of December 31, 2013, we had proved reserves of 547.5 MMBoe (54% oil and 67% liquids) and for the three months ended December 31, 2013, we had average net daily production of 87,304 Boe/d (49% oil and 58% liquids).

Each of our core 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 440,000 net (613,000 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 continuing production growth of 15% and 55%, respectively, from December 31, 2012 to December 31, 2013.

During 2013, we divested non-core domestic natural gas assets and an equity investment for a total consideration of approximately $1.5 billion. We also entered into a Quota Purchase Agreement relating to the sale of our Brazil operations, which is expected to close in 2014. All periods present our Brazil operations as discontinued operations, and accordingly its operations are excluded from the discussion in this section. Periods after the Acquisition in May 2012, referred to as successor periods also present domestic natural gas assets sold, including the CBM and South Texas assets and the majority of our Arklatex assets, as discontinued operations, and accordingly those operations are excluded from the discussion in this section. The predecessor periods present our domestic natural gas assets sold in 2013 and our Gulf of Mexico assets sold in 2012 as divested assets.

As a result of these asset sales, we are a higher-growth, 100% onshore U.S., oil-weighted company with a large inventory of high-return, low-risk drilling locations. We intend to continue developing our oil-weighted assets, which offer the best rates of return in our portfolio in the current commodity price environment. In addition, our Haynesville Shale position is 100% held-by-production, which gives us the flexibility to allocate capital to this natural gas-weighted asset in the future.

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The following table provides a summary of our oil, natural gas and NGLs reserves and production data as of December 31, 2013 for each of our ongoing areas of operation.

	Estimated Proved Reserves						Average
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Liquids (%)	Proved Developed (%)	Net Daily Production (MBoe/d)
Core Areas							
Eagle Ford Shale	173.6	54.9	376.6	291.2	78%	24%	36.6
Wolfcamp Shale	45.9	19.8	115.0	84.9	77%	25%	5.5
Altamont	72.0		149.6	96.9	74%	39%	11.9
Haynesville Shale			353.6	59.0	0%	68%	27.1
Total Core Areas	**291.5**	**74.7**	**994.8**	**532.0**	**69%**	**32%**	**81.1**
Other(1)	1.9	1.0	75.7	15.5	19%	81%	5.0
Total	**293.4**	**75.7**	**1,070.5**	**547.5**	**67%**	**33%**	**86.1**

(1) Comprised of South Louisiana Wilcox and Arklatex Tight Gas assets.

Approximately 165 MMBoe, or 30%, of our total proved reserves are proved developed producing assets, which generated an average production of 86,108 Boe/d in 2013 from approximately 1,405 wells. As of December 31, 2013, we had approximately 293 MMBbls of proved oil reserves, 76 MMBbls of proved NGLs reserves and 1,071 Bcf of proved natural gas reserves in the United States, representing 54%, 13% and 33%, respectively, of our total proved reserves. For the year ended December 31, 2013, 51% of our production and 80% of our revenues (excluding realized and unrealized gains on financial derivatives) were related to oil and NGLs versus 31% and 66% in 2012, respectively, and over that same period and on that same basis, our continuing oil production has grown by approximately 55%. As a result of our development program and our divestitures of natural gas assets in 2013, the oil-weighting of our reserves is 54% as of December 31, 2013 as compared to 42% as of December 31, 2012 without giving effect to the divestitures of certain natural gas assets in 2013. We anticipate that substantially all of our 2014 capital expenditures will be allocated to our core oil programs.

We operate over 87% of our producing wells and have operational control over approximately 95% of our core area drilling inventory as of December 31, 2013. 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 operational structure to accelerate our internal knowledge transfer around the execution of our drilling and completion programs and to continually enhance our field operations and base production performance. In 2013, we drilled 231 wells with a success rate of 99%, adding approximately 147 MMBoe of proved reserves (79% of which were liquids), excluding divested assets. Our reserve replacement cost as of December 31, 2013 was $12.62 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.

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Core 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 and Atascosa counties. 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, with initial 30-day oil equivalent production rates up to 1,100 Boe/d, comprised of 893 Bbl/d of oil, 97 Bbl/d of NGLs and 662 Mcf/d of natural gas. We currently have 91,675 net (104,958 gross) acres in the Eagle Ford, in which we have identified 946 drilling locations.

During 2013, we invested $1,191 million in capital expenditures in our Eagle Ford Shale and operated an average of 5.5 drilling rigs. As of December 31, 2013, we had 271 net producing wells (270 net operated wells) and are currently running six rigs. For the year ended December 31, 2013, our average net daily production was 36,637 Boe/d, representing growth of 82% over the same period in 2012. For the year ended December 31, 2013 our average cost per gross well was $7.4 million ($6.8 million per net well), representing a 12% decline from our average cost per gross well (17% per net well) from 2012.

Wolfcamp Shale. The Wolfcamp Shale is located in the Permian Basin. The Permian Basin is characterized by numerous, stacked oil reservoirs that provide excellent targets for horizontal drilling. In 2009 and 2010, we leased 138,130 net (138,469 gross) acres on the University of Texas Land System in the Wolfcamp Shale, located primarily in Reagan, Crockett, Upton and Irion counties. Our large, contiguous acreage positions are characterized by stacked pay zones, including the Wolfcamp A, B, and C, 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. We are currently in full development of the Wolfcamp B and C. Our initial 30-day oil equivalent production rates are up to 700 Boe/d, comprised of 516 Bbl/d of oil, 88 Bbl/d of NGLs and 577 Mcf/d of natural gas. As of December 31, 2013, we have 138,173 net (138,512 gross) acres in the Wolfcamp, in which we have identified approximately 2,900 drilling locations in the Wolfcamp A, the Wolfcamp B and the Wolfcamp C. In early 2013, we piloted a five-well development program in the Wolfcamp B and Wolfcamp C using alternating laterals. Initial results of the pilot program suggest that the combined development of the two zones may yield greater oil recovery from each interval. We plan to continue with this development approach in 2014. On the first 19 wells developed in 2013 and early 2014 utilizing this approach, our initial 30-day oil equivalent production rates have averaged 545 Boe/d, comprised of 353 Bbl/d of oil, 92 Bbl/d of NGLs and 602 Mcf/d of natural gas.

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 2013, we invested $505 million in capital expenditures in our Wolfcamp Shale and operated an average of 3.0 drilling rigs. As of December 31, 2013, we had 99 net operated producing wells and are currently running three rigs. For the year ended December 31, 2013, our average net daily production was 5,478 Boe/d, representing growth of 173% over 2012. For the year ended December 31, 2013 our average cost per gross well was $5.6 million ($5.6 million per net well), representing a 27% decline from our average cost per gross well (27% per net well) from 2012.

Altamont. The Altamont field is located in the Uinta Basin in northeastern Utah. 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 173,110 net (313,686 gross) acres in Duchesne and Uinta Counties. The Altamont Field Complex has gross thicknesses over 4,300 feet across multiple sandstone and carbonate intervals and we believe the Wasatch and Green River formations are ideal targets for low-risk, infill, vertical drilling and modern fracture stimulation techniques. The commingled production from over 1,500 feet of net stimulated rock results in initial 30-day oil production rates of up to 950 Boe/d, comprised of approximately 799 Bbl/d of oil and 907 MMcf/d of natural gas. Our current activity is mainly focused on the development of our vertical inventory on 160-acre spacing. As of December 31, 2013, we have identified an inventory of 1,126 drilling locations (776 vertical and 350 horizontal). The industry is currently piloting 80-acre vertical downspacing programs in the Wasatch and Green River formations and horizontal development programs in the multiple shale, carbonate and tight 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 2013, we invested $207 million in capital expenditures in the Altamont Field, operated an average of 2.5 drilling rigs, and drilled 27 gross wells. As of December 31, 2013, we had 325 net producing wells (318 net operated wells) and are currently running four rigs, with the addition of a fourth rig in late January 2014. For the year ended December 31, 2013, our average net daily production was 11,855 Boe/d, representing growth of 12% over 2012. For the year ended December 31, 2013 our average cost per gross well was $5.4 million ($4.5 million per net well), representing a 9% decline from our average cost per gross well (23% per net well) from 2012.

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Haynesville Shale. In addition to our core 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 36,865 net (55,817 gross) acres in this area. As of December 31, 2013, we have identified 197 drilling locations.

During 2013, we invested $1 million in capital expenditures in our Haynesville Shale program. For the year ended December 31, 2013, our average net daily production was 163 MMcfe/d. As of December 31, 2013, we had 194 producing wells, which provided cash flow to fund the development of our core oil programs. Although we had a very efficient drilling program in the Haynesville Shale, we suspended the program in early 2012 due to low natural gas prices. At this time, we do not plan to drill any new wells in the Haynesville Shale in 2014. Although we believe our wells generate attractive returns in the current natural gas price environment, we have chosen to allocate capital to our higher-return, oil-weighted areas. Our acreage in the Haynesville Shale is 100% held-by-production, giving us the flexibility to allocate capital in the future to this natural gas-weighted asset.

The following table provides a summary of acreage and inventory data for our core areas, as of December 31, 2013:

Core Acreage and Inventory Summary as of December 31, 2013

	Acres		Drilling Locations(1) (#)	2013 Drilling Locations(2) (#)	Inventory (Years)(3)	Working Interest (%)	Net Revenue Interest (%)
	Gross	**Net**					
Core Areas							
Eagle Ford Shale	104,958	91,675	946	136	7.0	90%	68%
Wolfcamp Shale	138,512	138,173	2,900	68	42.6	96%	72%
Wolfcamp A			1,001			96%	72%
Wolfcamp B			912			96%	72%
Wolfcamp C			987			96%	72%
Altamont	313,686	173,110	1,126	27	41.7	72%	60%
Vertical			776			73%	61%
Horizontal			350			71%	59%
Haynesville Shale	55,817	36,865	197		NA	79%	63%
Holly			104			81%	66%
Non-Holly			93			76%	58%
Total Core Areas	**612,973**	**439,823**	**5,169**	**231**	**22.4**	**88%**	**68%**

(1) Our inventory as of December 31, 2013 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) vertical infill locations and (ii) horizontal drilling locations in the Wasatch and Green River formations.

(2) Represents gross operated wells completed in 2013.

(3) Calculated as Drilling Locations divided by 2013 Drilling Locations.

We use 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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Other Oil and Natural Gas Properties and Assets

We have other domestic producing assets that contribute to our operations. During 2013, we invested an aggregate of $12 million in capital expenditures in the following areas:

South Louisiana Wilcox. In our South Louisiana Wilcox area we control 47,447 total net (52,161 gross) acres located primarily in Beauregard Parish, Louisiana. We focus on development of the conventional vertical Wilcox area which produces oil, natural gas and NGLs from a series of completed sands. We are also evaluating horizontal drilling in certain sand intervals. We have over 1,000 square miles of 3-D seismic data across this play. The oil and NGLs from South Louisiana Wilcox have access to Louisiana Light Sweet Crude and Gulf Coast NGLs pricing, respectively. In addition, it does not compete for horizontal drilling and completion services due to vertical drilling and completion design. For the year ended December 31, 2013 we had average daily production of 1.5 MBoe/d and as of that date we had 21 net producing wells.

Arklatex Tight Gas. Our Arklatex Tight Gas area includes wells producing from reservoirs other than the Haynesville Shale in our acreage located in Northern Louisiana. These properties are generally in the same areas as our Haynesville Shale. Our wells in this area produce from reservoirs such as the Travis Peak, Hosston and Cotton Valley, and have relatively stable production with shallow declines rates. In the current gas price environment, we are not currently drilling in this area. We have a significant low-risk inventory in this area that we believe would generate economic returns at higher gas prices. For the year ended December 31, 2013, we had average daily production of 3.4 MBoe/d and as of that date we had 272 net producing wells.

Discontinued Operations

We also have exploration and development projects in offshore Brazil that are under contract to be sold and treated as discontinued operations in our financial statements. Our Brazilian operations are in the Camamu, Espirito Santo and Potiguar basins covering approximately 33,000 net acres. During 2013, we invested $1 million on capital projects in Brazil, and production averaged 5.0 MBoe/d. As of December 31, 2013, we have 11.6 MMBoe of net proved reserves in Brazil. The sale of Brazil is expected to close in 2014, subject to Brazilian regulatory approval and certain other customary closing conditions.

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Oil and Natural Gas Properties

Oil and Condensate, Natural Gas and NGLs Reserves and Production

Proved Reserves

The table below presents information about our estimated net proved reserves as of December 31, 2013, 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, 2013.

			Net Proved Reserves		
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Percent (%)
Reserves by Classification					
Proved Developed					
Core Areas					
Eagle Ford Shale	44.1	12.1	83.8	70.0	13%
Wolfcamp Shale	11.0	5.3	30.8	21.5	4%
Altamont	27.9		60.9	38.1	7%
Haynesville Shale			241.0	40.2	7%
Total Core Areas	83.0	17.4	416.5	169.8	31%
Other	1.0	0.3	67.5	12.6	2%
Total Proved Developed(1)	84.0	17.7	484.0	182.4	33%
Proved Undeveloped					
Core Areas					
Eagle Ford Shale	129.5	42.8	292.8	221.2	40%
Wolfcamp Shale	34.9	14.5	84.2	63.4	12%
Altamont	44.1		88.7	58.8	11%
Haynesville Shale			112.6	18.8	3%
Total Core Areas	208.5	57.3	578.3	362.2	66%
Other	0.9	0.7	8.2	2.9	1%
Total Proved Undeveloped	209.4	58.0	586.5	365.1	67%
Total Proved Reserves	293.4	75.7	1,070.5	547.5	100%

(1) Includes 165 MMBoe of proved developed producing reserves representing 30% of total net proved reserves and 17 MMBoe of proved developed non-producing reserves representing 3% of total net proved reserves at December 31, 2013.

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, 2013.

	Net Proved Reserves (MMBoe)
As Reported	547.5
10 percent increase in commodity prices(1)	549.7
10 percent decrease in commodity prices(1)	528.1

(1) Based on the first day 12-month average U.S prices of $96.94 per barrel of oil and $3.67 per MMBtu of natural gas used to determine net proved reserves at December 31, 2013.

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,

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correlation of known penetrations, decline curve analysis of producing locations with significant production history, well testing, static bottom hole testing, flowing bottom hole pressure analysis and pressure and rate transient analysis.

Our primary internal technical person in charge of overseeing our reserves estimates has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is the executive vice president and chief operating officer of the company. In this capacity, he is responsible for the company s operating divisions as well as the Marketing and Business Development groups. In addition, he 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, 2013. In connection with its audit, Ryder Scott reviewed 94% (by volume) of our total net proved reserves (or 96% not including proved reserves associated with our Brazil assets classified as discontinued operations) on a barrel of oil equivalent basis, representing 96% of the total discounted future net cash flows of these net proved reserves. For the audited properties, 98% of our total net PUD reserves were evaluated. As of December 31, 2013, we did not have PUD reserves associated with our Brazil assets. Ryder Scott concluded the overall procedures and methodologies that we utilized in preparing our estimates of net proved reserves as of December 31, 2013 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 (SPE) 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 10 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, 2013, we have 981 net PUD locations, of which 968 are in our core areas. At this time we do not have a developed to undeveloped relationship that is beyond one adjacent offset to a productive well.

We assess our PUD reserves on a quarterly basis. At December 31, 2013, we had 365 MMBoe of PUD reserves, representing an increase of 50 MMBoe of PUD reserves compared to December 31, 2012, excluding sales related to our divestitures of 26 MMBoe of PUD reserves. During 2013, we added 109 MMBoe of PUD reserves primarily from our drilling activities in the Eagle Ford Shale and the Wolfcamp Shale. We had 39

MMBoe of PUD reserves transferred to proved developed reserves and positive revisions of 6 MMBoe primarily due to better than originally forecasted performance of offsetting proved developed producing properties. As of December 31, 2013, we have no PUD reserves associated with our Brazil assets classified as discontinued operations.

We spent approximately $679 million, $587 million and $601 million during 2013, 2012 and 2011, respectively, to convert approximately 12% or 39 MMBoe, 10% or 32 MMBoe and 17% or 35 MMboe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2013 internal reserve report, the amounts estimated to be spent in 2014, 2015 and 2016 to develop our PUD reserves are $1,187 million, $1,611 million and $1,556 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 core 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.

Of the 365 MMBoe of PUD reserves at December 31, 2013, none are scheduled to remain undeveloped beyond five years.

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The following table summarizes our changes in PUDs for the years ended December 31, 2012 and December 31, 2013, respectively (in MMBoe):

Balance, December 31, 2011	320
Extensions and discoveries	131
Revisions of previous estimates(1)	(103)
Transfers to proved developed	(32)
Divestitures	(1)
Balance, December 31, 2012	**315**
Extensions and discoveries	109
Revisions of previous estimates(2)	6
Transfers to proved developed	(39)
Divestitures	(26)
Balance, December 31, 2013	**365**

(1) Revisions to previous estimates during 2012 are primarily due to lower natural gas prices.

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

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Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2013, (ii) our interest in oil and natural gas wells at December 31, 2013 and (iii) our exploratory and development wells drilled during the years 2011 through 2013. 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						
Core Areas						
Eagle Ford Shale	19,406	18,211	85,552	73,464	104,958	91,675
Wolfcamp Shale	14,271	14,220	124,241	123,953	138,512	138,173
Altamont	139,574	118,779	174,112	54,331	313,686	173,110
Haynesville Shale	38,571	27,362	17,246	9,503	55,817	36,865
Total Core Areas	211,822	178,572	401,151	261,251	612,973	439,823
Other(3)	144,858	33,660	381,836	253,819	526,694	287,479
Total Acreage	356,680	212,232	782,987	515,070	1,139,667	727,302

(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.

(3) Includes South Louisiana Wilcox and Arklatex Tight Gas areas.

Our net developed acreage is concentrated primarily in Utah (56%), Louisiana (22%) and Texas (19%). Our net undeveloped acreage is concentrated primarily in Texas (40%), Wyoming (12%), Utah (11%), Michigan (10%), and Colorado (9%). Approximately 6%, 15% and 10% of our net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2014, 2015 and 2016, 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, 2013(1)**	
	Gross(2)	**Net(4)**	**Gross(2)(3)**	**Net(4)**	**Gross(2)**	**Net(4)(5)**	**Gross(2)**	**Net(4)**
Productive Wells								
Core Areas								
Eagle Ford Shale	284	269	3	3	287	272	24	24
Wolfcamp Shale	105	102			105	102	19	19
Altamont	432	324	3	1	435	325	7	5
Haynesville Shale			194	106	194	106		
Total Core Areas	821	695	200	110	1,021	805	50	48
Other(6)	5	4	379	288	384	292		
Total Productive Wells	826	699	579	398	1,405	1,097	50	48

(1) Comprised of wells that were spud as of December 31, 2013 and have not been completed.

(2) Gross interest reflects the total wells we participated in, regardless of our ownership interest.

(3) Includes three wells with multiple completions.

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

(5) At December 31, 2013, we operated 1,077 of the 1,097 net productive wells.

(6) Includes South Louisiana Wilcox and Arklatex Tight Gas areas.

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	Net Exploratory(1)			Net Development(1)		
	2013	2012	2011	2013	2012	2011
Wells Drilled						
Core Areas						
Productive	8	13	73	216	116	57
Dry		1		2	2	
Total Core Areas	8	14	73	218	118	57
Other						
Productive		7	9		5	2
Dry					1	
Total Other		7	9		6	2
Divested Assets(2)						
Productive			5		11	36
Dry						
Total Divested Assets			5		11	36
Total						
Productive	8	20	87	216	132	95
Dry		1		2	3	
Total Wells Drilled	8	21	87	218	135	95

(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 and 2011 include those for 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 core area and other, 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:

	2013	2012	2011
Volumes:			
Consolidated Net Production Volumes			
Core Areas			
Oil and Condensate (MBbls)	13,230	8,277	4,220
Natural Gas (MMcf)	83,606	122,254	105,429
NGLs (MBbls)	2,424	1,056	216
Total Core Areas (MMBoe)	29,588	29,709	22,008
Other			
Oil and Condensate (MBbls)	285	427	234
Natural Gas (MMcf)	8,634	12,603	14,440
NGLs (MBbls)	117	245	22
Total Other (MMBoe)	1,841	2,772	2,662
Core Areas and Other			
Oil and Condensate (MBbls)	13,515	8,704	4,454
Natural Gas (MMcf)	92,240	134,857	119,869
NGLs (MBbls)	2,541	1,301	238
Total Core Areas and Other (MMBoe)	31,429	32,481	24,670
Divested Assets(1)			
Oil and Condensate (MBbls)		297	1,226
Natural Gas (MMcf)		39,419	110,800
NGLs (MBbls)		312	830
Total Divested Assets(MMBoe)		7,179	20,523
Consolidated			
Oil and Condensate (MBbls)	13,515	9,001	5,680
Natural Gas (MMcf)	92,239	174,276	230,669
NGLs (MBbls)	2,541	1,613	1,068
Total Consolidated (MMBoe)	31,429	39,660	45,193
MBoe/d	*86.1*	*108.4*	*123.8*
Unconsolidated Affiliate(2)			
Oil and Condensate (MBbls)	197	282	306
Natural Gas (MMcf)	10,050	15,552	16,881
NGLs (MBbls)	327	478	556
Total Unconsolidated Affiliate (MMBoe)	2,199	3,352	3,675
MBoe/d	*6.0*	*9.2*	*10.1*
Total Combined Volumes			
Oil and Condensate (MBbls)	13,712	9,283	5,986
Natural Gas (MMcf)	102,289	189,828	247,550
NGLs (MBbls)	2,868	2,091	1,624
Total Equivalent Volumes (MMBoe)	33,628	43,012	48,868
MBoe/d	*92.1*	*117.6*	*133.9*

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(1) Predecessor periods prior to May 24, 2012 include volumes from 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 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) Represents our approximate 49% equity interest in the volumes of Four Star Oil & Gas Company (Four Star), which we sold in September 2013.

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	2013	2012	2011
Core Area Net Production Volumes			
Eagle Ford Shale			
Oil and Condensate (MBbls)	8,763	5,023	1,702
Natural Gas (MMcf)	14,857	8,425	3,094
NGLs (MBbls)	2,133	936	207
Total Eagle Ford Shale (MMBoe)	13,372	7,364	2,425
Wolfcamp Shale			
Oil and Condensate (MBbls)	1,306	489	132
Natural Gas (MMcf)	2,483	763	212
NGLs (MBbls)	280	116	
Total Wolfcamp Shale (MMBoe)	2,000	734	168
Altamont			
Oil and Condensate (MBbls)	3,161	2,765	2,385
Natural Gas (MMcf)	6,931	6,632	5,677
NGLs (MBbls)	11	4	7
Total Altamont (MMBoe)	4,327	3,876	3,338
Haynesville Shale			
Oil and Condensate (MBbls)			1
Natural Gas (MMcf)	59,335	106,434	96,446
NGLs (MBbls)			2
Total Haynesville Shale (MMBoe)	9,889	17,736	16,077

	2013	2012	2011
Consolidated Prices and Costs per Unit:			
Oil and Condensate Average Realized Sales Price ($/Bbl)			
Physical Sales	$ 94.97	$ 92.58	$ 90.22
Including Financial Derivatives(1)	$ 97.72	$ 97.19	$ 88.98
Natural Gas Average Realized Sales Price ($/Mcf)			
Physical Sales	$ 3.31	$ 2.54	$ 3.91
Including Financial Derivatives(1)	$ 3.02	$ 4.49	$ 5.37
NGLs Average Realized Sales Price ($/Bbl)			
Physical Sales	$ 30.81	$ 37.63	$ 53.50

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(1) Amounts reflect settlements on financial derivatives, including cash premiums. For the years ended December 31, 2013 and 2012 we received $9 million and paid $3 million of cash premiums, respectively. There were no cash premiums for the year ended December 31, 2011.

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	2013	2012	2011
Average Transportation Costs			
Core Areas			
Oil and Condensate ($/Bbl)	$ 2.01	$ 2.09	$ 0.05
Natural Gas ($/Mcf)	$ 0.52	$ 0.40	$ 0.34
NGLs ($/Bbl)	$ 6.08	$ 2.93	$ 1.12
Other			
Oil and Condensate ($/Bbl)	$ 0.01	$ 0.02	$ 0.02
Natural Gas ($/Mcf)	$ 0.83	$ 0.46	$ 0.39
NGLs ($/Bbl)	$ 7.95	$ 9.32	$ 11.46
Core Areas and Other(1)			
Oil and Condensate ($/Bbl)	$ 1.96	$ 1.99	$ 0.05
Natural Gas ($/Mcf)	$ 0.55	$ 0.40	$ 0.35
NGLs ($/Bbl)	$ 6.17	$ 4.12	$ 2.06
Divested Assets(2)			
Oil and Condensate ($/Bbl)	$	$ 0.17	$ 0.13
Natural Gas ($/Mcf)	$	$ 0.43	$ 0.35
NGLs ($/Bbl)	$	$ 6.82	$ 4.33
Consolidated			
Oil and Condensate ($/Bbl)	$ 1.96	$ 1.93	$ 0.06
Natural Gas ($/Mcf)	$ 0.55	$ 0.41	$ .35
NGLs ($/Bbl)	$ 6.17	$ 4.65	$ 3.83
Average Lease Operating Expenses ($/Boe)			
Core Areas	$ 5.04	$ 3.26	$ 2.53
Other	$ 7.49	$ 5.33	$ 5.17
Core Areas and Other(1)	$ 5.19	$ 3.43	$ 3.04
Divested Assets(2)	$	$ 5.44	$ 5.19
Total Consolidated	$ 5.19	$ 3.80	$ 3.89
Average Production Taxes ($/Boe)			
Core Areas	$ 2.84	$ 1.93	$ 1.25
Other	$ 3.99	$ 3.30	$ 2.50
Core Areas and Other(1)	$ 2.90	$ 2.04	$ 1.38
Divested Assets(2)	$	$ 1.18	$ 1.71
Total Consolidated	$ 2.90	$ 1.89	$ 1.53

(1) Average costs per unit are calculated using only costs associated with core areas and other oil and natural gas properties divided by the production of those areas.

(2) Divested assets in 2012 and 2011 represents activity prior to May 24, 2012 and include our CBM, South Texas and Arklatex assets, each sold in 2013 and our Gulf of Mexico assets sold in 2012.

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Acquisition, Development and Exploration Expenditures

See Part II, Item 8, Financial Statements and Supplementary Data under the heading Supplemental Oil and Natural Gas Operations in the 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 to achieve 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, 2013, three purchasers accounted for approximately 80% of our oil revenues: Chevron Corporation, Flint Hills Resources, LP, an affiliate of Koch Industries and 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 core 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, which is comprised of a crude oil gathering pipeline system and a separate natural gas gathering pipeline system. The Camino Real gas gathering system receives high-pressure unprocessed wellhead gas into an 83-mile pipeline with capacity of 150-170 MMcf/d. The gas is redelivered to interconnects with Energy Transfer, Enterprise, Regency and Eagle Ford Gathering. We currently have 125 MMcf/d of firm transportation capacity on the Camino Real gas gathering system, of which we used an average of 76% during the month of December 2013, and have additional capacity available as needed. Our gas gathering capacity utilization will increase as additional wells are connected. We have firm gas gathering, processing and transportation agreements on three of the interconnected pipelines downstream of the Camino Real gas gathering system that range between 85 and 100 MMBtu/d, with rights to increase firm capacity if necessary. We market our physical gas to various purchasers at spot market prices.

The Camino Real oil gathering system is a 68-mile long pipeline with over 110,000 Bbls/d of capacity and a gravity bank which allows for oil blending to support attractive API levels. We have 80,000 Bbls/d of firm capacity on this system, of which we used an average of 41% during December 2013. 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 Arrowhead #2 pipelines or loaded into trucks. Oil can also be delivered into trucks at the various central tank batteries throughout the field, providing additional deliverability and flexibility. We expect our utilization rate of this system to increase as additional wells are connected. We currently market our oil 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 are receiving a price premium for our Eagle Ford Shale oil relative to NYMEX/WTI, due primarily to Louisiana Light Sweet pricing and exposure to waterborne crude markets. With adequate takeaway capacity in the region and close proximity to the Gulf Coast refining complex, we do not anticipate any issues with marketing additional crude volumes from the Eagle Ford Shale.

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 gas plant. 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 Plains pipeline at Owens Station in Reagan County, Texas. We sell our pipeline delivered crude to multiple purchasers under both short and long-term contracts at WTI-based pricing. We also maintain the capability to truck crude oil to those same purchasers under similarly-priced contracts to provide additional flow assurance. With new Permian Basin takeaway pipelines coming online this year, we anticipate no constraints 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. 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 growth forecasts. In addition, we entered a crude-by-rail solution four years ago 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

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produced natural gas is gathered and processed at an Altamont plant under a long-term sales agreement that provides for residue gas return for operational use.

In our Haynesville Shale operating area, our 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 300 MMcf/d of firm capacity on these pipelines, of which we used an average of 51% during December 2013. Currently, our Haynesville Shale gas is produced at close to pipeline specifications and requires only CO2 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.

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 2,100 square miles of 3-D seismic data. We have 1,027 square miles of 3-D seismic data in our four core areas which provides approximately 36% 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 and Brazil. 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 domestic operations under federal oil and natural gas leases are regulated by the statutes and regulations of the U.S. Department of the Interior 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 Department of Interior, which has promulgated valuation guidelines for the payment of royalties by producers. Our exploration and production operations in Brazil are subject to environmental regulations administered by that government, which include political subdivisions in that country. These domestic and international 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 core areas. Our domestic proved undeveloped oil and natural gas reserves are subject to hydraulic fracturing. For the year ended December 31, 2013, we incurred costs of approximately $521 million associated with hydraulic fracturing.

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

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

- 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 USDW s.

- 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

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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.

Environmental

A description of our environmental remediation activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 9.

Employees

As of February 25, 2014, we had 770 full-time employees in the United States. We also had 30 employees in Brazil who are subject to collective bargaining arrangements.

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 the members of our board of directors, 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.

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:

- 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;

- 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;

- 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;

- adoption of various energy efficiency and conservation measures;

- increased prices of oil, natural gas or NGLs that could negatively impact the demand for these products;

- perceptions of customers on the availability and price volatility of our products, particularly customers perceptions on the volatility of natural gas and oil prices over the longer-term;

- 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;

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- 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 oversupply of NGLs that may be caused by the wider spread between oil and natural gas prices;
- competition from imported and potentially exported liquefied natural gas (LNG), Canadian supplies and alternate fuels;
- increased costs to explore for, develop and produce oil, natural gas or NGLs, including increases in oil field service costs; and
- the impact of weather on demand for oil, natural gas and/or NGLs.

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. There is a risk that commodity prices could remain depressed for sustained periods, especially natural gas prices. 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;
- 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;
- technological advances affecting energy consumption and energy supply;
- domestic and foreign 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.

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.

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 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.

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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 rules adopted 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 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. We have established a capital budget for 2014 of approximately $2.0 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 asset sale transactions such as the pending and recently completed divestitures 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, however, 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

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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.

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 member s 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

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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. During these periods, the cost of rigs, equipment, supplies and personnel are substantially greater and their availability may be limited. These services may not be available on commercially reasonable terms or at all. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. 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 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. Our offshore operations in Brazil, which are in the process of being divested, may encounter additional marine perils, including adverse weather conditions, damage from collisions with

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vessels, and governmental regulations (including interruption or termination of drilling rights by governmental authorities based on environmental, safety and other considerations).

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, 2013, three 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.

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;

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- plugging and abandoning of wells, even if we no longer own and/or operate such wells;
- air quality, 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.

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 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

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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, and Dane E. Whitehead, our Executive Vice President and Chief Financial 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.

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.

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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 several 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 scheduled to be drilled 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.

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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, some local water districts have begun restricting the use of water subject to their 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;

- 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;

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- 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 fund our anticipated capital program there is a risk that some of our existing proved reserves and some of our unproved inventory could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in 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 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.

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. 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.

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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. Our exploration and production operations in Brazil (which we expect to sell in 2014) are subject to various types of regulations similar to those described above, which are imposed by the Brazilian government, and which may affect our operations and costs within that country. 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 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 on October 15, 2013, the U.S. Supreme Court announced it will review aspects of the rule in 2014. 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 may include certain of our facilities, beginning in 2012 for emissions occurring in 2011. 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 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

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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.

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 in the Gulf of Mexico. Although we have sold our Gulf of Mexico assets, it is possible that similar, more stringent, regulations might be enacted or delays in receiving permits may occur in other areas, such as in offshore regions of other countries (such as Brazil) and in other 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.

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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 by 2014 governing wastewater discharges from hydraulic fracturing and certain other natural gas operations. In addition, the DOI published a revised proposed rule on May 24, 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water. The revised proposed rule was subject to an extended 90-day public comment period, which ended on August 23, 2013 and a final rule is expected in 2014.

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 is anticipated by 2014 for peer review and public comment. 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, 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 must be reduced through reduced emission completions or combustion devices. The rules also establish new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In response to numerous requests for reconsideration of these rules from both industry and the environmental community and court challenges to the final rules, EPA announced its intention to issue revised rules in 2013. For example, 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.

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 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.

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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 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.

Our Brazilian operations involve special risks.

In July 2013, we entered into a Quota Purchase Agreement relating to the sale of our Brazil operations, which is expected to close in 2014. Pending the closing of that divestiture, we will continue activities in Brazil, which are subject to the risks inherent in foreign operations and other additional risks not associated with assets located in the United States, which include:

- protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations;
- loss of revenue, property and equipment as a result of hazards such as wars, insurrection, piracy or acts of terrorism;
- changes in laws, regulations and policies of foreign governments, including changes to tax laws and regulations and changes in the governing parties, nationalization, expropriation and unilateral renegotiation of contracts by government entities;
- difficulties in enforcing rights against government agencies, including being subject to the jurisdiction of local courts in certain instances;

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- the effects of currency fluctuations and exchange controls, such as devaluation of foreign currencies, relative inflation risks, and the imposition of foreign exchange restrictions that may negatively impact convertibility and repatriation of our foreign earnings into U.S. dollars;

- protracted delays in payments and collections of accounts receivables from state-owned energy companies;

- transparency and corruption issues, including compliance issues with the U.S. Foreign Corrupt Practices Act, the United Kingdom bribery laws and other anti-corruption compliance issues; and

- laws and policies of the United States that adversely affect foreign trade and taxation.

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 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 and have agreed to sell various assets and either retained certain liabilities or indemnified certain purchasers against future liabilities relating to businesses and assets sold or to be 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. 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:

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

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

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

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

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

Such actions by the lenders could cause cross defaults under our other indebtedness. If we were unable to repay those amounts, the lenders or holders under the RBL Facility and our other secured indebtedness could proceed against the collateral granted to them to secure that indebtedness. We pledged a significant portion of our assets as collateral under the RBL Facility, 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 9, and is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Disclosure Pursuant to Section 219 of the Iran Threat Reduction and Syria Human Rights Act

Apollo Global Management, LLC (Apollo) has provided notice to us that, as of October 24, 2013, certain investment funds managed by affiliates of Apollo beneficially owned approximately 22% of the limited liability company interests of CEVA Holdings, LLC (CEVA). Under the limited liability company agreement governing CEVA, certain investment funds managed by affiliates of Apollo hold a majority of the voting power of CEVA and have the right to elect a majority of the board of CEVA. CEVA may be deemed to be under common control with us, but this statement is not meant to be an admission that common control exists. As a result, it appears that we are required to provide disclosures as set forth below pursuant to Section 219 of the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) and Section 13(r) of the Securities Exchange Act of 1934, as amended (the Exchange Act).

Apollo has informed us that CEVA has provided it with the information below relevant to Section 13(r) of the Exchange Act. The disclosure below does not relate to any activities conducted by us and does not involve us or our management. The disclosure relates solely to activities conducted by CEVA and its consolidated subsidiaries. We have not independently verified or participated in the preparation of the disclosure below.

Through an internal review of its global operations, CEVA has identified the following transactions in an Initial Notice of Voluntary Self-Disclosure that CEVA filed with the U.S. Treasury Department Office of Foreign Assets Control (OFAC) on October 28, 2013. CEVA s review is ongoing. CEVA will file a further report with OFAC after completing its review.

The internal review indicates that, in February 2013, CEVA Freight Holdings (Malaysia) SDN BHD (CEVA Malaysia) provided customs brokerage for export and local haulage services for a shipment of polyethylene resin to Iran shipped on a vessel owned and/or operated by HDS Lines, also an SDN. The revenues and net profits for these services were approximately $779.54 USD and $311.13 USD, respectively. In September 2013, CEVA Malaysia provided customs brokerage services for the import into Malaysia of fruit juice from Alifard Co. in Iran via HDS Lines. The revenues and net profits for these services were approximately $227.41 USD and $89.29 USD, respectively.

These transactions violate the terms of internal CEVA compliance policies, which prohibit transactions involving Iran. Upon discovering these transactions, CEVA promptly launched an internal investigation, and is taking action to block and prevent such transactions in the future. CEVA intends to cooperate with OFAC in its review of this matter.

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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 20, 2014, we had 23 stockholders of record which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or bank.

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, 2013 and December 31, 2012 and the statements of income data and statements of cash flow data for the year ended December 31, 2013, for the period from February 14 to December 31, 2012, the period from January 1, 2012 through May 24, 2012 and the year ended December 31, 2011, 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, 2011, 2010 and 2009, and the statements of income data and statements of cash flow data for the years ended December 31, 2010 and 2009 from the consolidated historical predecessor financial statements of EP Energy Corporation, which are 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, 2013	February 14 to December 31, 2012	January 1, to May 24, 2012	For Years ended December 31, 2011	2010	2009
			(in millions)			
Results of Operations						
Operating revenues	$ 1,640	$ 727	$ 932	$ 1,756	$ 1,704	$ 1,803
Operating income (loss)	380	(66)	338	648	738	(1,231)
Interest expense	(354)	(219)	(14)	(14)	(23)	(27)
(Loss) income from continuing operations	(58)	(300)	187	385	451	(823)
Cash Flow						
Net cash provided by (used in):						
Operating activities	$ 960	$ 449	$ 580	$ 1,426	$ 1,067	$ 1,573
Investing activities	(475)	(7,893)	(628)	(1,237)	(1,130)	(1,156)
Financing activities	(503)	7,513	110	(238)	(46)	(336)

	As of December 31,		As of December 31,		
	2013	2012	2011	2010	2009
			(in millions)		
Financial Position					
Total assets	$ 8,366	$ 8,306	$ 5,103	$ 4,942	$ 4,457
Long-term debt	4,421	4,695	851	301	835
Member s/Stockholder s equity	2,937	2,748	3,100	3,067	2,529

Factors Affecting Trends. In May 2012, the Sponsors acquired our subsidiary for approximately $7.2 billion with approximately $3.3 billion in equity contributions and the issuance of $4.25 billion of debt. For the period 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

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December 31, 2011, 2010 and 2009 we recorded realized and unrealized gains on financial derivatives included in operating revenues of $365 million, $284 million, $390 million and $687 million, and non-cash ceiling test and other impairment charges of $62 million, $6 million, $25 million and $2.1 billion, 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 CBM, South Texas and the majority of our 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, trends and results in future periods may be different than those that existed prior to the Acquisition. 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 its 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 our four core areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), Altamont field in the Uinta Basin (Northeastern Utah) and the Haynesville Shale (North Louisiana). We also have other domestic activities in Texas and Louisiana. Below are summary descriptions of each of our core programs further described in Item I, Business:

- ***Eagle Ford Shale.*** The Eagle Ford Shale provides the highest economic returns in our portfolio.

- ***Wolfcamp Shale.*** In our Wolfcamp Shale program, we are focused on optimizing our drilling, completion and artificial lift systems.

- ***Altamont.*** In Altamont, we are gaining operational efficiencies as we develop this oil-based field. Most of our acreage in this area is held-by-production.

- ***Haynesville Shale.*** The Haynesville Shale generates positive cash flow and remains a core natural gas option for us when natural gas prices return to more economic levels in the future. Our acreage in the Haynesville shale is predominantly held-by-production.

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 our core 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 2013, we sold certain of our natural gas properties, including CBM properties located in the Raton, Black Warrior and Arkoma basins; the majority of our Arklatex natural gas properties; our natural gas properties in South Texas and our interests in Four Star Oil & Gas Company (Four Star). The total consideration from these transactions was approximately $1.5 billion. In July 2013, certain of our subsidiaries entered into a Quota Purchase Agreement relating to the sale of all of our Brazil operations. This transaction represents the sale of all of our remaining international assets and is expected to close in 2014, subject to Brazilian regulatory approval and certain other customary closing conditions.

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:

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- 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 our ability to execute our strategy, 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, or domestic or international 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. During 2013, approximately 94% of our liquids production and 91% of our natural gas production were hedged and settled at average floor prices of $100.01 per barrel and $3.49 per MMBtu, respectively. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of December 31, 2013.

	2014		2015		2016	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil						
Fixed Price Swaps						
WTI	12,757	$ 97.06	19,928	$ 90.12	5,216	$ 85.25
Brent	3,339	$ 102.54		$		$
Ceilings	1,126	$ 100.00	1,095	$ 100.00		$
Three Way Collars						
Ceiling - WTI	2,920	$ 103.76		$		$
Floors - WTI(2)	2,920	$ 95.00		$		$
Ceiling - Brent		$	1,095	$ 110.02		$
Floors - Brent(3)		$	1,095	$ 100.00		$
Basis Swaps	5,840	$ Various	3,650	$ Various	1,830	$ Various
Natural Gas						

Fixed Price Swaps	76	$	4.02	51	$	4.26	7	$	4.20

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

(2) If market prices settle at or below $75.00 in 2014, we will receive a locked-in cash settlement of the market price plus $20.00 per Bbl.

(3) 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.

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The following table reflects the volumes and the prices associated with derivative contracts entered into between January 1, 2014 and February 24, 2014, which are not reflected in the table above.

	2014			2015			2016		
	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)
Oil									
Fixed Price Swaps									
Brent	160	$	108.44	2,555	$	100.01	4,026	$	95.01
LLS(2)		$			$		2,562	$	93.96
Basis Swaps	1,557	$	Various		$		183	$	Various
Natural Gas									
Fixed Price Swaps		$		4	$	4.20		$	
NGLs									
Propane Fixed Price Swaps	28	$	1.14		$			$	
Propane Collars									
Ceilings	14	$	1.30		$			$	
Floors	14	$	1.00		$			$	

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

(2) In January 2014, we unwound 2,555 MBbls of 2015 WTI fixed price swaps in exchange for 2,562 MBbls of 2016 LLS fixed price swaps. No cash or other consideration was included as part of this exchange.

Summary of Liquidity and Capital Resources. As of December 31, 2013, we had available liquidity, including existing cash, of approximately $2.25 billion. We believe we have sufficient liquidity for 2014 from our cash flows from operations, combined with the availability under our RBL Facility and available cash, to fund our current obligations, projected working capital requirements and capital spending plan. Additionally, the earliest maturity date of our debt obligations is in 2017. See Liquidity and Capital Resources for more information.

Outlook for 2014. For 2014, we expect the following:

- Capital expenditures of approximately $2 billion, or a 4% increase from 2013, allocated entirely to our core oil programs: $1 billion for Eagle Ford, $680 million for Wolfcamp, and $240 million for Altamont.

- 20% increase in well completions from 2013 to between 265 and 290.

- Average daily production volumes for the year of approximately 94.5 MBoe/d to 102.5 MBoe/d, including average daily oil production volumes of approximately 50 MBbls/d to 54 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately $12.25 to $14.35 per Boe, and transportation costs of $3.00 to $3.50 per Boe.

- Per unit depreciation, depletion and amortization rate for the year of approximately $24.00 to $26.00 per Boe.

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Production Volumes and Drilling Summary

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

	2013	2012	2011
United States (MBoe/d)			
Eagle Ford Shale	37	20	7
Wolfcamp Shale	5	2	1
Altamont	12	11	9
Haynesville Shale	27	48	44
Other	5	7	7
Core areas and other	86	88	68
Divested assets(1)		20	56
Total Consolidated	86	108	124
Unconsolidated affiliate (MBoe/d)(2)	6	9	10
Total Combined (MBoe/d)	92	117	134
Oil and condensate (MBbls/d)			
Core areas and other volumes	37	24	12
Divested assets(1)		1	3
Unconsolidated affiliate volumes(2)	1	1	1
Total Combined	38	26	16
Natural Gas (MMcf/d)			
Core areas and other volumes	253	368	328
Divested assets(1)		108	304
Unconsolidated affiliate volumes(2)	28	42	46
Total Combined	281	518	678
NGLs (MBbls/d)			
Core areas and other volumes	7	3	1
Divested assets(1)		1	2
Unconsolidated affiliate volumes(2)	1	1	1
Total Combined (MBbls/d)	8	5	4

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(1) Predecessor periods prior to May 24, 2012 include volumes from our CBM, South Texas, and the majority of our Arklatex assets, all of which were sold in 2013, and our Gulf of Mexico assets, which were sold in 2012. For periods after May 24, 2012, our 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) In September 2013, we sold our equity investment in Four Star.

- *Eagle Ford Shale* Our Eagle Ford Shale equivalent volumes and oil production increased 17 MBoe/d (85%) and 10 MBbls/d (75%), respectively, for the year ended December 31, 2013 compared to 2012 due to the success of our drilling program in the area. In the fourth quarter of 2013 combined Eagle Ford oil and NGLs production increased to approximately 34 MBbls/d compared with approximately 33 MBbls/d during the third quarter of 2013. During 2013, we drilled 136 additional operated wells in the Eagle Ford, and we had a total of 270 net operated wells as of December 31, 2013. With a majority of our acreage located in the core of the oil window, primarily in LaSalle and Atascosa counties, we continue to grow our oil and NGL production in the area.

- *Wolfcamp Shale* Our Wolfcamp Shale equivalent volumes increased 3 MBoe/d (150%) for the year ended December 31, 2013 compared to 2012 as we continue to progress the development of the program. During 2013, we drilled 68 additional operated wells, for a total of 99 net operated wells as of December 31, 2013.

- *Altamont* Our Altamont equivalent volumes increased 1 MBoe/d (9%) for the year ended December 31, 2013 compared to 2012. Altamont produced an average of 9 MBbls/d of oil during 2013, and we drilled an additional 27 operated oil wells for a total of 318 net operated wells at December 31, 2013.

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- *Haynesville Shale* Our Haynesville Shale equivalent volumes decreased 126 MMcf/d (44%) for the year ended December 31, 2013 compared to 2012, due to natural declines as we suspended our drilling program at the end of the first quarter of 2012 as a result of low natural gas prices. As of December 31, 2013, we had 99 net operated wells in the Haynesville Shale, and our total production for 2013 was approximately 163 MMcf/d.

- *Divested assets* Our divested assets were reclassified as discontinued operations in periods after May 24, 2012 and thus volumes related to these assets are not reflected in the successor periods of the table above. Equivalent volumes of divested assets in predecessor periods prior to May 24, 2012 relate to volumes for our divested CBM, south Texas, Arklatex and Gulf of Mexico assets, which are not reflected as discontinued operations.

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Reserve Replacement Ratio/Reserve Replacement Costs

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

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

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

(2) Total oil and natural gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations. Amounts are derived directly from the table presented in Financial Statements and Supplementary Data Supplemental Oil and Natural Gas Operations 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 and Condensate, Natural Gas and NGLs Reserves and Production Proved Undeveloped Reserves (PUDs) for the estimated amounts in our December 31, 2013 internal reserve report to be spent in 2014, 2015 and 2016 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, 2013, proved developed reserves represented approximately 33% 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.

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

	Including Price Revisions			Excluding Price Revisions(1)		
	2013	2012	2011	2013	2012	2011
Reserve Replacement Ratios(2)	476%	47%	416%	464%	298%	418%
Proved Developed Reserves(3)	33%	46%	48%	33%	46%	48%
Proved Undeveloped Reserves(3)	67%	54%	52%	67%	54%	52%
Reserve Replacement Costs(2)(4)($/Boe)	$ 12.62	$ 67.56	$ 8.52	$ 12.95	$ 10.74	$ 8.46

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

(2) No acquisitions are included in our reserve replacement ratio or reserve replacement costs 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.

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, 2013.

	Including Price Revisions	Excluding Price Revisions
	Three years ended December 31, 2013 ($/Boe)	
Reserve Replacement Costs	$13.94	$10.52

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Results of Operations

The information below reflects financial results for EP Energy Corporation for the year ended December 31, 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 new parent EP Energy Corporation) to December 31, 2012, for the period from January 1 to May 24, 2012 and for the year ended December 31, 2011. Beginning with the Acquisition on May 24, 2012, our financial results 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 2013 and the pending 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 future periods are 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, 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) and (ii) results from the combined year ended December 31, 2012 with results for the year ended December 31, 2011, excluding divested assets. 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.

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

	Year-to-Date Periods			
	2013	2012		2011
	Successor		Predecessor	
	Year ended December 31,	February 14 to December 31	January 1 to May 24	Year ended December 31,
	(in millions)			
Operating revenues:				
Oil and condensate	$ 1,283	$ 523	$ 310	$ 513
Natural gas	331	234	228	901
NGLs	78	32	29	58
Total physical sales	1,692	789	567	1,472
Financial derivatives	(52)	(62)	365	284
Total operating revenues	1,640	727	932	1,756
Operating expenses:				
Natural gas purchases	25	19		
Transportation costs	92	51	45	85
Lease operating expenses	163	71	80	177
General and administrative expenses	229	358	69	185
Depreciation, depletion and amortization	618	209	307	579
Impairment and ceiling test charges	2	1	62	6
Exploration expense	45	43		
Taxes, other than income taxes	86	41	31	76
Total operating expenses	1,260	793	594	1,108
Operating income (loss)	380	(66)	338	648
Loss from unconsolidated affiliates	(13)	(1)	(5)	(7)
Other income	1		2	1
Loss on extinguishment of debt	(9)	(14)		
Interest expense	(354)	(219)	(14)	(14)
Income (loss) from continuing operations before income tax	5	(300)	321	628
Income tax expense	63		134	243
(Loss) income from continuing operations	(58)	(300)	187	385
Income (loss) from discontinued operations, net of tax	508	44	(9)	(123)
Net income (loss)	$ 450	$ (256)	$ 178	$ 262

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the year ended December 31, 2013, for each of the successor and predecessor periods in 2012, and for the predecessor 2011 period. We present (i) average realized prices based on physical sales of oil and condensate, 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			
	2013	2012	2012	2011
	Successor	Successor	Predecessor	Predecessor
	Year ended December 31	February 14 to December 31	January 1 to May 24	Year ended December 31
	(in millions)			
Operating revenues(1):				
Oil and condensate	$ 1,283	$ 523	$ 310	$ 513
Natural gas	331	234	228	901
NGLs	78	32	29	58
Total physical sales	1,692	789	567	1,472
Financial derivatives	(52)	(62)	365	284
Total operating revenues	$ 1,640	$ 727	$ 932	$ 1,756
Volumes(1):				
Oil and condensate				
Consolidated volumes (MBbls)	13,515	5,896	3,105	5,680
Unconsolidated affiliate volumes (MBbls)(2)	197	167	115	306
Natural gas				
Consolidated volumes (MMcf)	92,239	79,429	94,847	230,669
Unconsolidated affiliate volumes (MMcf)(2)	10,050	9,242	6,310	16,881
NGLs				
Consolidated volumes (MBbls)	2,541	940	673	1,068
Unconsolidated affiliate volumes (MBbls)(2)	327	288	190	556
Equivalent volumes				
Consolidated MBoe	31,429	20,074	19,586	45,193
Unconsolidated affiliate MBoe(2)	2,199	1,995	1,357	3,675
Total Combined MBoe	33,628	22,069	20,943	48,868
Consolidated MBoe/d	86	91	135	124
Unconsolidated affiliate MBoe/d(2)	6	9	9	10
Total Combined MBoe/d	92	100	144	134
Consolidated prices per unit(3):				
Oil and condensate				
Average realized price on physical sales ($/Bbl)	$ 94.97	$ 88.80	$ 99.76	$ 90.22
Average realized price, including financial derivatives ($/Bbl)(4)	$ 97.72	$ 95.92	$ 99.61	$ 88.98
Natural gas				
Average realized price on physical sales ($/Mcf)	$ 3.31	$ 2.70	$ 2.40	$ 3.91
Average realized price, including financial derivatives ($/Mcf)(4)	$ 3.02	$ 4.90	$ 4.15	$ 5.37

NGLs				
Average realized price on physical sales ($/Bbl)	$ 30.81	$ 33.83	$ 42.94	$ 53.50

(1) Operating revenues and volumes in the successor periods do not include amounts associated with domestic natural gas assets sold and all periods do not include Brazilian operations held for sale at December 31, 2013, as such amounts are included as discontinued operations.

(2) In September 2013, we sold our equity investment in Four Star.

(3) Natural gas prices for the year ended December 31, 2013 and from February 14 to December 31, 2012 are calculated including a reduction of $25 million and $19 million, respectively, for natural gas purchases associated with managing our physical sales.

(4) The successor periods for the year ended December 31, 2013 and from February 14 to December 31, 2012 include approximately $28 million of cash paid and approximately $175 million of cash received for the settlement of natural gas financial derivatives. The predecessor periods from January 1 to May 24, 2012 and for the year ended December 31, 2011 include approximately $165 million and $338 million, respectively, of cash received for the settlement of natural gas financial derivatives. The successor periods for the year ended December 31, 2013 and from February 14 to December 31, 2012 include approximately $29 million and $45 million, respectively, of cash receipts for the settlement of crude oil derivative contracts. The year ended December 31, 2011 included approximately $7 million, of cash paid 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, 2013, overall increases in physical sales were due primarily to oil volume growth from our Eagle Ford and Wolfcamp drilling programs, partially offset by decreases in natural gas sales volumes primarily due to a decrease in volumes in Haynesville.

Oil and condensate sales for the year ended December 31, 2013, compared to the combined year ended December 31, 2012, increased by $450 million (54%), mainly from growth in our Eagle Ford drilling program. In 2013, Eagle Ford oil and condensate production volumes increased by 75% (10 MBbls/d) compared with the combined year ended December 31, 2012. In addition, Wolfcamp oil and condensate production volumes increased by 168% (2 MBbls/d). For the combined year ended December 31, 2012, oil and condensate sales increased by $320 million compared to 2011 attributable to a 62% increase (11 MBbls/d) in consolidated oil volumes in our Eagle Ford, Wolfcamp and Altamont core areas.

Natural gas sales for the year ended December 31, 2013 and for the successor period from February 14 to December 31, 2012, were $331 million and $234 million, respectively. For the predecessor period from January 1 to May 24, 2012, natural gas sales were $228 million (including approximately $88 million of natural gas sales related to divested assets). Natural gas sales (excluding amounts related to divested assets) decreased for the year ended December 31, 2013 compared with the combined year ended December 31, 2012, due to the decrease in volumes in Haynesville, partially offset by higher natural gas prices. During the first quarter of 2012, we suspended our drilling program in the Haynesville Shale due to low natural gas prices. Natural gas sales (excluding amounts related to divested assets in both periods) decreased for the combined year ended December 31, 2012 compared with 2011 primarily due to lower natural gas prices.

NGLs sales increased for the year ended December 31, 2013 compared with the combined year ended December 31, 2012. Although average realized prices for the year ended December 31, 2013 decreased compared to the same period in 2012; this was more than offset by an increase in 2013 in NGLs volumes over 2012 primarily as a result of our Eagle Ford drilling program. Eagle Ford NGLs volumes increased by 128% (3 MBbls/d) over the year ended December 31, 2012. For the combined year ended December 31, 2012, NGLs sales increased by $3 million compared to 2011 primarily again as a result of Eagle Ford.

As of December 31, 2013, the NYMEX spot price of a barrel of oil was $98.42 versus the NYMEX spot price of natural gas of $4.23, or a ratio of 23 to 1. We have and will continue to target increases in our oil volumes due to this value difference, but we also expect volumes of natural gas to decline with less capital focus in this area. Growth in our revenue will largely be impacted by our ability to grow our oil volumes and by changes in oil prices.

Gains or losses on financial derivatives. We record gains or losses due to cash settlements and changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. During the year ended December 31, 2013, we recorded $52 million of derivative losses compared to a derivative gain of $303 million during the combined year ended December 31, 2012. Realized and unrealized gains for the combined year ended December 31, 2012 increased by $19 million compared to 2011.

Operating Expenses

Transportation costs. Transportation costs for the year ended December 31, 2013 and for the successor period from February 14 to December 30, 2012 were $92 million and $51 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $45 million (including $18 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 2011 due to oil transportation costs associated with Eagle Ford as a result of our production growth and new transportation contracts in that area.

Lease operating expense. Lease operating expense for the year ended December 31, 2013 and for the successor period from February 14 to December 31, 2012 were $163 million and $71 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $80 million (including $31 million of lease operating expense related to divested assets). Total lease operating expense (excluding amounts related to the divested assets) for the year ended December 31, 2013 increased as compared to the combined year ended December 31, 2012 due to increased equipment and chemical costs in our Eagle Ford play and higher maintenance, repair and power costs. Lease operating expense (excluding amounts related to divested assets) for the combined year ended December 31, 2012 increased $57 million compared to 2011 due to increased water disposal, equipment and chemical costs in Eagle Ford as activity ramped up in that area.

General and administrative expenses. General and administrative expenses for the year ended December 31, 2013 decreased $198 million compared to the combined successor/predecessor year ended December 31, 2012. The decrease was primarily due to 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

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advisory service charges reflected for the year ended December 31, 2013. On January 1, 2014, we paid a non-refundable quarterly installment of $6.25 million under an amended and restated management fee agreement. In connection with our initial public offering on January 23, 2014, the amended and restated management fee agreement was terminated and we paid a transaction fee of $83 million to our Sponsors. 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. General and administrative expenses for the combined year ended December 31, 2012 increased $242 million compared to 2011 primarily due to the transition and restructuring costs of $221 million in 2012 in conjunction with the Acquisition.

Depreciation, depletion and amortization expense. Our depreciation, depletion and amortization costs increased during the year ended December 31, 2013 compared with 2012 due to the ongoing development of higher cost oil programs (e.g. Eagle Ford and Wolfcamp) as well as the step up in 2012 in the book basis of our oil and natural gas assets as a result of the Acquisition. For the year ended December 31, 2012 depreciation, depletion and amortization decreased compared to 2011 due to an average lower depletion rate following the application of the successful efforts method of accounting for oil and natural gas properties, partially offset by higher production volumes. Due to the ongoing development of higher cost liquids programs, we expect our depletion rate will continue to increase as compared to our current levels. Our average depreciation, depletion and amortization costs per unit for the year-to-date periods were:

	Year-to-Date Periods			
	2013	2012		2011
	Successor		Predecessor	
	Year ended December 31	February 14 to December 31	January 1 to May 24	Year ended December 31
Depreciation, depletion and amortization ($/Boe)(1)	$ 19.65	$ 10.42	$ 15.66	$ 12.81

(1) Includes $0.11 per Boe for the year ended December 31, 2013, $0.13 per Boe for the successor period from February 14 to December 31, 2012, $0.23 per Boe and $0.25 per Boe for the predecessor period from January 1 to May 24, 2012 and the year ended December 31, 2011 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, sustained lower oil and/or natural gas prices from present levels could result in an impairment of the carrying value of our proved properties in the future.

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. During the year ended December 31, 2011 the predecessor recorded a non-cash charge of approximately $6 million impairment of certain oil field related equipment and supplies.

Exploration expense. For the year ended December 31, 2013 we recorded $45 million of exploration expense compared to $43 million for the successor period from February 14 to December 31, 2012. 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, 2013 is $36 million of amortization of unproved leasehold costs.

Taxes, other than income taxes. Taxes, other than income taxes for the year ended December 31, 2013 and for the successor period from February 14 to December 31, 2012, were $86 million and $41 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $31 million (including approximately $9 million of taxes, other than income taxes related to divested assets). Production taxes increased in 2013 over the combined period in 2012 due to higher production volumes. 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. Taxes, other than income taxes (excluding amounts related to divested assets) for the combined year ended December 31, 2012 increased compared to 2011 primarily due to higher severance and ad valorem taxes associated with higher oil production volumes and property values from activity in our oil producing areas.

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

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ceiling test charges and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition and restructuring costs, transaction, management and other fees paid to the Sponsors (which terminated on January 23, 2014), non-cash compensation expense 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:

[redacted]								
Total continuing operating expenses	$ 1,260	$ 40.11	$ 793	$ 39.52	$ 594	$ 30.32	$ 1,108	$ 24.51
Depreciation, depletion and amortization	(618)	(19.65)	(209)	(10.42)	(307)	(15.66)	(579)	(12.81)
Transportation costs	(92)	(2.95)	(51)	(2.55)	(45)	(2.32)	(85)	(1.87)
Exploration expense	(45)	(1.43)	(43)	(2.15)				
Natural gas purchases	(25)	(0.80)	(19)	(0.97)				
Impairment and ceiling test charges	(2)	(0.06)	(1)	(0.06)	(62)	(3.15)	(6)	(0.16)
Total continuing cash operating costs	478	15.22	470	23.37	180	9.19	438	9.67
Transition/restructuring costs, non-cash compensation expense and other(2)	(65)	(2.07)	(266)	(13.24)	(11)	(0.58)	(27)	(0.58)
Total adjusted cash operating costs and adjusted per-unit cash costs(2)	$ 413	$ 13.15	$ 204	$ 10.13	$ 169	$ 8.61	$ 411	$ 9.09
Total equivalent volumes (MBoe)(3)	31,429		20,074		19,586		45,193	

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

(2) 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 (inception) 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 year ended December 31, 2011 includes $6 million of restructuring costs associated with the closure of our Denver office and $21 million of non-cash compensation expense.

(3) Excludes volumes associated with Four Star.

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

	Year-to-Date Periods			
	2013	2012		2011
	Successor		Predecessor	
	Year ended December 31	February 14 to December 31	January 1 to May 24	Year ended December 31
Average cash operating costs ($/Boe)				
Lease operating expenses	$ 5.19	$ 3.53	$ 4.07	$ 3.89
Production taxes(1)	2.90	1.98	1.79	1.53
General and administrative expenses	7.29	17.80	3.53	4.10
Taxes, other than production and income taxes	(0.16)	0.06	(0.20)	0.15
Total cash operating costs	15.22	23.37	9.19	9.67
Transition/restructuring costs, non-cash compensation expense and other	(2.07)	(13.24)	(0.58)	(0.58)
Total adjusted cash operating costs	$ 13.15	$ 10.13	$ 8.61	$ 9.09

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(1) Production taxes include ad valorem and severance taxes which increased in 2013 primarily due to higher ad valorem taxes associated with our oil producing areas.

Other Income Statement Items.

Loss from unconsolidated affiliates. For the year ended December 31, 2013 we recorded losses on our equity investees 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, 2013 we recorded $9 million in losses of extinguishment of debt for 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 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, 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. In January 2014, we repaid our senior PIK toggle note and a portion of RBL borrowings with proceeds from our initial public offering.

Income taxes. The effective tax rate for the year ended December 31, 2013 was significantly higher 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 the period. 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 2013 includes a $468 million gain on the sale of assets during 2013 and 2011 includes a non-cash charge of approximately $152 million related to our Brazil oil and natural gas operations.

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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), impairment and/or ceiling test charges, equity earnings from Four Star due to its sale in 2013, non-cash compensation expense, transition and restructuring costs, transaction, management and other fees paid to our Sponsors, costs associated with our initial public offering and losses or gains on extinguishment of debt. 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 (i) additional information to evaluate our ability to service debt adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) an important supplemental indicator of the operational performance of our business, (iii) an additional criterion for evaluating our performance relative to our peers, (iv) additional information to measure our liquidity (before cash capital requirements and working capital needs) and (v) 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 income (loss) from continuing operations, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP.

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

	Successor		Predecessor	
	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011
	(in millions)			
(Loss) income from continuing operations	$ (58)	$ (300)	$ 187	$ 385
Income tax expense	63		134	243
Interest expense, net of capitalized interest	354	219	14	14
Depreciation, depletion and amortization	618	209	307	579
Exploration expense	45	43		
EBITDAX	1,022	171	642	1,221
Mark-to-market on financial derivatives(1)	52	62	(365)	(284)
Cash settlements and premiums on financial derivatives(2)	10	217	165	331
Impairments and ceiling test charges	2	1	62	6
Transition and restructuring costs(3)	7	215	5	6
Loss from unconsolidated affiliate(4)	13	1	5	7
Non-cash compensation expense(5)	31	35	6	21
Management and other fees(6)	26	16		
Initial public offering costs(7)	1			
Loss on extinguishment of debt(8)	9	14		
Adjusted EBITDAX	1,173	732	520	1,308
Less: Adjusted EBITDAX divested assets(9)		5	64	460
Pro Forma Adjusted EBITDAX	$ 1,173	$ 727	$ 456	$ 848

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

(2) Represents actual cash settlements received/(paid) related to financial derivatives, including cash premiums. For the year ended December 31, 2013 we received $9 million of cash premiums 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 year ended December 31, 2011.

(3) Reflects the transaction costs paid as part of the Acquisition in 2012 and severance costs incurred in connection with divested assets in 2013 and the closure of our office in Denver in 2011.

(4) 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.

(5) Represents the non-cash portion of compensation expense.

(6) Represents the annual management fee of $25 million and other fees paid to affiliates of the Sponsors and other investors.

(7) Represents the costs incurred related to our initial public offering.

(8) Represents the loss on extinguishment of debt recorded related to re-pricing of the term loan and redetermination of the RBL Facility.

(9) Consists of Adjusted EBITDAX related to assets that have been divested, including our (i) CBM, South Texas and Arklatex assets (which are treated as discontinued operations after May 2012), (ii) Gulf of Mexico assets, (iii) Blue Creek West, Minden and Powder River operations and (iv) Catapult operations and Altamont processing plant and related gathering systems.

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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. We currently maintain a borrowing base on our RBL Facility of $2.5 billion, subject to semi-annual redetermination. As of December 31, 2013, our available liquidity was approximately $2.25 billion, including approximately $2.2 billion of additional borrowing capacity available under the RBL Facility.

During 2013, we entered into purchase and sale agreements for the sale of CBM properties (Raton, Arkoma and Black Warrior basins), the majority of our Arklatex natural gas properties, our natural gas properties in South Texas and our approximate 49% equity interest in Four Star, receiving total consideration of approximately $1.5 billion. While we have experienced lower cash flow from operations compared with prior years as a result of these asset divestitures, we used the proceeds, among other items, to pay down debt and invest incremental capital in our core oil programs to generate higher return oil production growth.

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 $664 million. We used the proceeds to repay our PIK toggle note and a portion of our outstanding RBL Facility balance.

We believe we have sufficient liquidity from our cash flows from operations, combined with availability under the RBL Facility and available cash, to fund our capital program, current obligations, and projected working capital requirements in 2014. 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 have attempted to mitigate certain of these risks. For example, we enter into oil and gas derivative contracts to reduce the financial impact of downward commodity price movements on a substantial portion of our anticipated production. These contracts have been effective in providing greater cash flow certainty. Additionally, we occasionally enter into transactions to supplement the prices we receive through our hedging programs that involve the receipt or payment of premiums. These transactions are usually short term in nature (less than one year) and during 2013, we received $9 million in premiums on such transactions, substantially all of which settled during 2013. We could be required to take additional future actions if necessary to address further changes in the financial or commodity markets.

Capital Expenditures. For 2014, we expect our total capital budget will be approximately $2 billion, substantially all of which will be expended in our core oil programs. Our capital expenditures and our average drilling rigs for the twelve months ended December 31, 2013 were:

		Capital Expenditures (in millions)	Average Drilling Rigs
Eagle Ford Shale	$	1,191	5.5
Wolfcamp Shale		505	3.0
Altamont		207	2.5
Haynesville Shale		1	
Other		21	
Total capital expenditures(1)	$	1,925	11.0

(1) Excludes capital expenditures of $9 million from domestic assets sold in the third quarter of 2013.

Long-Term Debt. As of December 31, 2013, our long-term debt is approximately $4.4 billion, comprised of $3.1 billion in senior notes due in 2019, 2020 and 2022, $644 million in senior secured term loans with maturity dates in 2018 and 2019, $382 million in senior PIK toggle note due in 2017, and $295 million outstanding under the RBL Facility expiring in 2017. While our debt and interest expense is significantly higher than in predecessor periods due to debt incurred with the Acquisition, we have reduced our debt utilizing proceeds from our 2013 asset divestitures and our initial public offering. For additional details on our long-term debt, including restrictive covenants under our debt agreements, see Part II, Item 8, Financial Statements and Supplementary Data , Note 8.

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

	Successor		Predecessor	
	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011
	(in millions)			
Cash Flow from Operations				
Operating activities				
Net income (loss)	$ 450	$ (256)	$ 178	$ 262
Impairment and ceiling test charges	46	1	62	158
Gain on sale of assets	(468)			
Other income adjustments	863	351	537	973
Change in other assets and liabilities	69	353	(197)	33
Total cash flow from operations	$ 960	$ 449	$ 580	$ 1,426
Other Cash Inflows				
Investing activities				
Net proceeds from the sale of assets and investments	$ 1,451	$ 110	$ 9	$ 612
Financing activities				
Proceeds from debt	1,880	5,825	215	2,030
Contributions	17	3,323	960	
	1,897	9,148	1,175	2,030
Total cash inflows	$ 3,348	$ 9,258	$ 1,184	$ 2,642
Cash Outflows				
Investing activities				
Capital expenditures	$ 1,924	$ 877	$ 636	$ 1,591
Cash paid for acquisitions	2	7,126	1	22
Increase in note receivable with parent				236
	1,926	8,003	637	1,849
Financing activities				
Repayment of debt	2,190	1,139	1,065	1,480
Net change in note payable with parent company and affiliates				781
Member distribution	205	337		
Debt issuance costs	5	159		7
	2,400	1,635	1,065	2,268
Total cash outflows	$ 4,326	$ 9,638	$ 1,702	$ 4,117
Net change in cash and cash equivalents	$ (18)	$ 69	$ 62	$ (49)

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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, 2013, for each of the periods presented:

	2014	2015 - 2016	2017 - 2018 (in millions)	Thereafter	Total
Long-term financing obligations:					
Principal	$	$	$ 1,178	$ 3,250	$ 4,428
Interest	332	673	614	369	1,988
Liabilities from derivatives	35				35
Operating leases	12	22	8		42
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	81	144	152	219	596
Other obligations	62	51	50	135	298
Total contractual obligations	$ 522	$ 890	$ 2,002	$ 3,973	$ 7,387

Long-term Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt and (ii) current market interest rates and the contractual credit spread for variable rate debt. In 2014, we repaid our senior PIK toggle note.

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

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

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

- *Volume and Transportation Commitments.* Included in these amounts are commitments for volume deficiency contracts and demand charges for firm access to natural gas transportation as well as firm oil capacity. Subsequent to December 31, 2013, we entered into an additional transportation commitment for approximately $66 million which will be incurred over the next five years.

- *Other Obligations.* Included in these amounts are commitments for drilling, completions and seismic activities for our operations and various other maintenance, engineering, procurement, construction contracts and our management fee agreement. 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. Prior to 2014, our affiliates were party to a management fee agreement requiring the payment of an annual management fee of $25 million to our Sponsors which is reflected annually in the table above through May 24, 2024. On January 1, 2014, we paid a $6.25 million installment under that agreement. The management fee agreement terminated later in January 2014 in connection with our initial public offering, and accordingly no further management fee payments will be required.

Commitments and Contingencies

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

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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, 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 to determine if impairment of such properties is necessary. Our evaluation 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 to determine recoverability. 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, forward commodity prices based on published commodity price curves as of the date of the estimate, adjusted for geographical location 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. Leasehold acquisition costs associated with non-producing areas are assessed for impairment by major prospect area based on our current drilling plans which could change in the future and result in impairments of unproved property. A majority of the Company s unproved property costs are associated with properties acquired in the Eagle Ford and Wolfcamp shales. 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 programs. In 2013 and from the Acquisition (May 25, 2012) to December 31, 3012, we did not record any impairments of our oil and gas properties included in continuing operations.

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. Costs in 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 as a result of the decision to end exploration activities in Egypt and a $6 million impairment of certain oil field related equipment and supplies for the period from January 1, 2012 through May 24, 2012 and for the year ended 2011, respectively.

Our 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 or ceiling test charges on our income

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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 ensure forecasts of operating expenses, netback prices, production trends and development timing 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, 2013, 67% of our total proved reserves were undeveloped and 3% were developed, but non-producing. The data for a given field may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, material revisions to existing reserve estimates occur from time to time. In addition, the subjective decisions and variances in available data for various fields increase the likelihood of significant changes in these estimates.

Asset Retirement Obligations. The accounting guidance for future abandonment costs requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Future abandonment costs include 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. As of December 31, 2013, our net asset retirement liability was approximately $53 million (excluding $37 million related to Brazil classified as discontinued operations).

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.

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, 2013:

		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)	$ 105	$ (349)	$ (454)	$ 551	$ 446

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.

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Deferred Taxes and Uncertain Income Tax Positions. As a result of our Corporate Reorganization, 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 and uncertain tax positions which involve the exercise of significant judgment which could change and impact our financial condition or results of operations.

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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
- structured contracts, which may involve a variety of the above characteristics.

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

For information regarding changes in commodity prices and interest rates during 2013, 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.

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Sensitivity Analysis. 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, discount rates and credit rates at December 31, 2013:

		Oil and Natural Gas Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Price impact(1)	$ 105	$ (349)	$ (454)	$ 551	$ 446

		Oil and Natural Gas Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Discount Rate(2)	$ 105	$ 103	$ (2)	$ 107	$ 2
Credit rate(3)	$ 105	$ 104	$ (1)	$ 105	$

(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.

[redacted]										
Fixed rate long-term debt	$	$	$	$ 382	$	$ 3,100	$ 3,482	$ 3,896	$ 3,449	$ 3,779
Average interest rate	8.6%	8.6%	8.6%	8.6%	8.6%	8.3%				
Variable rate long-term debt	$	$	$	$ 295	$ 495	$ 149	$ 939	$ 945	$ 1,246	$ 1,260
Average interest rate	3.3%	3.3%	3.3%	3.5%	4.0%	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

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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, 2013. 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 (1992 framework). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2013. The effectiveness of our internal control over financial reporting as of December 31, 2013 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 Shareholders of EP Energy Corporation

We have audited EP Energy Corporation s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 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, 2013, 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, 2013 and 2012 (Successor), and the related consolidated statements of income, comprehensive income, cash flows and changes in equity for the year ended December 31, 2013 (Successor), the period from February 14, 2012 to December 31, 2012 (Successor), the period from January 1, 2012 to May 24, 2012 (Predecessor) and for the year ended December 31, 2011 (Predecessor) and our report dated February 27, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2014

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders of EP Energy Corporation

We have audited the accompanying consolidated balance sheets of EP Energy Corporation as of December 31, 2013 and 2012 (Successor), and the related consolidated statements of income, comprehensive income, cash flows and changes in equity for the year ended December 31, 2013 (Successor), the period from February 14, 2012 to December 31, 2012 (Successor), the period from January 1, 2012 to May 24, 2012 (Predecessor) and for the year ended December 31, 2011 (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. The financial statements of Four Star Oil & Gas Company (a corporation in which the Company had a 49 percent interest), have been audited by other auditors whose report has been furnished to us, and our opinion on the consolidated financial statements, insofar as it relates to the amounts included from Four Star Oil & Gas Company for the year ended December 31, 2011, is based solely on the report of other auditors. In the consolidated financial statements, earnings from unconsolidated affiliate includes approximately $29 million for the year ended December 31, 2011, from Four Star Oil & Gas Company.

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 and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EP Energy Corporation at December 31, 2013 and 2012 (Successor), and the consolidated results of its operations and its cash flows for the year ended December 31, 2013 (Successor), the period from February 14, 2012 to December 31, 2012 (Successor), the period from January 1, 2012 to May 24, 2012 (Predecessor) and for the year ended December 31, 2011 (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, 2013 (Successor), based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework), and our report dated February 27, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Houston, Texas
February 27, 2014

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and the Stockholders of

Four Star Oil & Gas Company:

In our opinion, the consolidated balance sheet and the related consolidated statements of income, of stockholders equity and of cash flows (not presented separately herein) present fairly, in all material respects, the financial position of Four Star Oil & Gas Company and its subsidiary (the Company) at December 31, 2011, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. 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 audit. We conducted our audit of these statements 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As described in Notes 4 and 5 to the consolidated financial statements, the Company has significant transactions with affiliated companies. Because of these relationships, it is possible that the terms of these transactions are not the same as those that would result from transactions among wholly unrelated parties.

/s/PricewaterhouseCoopers LLP

February 24, 2012
Houston, Texas

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

(In millions)

	Successor		Predecessor	
	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011
Operating revenues				
Oil and condensate	$ 1,283	$ 523	$ 310	$ 513
Natural gas	331	234	228	901
NGLs	78	32	29	58
Financial derivatives	(52)	(62)	365	284
Total operating revenues	1,640	727	932	1,756
Operating expenses				
Natural gas purchases	25	19		
Transportation costs	92	51	45	85
Lease operating expense	163	71	80	177
General and administrative	229	358	69	185
Depreciation, depletion and amortization	618	209	307	579
Impairment and ceiling test charges	2	1	62	6
Exploration expense	45	43		
Taxes, other than income taxes	86	41	31	76
Total operating expenses	1,260	793	594	1,108
Operating income (loss)	380	(66)	338	648
Loss from unconsolidated affiliate	(13)	(1)	(5)	(7)
Other income	1		2	1
Loss on extinguishment of debt	(9)	(14)		
Interest expense				
Third party	(354)	(219)	(14)	(9)
Affiliated				(5)
Income (loss) from continuing operations before income taxes	5	(300)	321	628
Income tax expense	63		134	243
(Loss) income from continuing operations	(58)	(300)	187	385
Income (loss) from discontinued operations, net of tax	508	44	(9)	(123)
Net income (loss)	$ 450	$ (256)	$ 178	$ 262
Basic and diluted earnings (loss) per share				
Loss from continuing operations	(0.28)	(1.44)		
Discontinued operations, net of tax	2.44	0.21		
Net income (loss)	2.16	(1.23)		
Basic and diluted weighted average common shares outstanding	208,674,975	208,674,975		

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Successor		Predecessor	
	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011
Net income (loss)	$ 450	$ (256)	$ 178	$ 262
Cash flow hedging activities:				
Reclassification adjustment(1)			3	7
Comprehensive income (loss)	$ 450	$ (256)	$ 181	$ 269

(1) Reclassification adjustments are stated net of tax. Taxes recognized for the predecessor periods related to January 1, 2012 to May 24, 2012 and the year ended December 31, 2011 are $2 million and $4 million, respectively.

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 51	$ 69
Accounts receivable		
Customer, net of allowance of less than $1 in 2013 and 2012	239	158
Other, net of allowance of $2 for 2013 and $1 for 2012	44	14
Materials and supplies	20	16
Derivative instruments	47	108
Assets of discontinued operations	88	1,034
Deferred income taxes	28	
Prepaid assets	12	10
Total current assets	529	1,409
Property, plant and equipment, at cost		
Oil and natural gas properties	8,371	6,513
Other property, plant and equipment	63	52
	8,434	6,565
Less accumulated depreciation, depletion and amortization	818	214
Total property, plant and equipment, net	7,616	6,351
Other assets		
Investment in unconsolidated affiliate		220
Derivative instruments	97	88
Assets of discontinued operations		93
Unamortized debt issue costs	116	140
Other	8	5
	221	546
Total assets	$ 8,366	$ 8,306

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

(In millions)

	December 31, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 140	$ 98
Other	392	303
Income tax payable	2	
Derivative instruments	35	17
Accrued interest	54	57
Asset retirement obligations	3	4
Liabilities of discontinued operations	91	211
Other accrued liabilities	63	74
Total current liabilities	780	764
Long-term debt	4,421	4,695
Other long-term liabilities		
Derivative instruments		14
Deferred income taxes	171	
Liabilities of discontinued operations		42
Asset retirement obligations	50	40
Other	7	3
Total non-current liabilities	4,649	4,794
Commitments and contingencies (Note 9)		
Members /Stockholder s equity		
Member s equity		2,748
Class A shares, $0.01 par value; 550,000,000 authorized, 208,674,975 issued and outstanding at December 31, 2013		
Class B shares, $0.01 par value; 878,304 authorized, issued and outstanding at December 31, 2013		
Preferred stock, $0.01 par value; 50,000,000 authorized, none issued or outstanding		
Additional paid-in capital	2,832	
Retained earnings	105	
Total members /stockholder s equity	2,937	2,748
Total liabilities and equity	$ 8,366	$ 8,306

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Successor		Predecessor	
	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011
Cash flows from operating activities				
Net income (loss)	$ 450	$ (256)	$ 178	$ 262
Adjustments to reconcile net income (loss) to net cash provided by operating activities				
Depreciation, depletion and amortization	666	268	319	612
Gain on sale of assets	(468)			
Deferred income tax expense	67	1	199	304
Loss from unconsolidated affiliates, net of cash distributions	37	15	12	53
Impairment and ceiling test charges	46	1	62	158
Loss on extinguishment of debt	9	14		
Amortization of equity compensation expense	22	17		
Non-cash portion of exploration expense	39	23		
Other non-cash income items	23	13	7	4
Asset and liability changes				
Accounts receivable	(50)	(73)	132	(20)
Accounts payable	80	66	(56)	(67)
Derivative instruments	56	281	(201)	47
Accrued interest	(3)	57	(1)	(1)
Other asset changes	(13)	(18)	(7)	95
Other liability changes	(1)	40	(64)	(21)
Net cash provided by operating activities	960	449	580	1,426
Cash flows from investing activities				
Capital expenditures	(1,924)	(877)	(636)	(1,591)
Net proceeds from the sale of assets and investments	1,451	110	9	612
Cash paid for acquisitions, net of cash acquired	(2)	(7,126)	(1)	(22)
Increase in note receivable with parent				(236)
Net cash used in investing activities	(475)	(7,893)	(628)	(1,237)
Cash flows from financing activities				
Proceeds from long term debt	1,880	5,825	215	2,030
Repayment of long term debt	(2,190)	(1,139)	(1,065)	(1,480)
Distributions to members	(205)	(337)		
Contributed member equity		3,323		
Contributions from members	17		960	
Change in note payable with parent				(781)
Debt issuance costs	(5)	(159)		(7)
Net cash (used in) provided by financing activities	(503)	7,513	110	(238)
Change in cash and cash equivalents	(18)	69	62	(49)
Cash and cash equivalents				
Beginning of period	69		25	74
End of period	$ 51	$ 69	$ 87	$ 25

Supplemental cash flow information				
Interest paid, net of amounts capitalized	$ 305	$ 145	$ 7	$ 9
Income tax payments (refunds)	16	2	2	(158)

See accompanying notes.

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EP ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In millions, except predecessor share amounts)

	Stockholder s Equity										
			Class A Stock		Class B Stock		Additional		Accumulated Other	Total	
	Shares	Common Stock	Shares	Amount	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income	Stockholder s Equity	Members Equity
Predecessor											
Balance at January 1, 2011	1,000	$		$		$	$ 4,816	$ (1,738)	$ (11)	$	$ 3,067
Distribution to parent							(236)				(236)
Other									7		7
Net income								262			262
Balance at December 31, 2011	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)
Equity compensation expense											18
Net loss											(256)
Balance at December 31, 2012		$		$		$	$	$	$	$	$ 2,748
Compensation expense											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 C-Corp conversion							(78)			(78)	
Compensation expense							7			7	
Net income								105		105	
Balance at December 31, 2013		$	209	$	0.9	$	$ 2,832	$ 105	$	$ 2,937	$

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

Prior to August 30, 2013, we conducted our activities through EPE Acquisition, LLC, a holding company formed on February 14, 2012. On August 30, 2013, we reorganized our structure to form EP Energy Corporation, a new corporate holding Company (Corporate Reorganization). Prior to the Corporate Reorganization, 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 10). 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. We refer to (i) these direct and indirect holders of Class A common stock and their permitted transferees as the Legacy Class A Stockholders, (ii) the holder of the Class B common stock and its permitted transferees as the Legacy Class B Stockholder and (iii) the Legacy Class A Stockholders and the Legacy Class B Stockholder together as the Legacy Stockholders. As a result of the Corporate Reorganization, EP Energy Corporation owns, directly, or indirectly, 100% of the equity interests in EPE Acquisition, LLC. The Corporate Reorganization was accounted for as a transaction between entities under common control and was recorded at historical cost.

EPE Acquisition, LLC was originally formed as a Delaware limited liability company on February 14, 2012 by investment funds affiliated with and managed by Apollo Global Management LLC (together with its subsidiares, Apollo) and other private equity investors (collectively, the Sponsors) as a company with no independent operations. EPE Acquisition, LLC, through its wholly-owned subsidiaries, owns the common stock of EP Energy Bondco Inc. and the units of EP Energy LLC (which owns 100 percent of EP Energy Global LLC). On May 24, 2012, the Sponsors acquired EP Energy Global LLC (formerly known as EP Energy Corporation and EP Energy, L.L.C. after its conversion into a Delaware limited liability company) 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 entities acquired are engaged in the exploration for and the acquisition, development, and production of oil, natural gas and NGLs primarily in the United States, with international activities in Brazil. Hereinafter, for periods prior to the Acquisition, 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 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.

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, condensate, 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

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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. All historical successor periods have been adjusted to reflect these purchases and sales transactions on a gross basis.

As of December 31, 2013 and 2012, we had two customers that accounted for 10 percent or more of our total revenues. The predecessor period in 2012 had three customers, and for the year ended December 31, 2011, had one customer that 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, 2013 and 2012, we had less than $1 million, respectively, of restricted cash in other current assets to cover escrow amounts required for leasehold agreements in our domestic 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 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 to determine recoverability. 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, commodity prices based on published forward commodity price curves as of the date of the estimate, adjusted for geographical location 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.

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

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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 writedown 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 excludes 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.

Accounting for Long-Term Incentive Compensation

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

Environmental Costs, Legal and Other Contingencies

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

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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 on counterparties where we have a legal right of offset.

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

Income Taxes

We record current income taxes based on our estimates of current taxable income and provide for deferred income taxes to reflect estimated future income tax payments and receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. 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. We are also subject to the Texas margin tax and pay any liability directly to the state of Texas.

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.

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.

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2. Acquisitions and Divestitures

Acquisitions. 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 predecessor s revolving credit facility at that time. See Note 8 for additional discussion of debt.

The purchase transaction was accounted for under the acquisition method of accounting which requires, among other items, that assets and liabilities assumed be recognized on the consolidated balance sheet at their fair values as of the Acquisition date. Our consolidated balance sheet for all periods includes the following purchase price allocation based on available information to specific assets and liabilities assumed based on estimates of fair values and costs. There was no goodwill associated with the transaction.

Allocation of purchase price	**May 24, 2012 (in millions)**
Current assets	$ 587
Non-current assets	446
Property, plant and equipment	6,897
Current liabilities	(420)
Non-current liabilities	(297)
Total purchase price	$ 7,213

The unaudited pro forma information below for the years ended December 31, 2012 and 2011 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, 2011. 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	**Year ended December 31, 2011**
	(in millions)	
Operating Revenues	$ 1,659	$ 1,756
Net Income	143	454

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 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, substantially all of which had been paid as of December 31, 2012, were included as general and administrative expenses in our income statement.

Discontinued Operations. In June 2013, we entered into three separate agreements to sell our CBM properties located in the Raton, Black Warrior and Arkoma basins; our Arklatex conventional natural gas assets located in East Texas and North Louisiana and our legacy South Texas conventional natural gas assets. We completed these sales in 2013 for total consideration of approximately $1.3 billion and recorded a gain on the sale of approximately $468 million. In July 2013, we entered into a Quota Purchase Agreement to sell our Brazil operations which is expected to close in 2014. The sale is subject to Brazilian regulatory approval as well as certain other customary closing conditions. During 2013, we recorded $34 million of impairment charges ($10 million based on a comparison of the fair market value of our Brazil operations to its underlying carrying value when we entered into the purchase and sale agreement and $24 million to impair earnings subsequent to entering into that agreement). We estimated the fair value of our Brazil operations (representing a Level 3 fair value measurement) based primarily on sales proceeds expected to be received less estimates of retained liabilities.

In February 2014, we sold additional domestic natural gas assets in our Arklatex area for approximately $16 million and expect to record a gain on the sale of approximately $12 million in 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

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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.

Summarized operating results and financial position data of our discontinued operations were as follows (in millions):

	Successor		Predecessor	
	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011
Operating revenues	$ 297	$ 262	$ 46	$ 111
Operating expenses				
Natural gas purchases	19	23		
Transportation costs	18	22		
Lease operating expense	76	65	16	40
Depreciation, depletion and amortization	48	59	12	33
Impairment and ceiling test charges	44			152
Other expense	42	50	20	31
Total operating expenses	247	219	48	256
Gain on sale of assets	468			
Other (expense) income	(2)	3	(5)	(1)
Income (loss) from discontinued operations before income taxes	516	46	(7)	(146)
Income tax expense (benefit)	8	2	2	(23)
Income (loss) from discontinued operations	$ 508	$ 44	$ (9)	$ (123)

	December 31, 2013	December 31, 2012
Assets of discontinued operations		
Current assets	$ 26	$ 95
Property, plant and equipment, net	52	1,019
Other non-current assets	10	13
Total assets of discontinued operations	$ 88	$ 1,127
Liabilities of discontinued operations		
Accounts payable	$ 39	$ 84
Other current liabilities	10	16
Asset retirement obligations	37	146
Other non-current liabilities	5	7
Total liabilities of discontinued operations	$ 91	$ 253

Other Divestitures. 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 11 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.

During 2011, the predecessor sold non-core domestic oil and natural gas properties in several transactions from which they received proceeds that totaled approximately $612 million. The predecessor did not record a gain or loss on any of these sales.

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3. Impairment and Ceiling Test Charges

During 2013, we recorded a $2 million impairment on certain materials and supplies to reflect a market value lower than the underlying cost of those items. 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. For the predecessor period ended December 31, 2011, we recorded an impairment of certain oil field related materials and supplies of $6 million to reflect a market value lower than the underlying cost of those items.

Forward commodity prices can play a significant role in determining future impairments. Due to the current forecast of future oil, natural gas and NGLs prices and 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 from present levels could result in an impairment of the carrying value of our proved properties in the future.

4. Income Taxes

General. As a result of the Corporate Reorganization on August 30, 2013, we again became a corporation subject to federal and state income taxes. Accordingly, we began recording the effects of income taxes in our financial statements. As a result of the Corporate Reorganization, we have 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. As part of the Corporate Reorganization transaction, $17 million of cash was directly or indirectly contributed by the Sponsors to cover estimated federal and state income taxes from January 1, 2013 through August 30, 2013.

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, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011
	(in millions)			
Pretax Income (Loss)				
U.S.	$ 5	$ (300)	$ 384	$ 629

Foreign			(63)	(1)
	$ 5	$ (300)	$ 321	$ 628
Components of Income Tax Expense (Benefit)				
Current				
Federal	$ (2)	$	$ (62)	$ (79)
State			(3)	1
	(2)		(65)	(78)
Deferred				
Federal	58		188	302
State	7		11	19
	65		199	321
Total income tax expense	$ 63	$	$ 134	$ 243

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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 percent for the following reasons for the following periods:

	Successor		Predecessor	
	Year ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011
	(in millions, except rates)			
Income taxes at the statutory federal rate of 35%	$ 2	$ (105)	$ 112	$ 220
Increase (decrease)				
State income taxes, net of federal income tax effect	4		5	12
Partnership earnings not subject to tax	57	105		
Earnings from unconsolidated affiliates where we received or will receive dividends			(2)	(8)
Valuation allowances				15
Foreign income taxed at different rates			22	4
Other			(3)	
Income tax expense	$ 63	$	$ 134	$ 243

The effective tax rate for the successor period for the year ended December 31, 2013 was significantly higher than the statutory rate and the period from February 14 to December 31, 2012 was significantly lower than the statutory rate primarily due to only recording income tax expense subsequent to the Corporate Reorganization on August 30, 2013 and the level of pretax income during the period. 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. For the year ended December 31, 2011, the effective tax rate was higher than the statutory rate primarily due to valuation allowances recorded on deferred tax assets, partially offset by the impact of dividend exclusions on earnings from unconsolidated affiliates where the predecessor anticipated receiving dividends and the favorable resolution of certain tax matters related to the first half of 2011.

If we had recorded income taxes effective January 1, 2013, through December 31, 2013, pro forma income from continuing operations would have been approximately $2 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, 2013 (in millions)
Deferred tax liabilities	
Property, plant and equipment	$ 453
Total deferred tax liabilities	453
Deferred tax assets	
Net operating loss and tax credit carryovers	252
Employee benefits	2
Investment in partnership	11
Financial derivatives	3

Legal and other reserves		2
Asset retirement obligations		19
Transaction costs		21
Total deferred tax assets		310
Net deferred tax liabilities	$	143

Unrecognized Tax Benefits. We are not currently subject to any U.S. or state income tax audits. 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, 2013 there were no unrecognized tax benefits as income taxes in our financial statements in continuing operations. Unrecognized tax benefits for the predecessor were transferred to KMI as part of the Acquisition.

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We classify interest and penalties related to unrecognized tax benefits as income taxes in our financial statements. We did not recognize interest and penalties in our consolidated income statements in 2013 or 2012, nor do we have any accrued interest and penalties in our consolidated balance sheet as of December 31, 2013 and December 31, 2012.

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, 2013 (in millions):

	Expiration Period 2031 - 2033
U.S. federal net operating loss	$ 648
[redacted]	
State net operating loss	$ 120

There is a valuation allowance of less than $1 million on the state NOLs that expire in five years and where it is more likely than not those deferred income tax assets will not be realized.

We also have U.S. federal alternative minimum tax credits of $9 million that carry over indefinitely. We have capital loss carryovers of $23 million. Use of our federal carryover is subject to the limitations provided under Sections 382 of the Internal Revenue Code. Such limitation would not cause any net operating losses 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, 2013, the valuation allowance recorded on state net operating losses for our continuing operations was less than $1 million. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances.

5. Earnings Per Share

On January 2, 2014, we completed a 62.553-for-1 stock split of our common stock. For the statements of income of the successor, 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. For the financial statement periods presented, there were no dilutive securities for purposes of calculating diluted earnings per share.

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.

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6. Financial Instruments

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

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in millions)		
Long-term debt	$ 4,421	$ 4,841	$ 4,695	$ 5,039
Derivative instruments	$ 109	$ 109	$ 165	$ 165

For the years ended December 31, 2013 and 2012, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. We hold long term debt obligations (see Note 8) with various terms. We estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk 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 production through the use of oil and natural gas swaps, basis swaps and option contracts. As of December 31, 2013 and 2012, we had total derivative contracts of 47 MMBbls and 34 MMBbls of oil and 135 TBtu and 276 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, 2014 and February 24, 2014.

	2014 Volumes	2015 Volumes(1)	2016 Volumes(1)
Oil (MBbls)			
Fixed Price Swaps			
Brent	160	2,555	4,026
LLS(1)			2,562
Basis Swaps	1,557		183
Natural Gas (TBtu)			
Fixed Price Swaps		4	
NGLs (MMGal)			
Propane Fixed Price Swaps	28		
Propane Collars			
Ceilings	14		
Floors	14		

(1) In January 2014, we unwound 2,555 MBbls of 2015 WTI fixed price swaps in exchange for 2,562 MBbls of 2016 LLS fixed price swaps. No cash or other consideration was included as part of this exchange.

Interest Rate Derivative Instruments. In 2012, we entered into interest rate swaps with a notional amount of $600 million that are intended to reduce variable interest rate risk. These interest rate derivative instruments started in November 2012 and extend through April 2017. As of December 31, 2013 and 2012, we had a net asset of $4 million and a net liability of $2 million, respectively, related to interest rate derivative instruments listed in our consolidated balance sheet. For the year ended December 31, 2013 and the period from February 14 to December 31, 2012 we recorded income of $3 million and expense of $3 million, respectively, in interest expense 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:

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- 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, 2013 and 2012, all 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.

Financial Statement Presentation. The following table presents the fair value associated with derivative financial instruments as of December 31, 2013 and 2012. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

	Level 2							
	Derivative Assets				Derivative Liabilities			
	Gross(1) Fair Value	Impact of Netting	Balance Sheet Location: Current	Balance Sheet Location: Non-current	Gross(1) Fair Value	Impact of Netting	Balance Sheet Location: Current	Balance Sheet Location: Non-current
	(in millions)				(in millions)			
December 31, 2013								
Derivatives	$ 164	$ (20)	$ 47	$ 97	$ (55)	$ 20	$ (35)	$
December 31, 2012								
Derivatives	$ 235	$ (39)	$ 108	$ 88	$ (70)	$ 39	$ (17)	$ (14)

(1) Gross derivative assets are comprised primarily of $157 million and $231 million of oil and natural gas derivatives and $7 million and $4 million of interest rate derivatives as of December 31, 2013 and December 31, 2012, respectively. Gross derivative liabilities are comprised primarily of $52 million and $64 million of oil and natural gas derivatives and $3 million and $6 million of interest rate derivatives as of December 31, 2013 and December 31, 2012, 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, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011
(Losses) gains on financial derivative instruments	$ (52)	$ (62)	$ 365	$ 284
Accumulated other comprehensive income			5	11

Credit Risk. We are subject to the risk of loss on our financial 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, 2013 represent derivative 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 $2.5 billion RBL credit facility. Subject to the terms of our $2.5 billion RBL credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the RBL Facility.

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7. Property, Plant and Equipment

Unproved Oil and Natural Gas Properties (Successor). As December 31, 2013 and December 31, 2012, we had $1.4 billion and $2.3 billion of unproved oil and natural gas properties on our balance sheet. During 2013, we transferred approximately $0.8 billion from unproved properties to proved properties. During 2013 and the successor period of 2012, we recorded $36 million and $23 million of amortization of unproved leasehold costs in exploration expense in our income statement. Suspended well costs were not material as of December 31, 2013 or December 31, 2012.

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 of 7 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 that liability for the periods ended December 31 were as follows:

	Year ended December 31, 2013	February 14 to December 31, 2012
	(in millions)	
Net asset retirement liability at beginning of period	$ 44	$
Fair value of asset retirement liability at Acquisition date		102
Liabilities settled	(2)	(2)
Property sale(1)	(1)	(64)
Accretion expense	4	3
Liabilities incurred	7	5
Changes in estimate	1	
Net asset retirement liability at December 31(2)	$ 53	$ 44

(1) From February 14 to December 31, 2012, property sales relate to the sale of properties in the Gulf of Mexico.

(2) Amounts do not include $37 million and $36 million as of December 31, 2013 and 2012, respectively, of net asset retirement liability associated with our Brazil operations classified as discontinued operations.

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, 2013 was $19 million. For the period from February 14 to December 31, 2012 capitalized interest was $12 million, and for the predecessor periods from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011, it was $4 million and $13 million, respectively.

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8. Long Term Debt

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

EP Energy LLC					
$2.5 billion RBL credit facility - due May 24, 2017	Variable	$	295	$	105
$750 million senior secured term loan - due May 24, 2018(1)(3)	Variable		495		742
$400 million senior secured term loan - due April 30, 2019(2)(3)	Variable		149		399
$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		349
Total		$	4,421	$	4,695

(1) The Term Loan was issued at 99 percent of par and carries interest at a specified margin over the LIBOR of 4.00%, with a minimum LIBOR floor of 1.00%. As of December 31, 2013 the effective interest rate of the note was 3.50%. In May 2013, we entered into an agreement to reprice our term loan which will carry interest at a specified margin over the LIBOR of 2.75%, with a minimum LIBOR floor of 0.75% over the remaining life of the term loan.

(2) The Term Loan carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%.

(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, 2013 and 2012 we have $116 million and $140 million, respectively, in deferred financing costs on our consolidated balance sheets. During 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, $13 million, and $7 million, respectively, of deferred financing costs. These costs are included in interest expense. During 2013, we recorded a $9 million loss on the extinguishment of debt in our consolidated income statement reflecting 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. During the successor period of 2012, we recorded a $14 million loss on debt extinguishment in our consolidated income statement reflecting 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.

In 2014, we repaid and retired our senior PIK toggle note and a portion of RBL borrowings with proceeds from our initial public offering. We also recorded an approximate $15 million loss on extinguishment of debt as a result of the retirement of the PIK toggle note.

$2.5 Billion Reserve-based Loan (RBL). We have a $2.5 billion credit facility in place which allows us to borrow funds or issue letters of credit (LCs). As of December 31, 2013, we had $295 million of outstanding borrowings and approximately $8 million of letters of credit issued under the facility, leaving $2.2 billion of remaining capacity available. As of February 24, 2014, we had $275 million in outstanding borrowings under the facility. Listed below is a further description of our credit facility as of December 31, 2013:

Credit Facility	Maturity Date	Interest Rate	Commitment fees
$2.5 billion RBL	May 24, 2017	LIBOR + 1.50%(1) 1.50% for LCs	0.375% commitment fee on unused capacity

(1) Based on our December 31, 2013 borrowing level. Amounts outstanding under the $2.5 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. Our next redetermination date is in April 2014. 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

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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.

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 4.75 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, 2013, we were in compliance with our debt covenants.

9. Commitments and Contingencies

Legal Matters

We and our subsidiaries and affiliates are parties to various legal actions and claims that arise in the ordinary course of our business. For each 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, 2013, we had approximately $1 million accrued for all outstanding legal matters.

Southeast Louisiana Flood Protection Authority v. EP Energy Management, L.L.C. The levee authority for New Orleans and surrounds have 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. 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. The validity of the causes of action as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable.

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, plugging and abandonment obligations for assets no longer owned or operated by us. As of December 31, 2013, we had approximately $5 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, 2013, we had accrued less than $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, at this time we do not expect a material impact to our existing operations. 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. Although such rules and proposals will generally favor the use of natural gas over other fossil fuels such as coal, it remains uncertain what regulations will ultimately be adopted and when they will be adopted. In addition, 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 in August 2013. We do not anticipate material capital expenditures to meet these requirements.

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 January 14, 2014, EPA proposed extending this deadline twelve to eighteen months, during which time EPA anticipates separate rulemaking to create general permits for true minor sources in the oil and gas production industry. Comments to EPA s proposed extension are due March 17, 2014. Until such regulations are adopted, it is uncertain what impact they might have on our operations in tribal lands.

In the State of Utah we are currently obtaining or amending air quality permits for a number of small oil and natural gas production facilities. As part of this permitting process, we incurred capital expenditures of less than $1 million during 2013 and anticipate that we will incur less than $1 million in 2014 related to the installation of storage tank emission controls at our existing facilities.

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 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, 2013, 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 from 2012 through 2018. Future minimum annual rental commitments under non-cancelable future operating lease commitments at December 31, 2013, were as follows:

Year Ending December 31,		**Operating Leases (in millions)**
2014	$	12
2015		11
2016		11
2017		8
2018		
Total	$	42

Rental expense for the successor periods for the year ended December 31, 2013 and for the period from February 14 to December 31, 2012 was $13 million and $10 million, respectively. Rental expense for the predecessor periods from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011 was $1 million and $2 million, respectively.

Other Commercial Commitments

At December 31, 2013, we have various commercial commitments totaling $894 million primarily related to commitments and contracts associated with volume and transportation, drilling rigs, completion activities, seismic activities and management fees. Our annual obligations under these arrangements are $143 million in 2014, $95 million in 2015, $100 million in 2016, $100 million in 2017, $102 million in 2018, and $354 million thereafter. Our affiliates were party to a management fee agreement requiring an annual management fee of $25 million paid to our Sponsors. Commencing on January 1, 2014, the agreement was amended whereby the management fee is payable in non-refundable quarterly installments of $6.25 million at the beginning of each quarter and was paid on January 1, 2014. Also in January, the amended agreement was terminated.

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

Long Term Incentive Compensation Programs. Upon the closing of the Acquisition, we adopted new long term incentive (LTI) programs, including an annual performance-based cash incentive payment program and certain long-term equity based programs. Each of these awards is further discussed below:

- *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 year ended December 31, 2013 and for the period from February 14 to December 31, 2012, we recorded approximately $16 million and $8 million, respectively, in expense related to these awards. As of December 31, 2013, we had unrecognized compensation expense of $12 million related to these awards of which approximately $9 million will be recognized in 2014 and the remainder on an accelerated basis over the remaining requisite service period.

• *Long Term Equity Incentive Awards.* We have provided certain individuals with long term equity incentive awards as follows:

• *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 (i) matching Class A unit grants in an amount 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 which was treated as a liability award and was paid in March 2013 equivalent to the amount of the matching Class A unit grant. For accounting purposes, we treated the matching Class A unit grants as compensatory equity awards. These awards had a combined fair value of approximately $24 million on the grant date. For the guaranteed cash bonus, we recognized the fair value as compensation cost over the

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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 year ended December 31, 2013 and the period from February 14 to December 31, 2012, we recognized approximately $6 million and $11 million, respectively, as compensation expense related to both of these awards. As of December 31, 2013, we had unrecognized compensation expense of $7 million related to the matching Class A unit grants, of which we will recognize $3 million in 2014 and the remainder ratably thereafter as noted above.

- *Management Incentive Units*. In addition to the Class A matching awards described above, certain employees were awarded Management Incentive Units (MIPs). 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, including, without limitation, the occurrence of certain specified capital transactions. 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 profits interests 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 management incentive units assuming a 0.77 % risk free rate, a 5 year time to expiration, and a 73 percent volatility rate. Based on these factors, we determined a grant date fair value of $74 million. For the year ended December 31, 2013 and the period from February 14 to December 31, 2012, we recognized approximately $19 million and $15 million, respectively, as compensation expense related to these awards. As of December 31, 2013, we had unrecognized compensation expense of $40 million. Of this amount, $21 million of the unrecognized compensation expense, net of forfeitures, will continue to be recognized on an accelerated basis for each tranche of the award, over the remainder of the five year requisite service period. The remaining $19 million will be recognized upon a specified capital transaction when the right to such amounts become nonforfeitable.

- *Other*. On September 18, 2013, we issued additional 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 Sponsors 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 2013 and for the period subsequent to the Acquisition in 2012, we had contributed $12 million and $7 million, respectively, of matching and non-elective employer contributions.

11. 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. As of December 31, 2012, our investment in Four Star was $220 million (including approximately $125 million related to the excess of the carrying value of our investment in Four Star relative to the underlying equity in its net assets). Our income statement 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 (in millions).

	Successor		Predecessor	
	Year Ended December 31, 2013	February 14 to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011
		(in millions)		
Operating revenues	$ 142	$ 105	$ 75	$ 257
Operating expenses	94	87	58	167
Net income	30	11	11	60

	December 31, 2012 (in millions)
Financial position data:	
Current assets	$ 64
Non-current assets	241
Current liabilities	51
Non-current liabilities	133
Equity in net assets	121

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 and for the year ended December 31, 2011 was $12 million and $34 million, respectively.

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 and for the year ended December 31, 2011 were $8 million and $46 million, respectively.

12. Related Party Transactions

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

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 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. We entered into a management fee agreement with certain of our Sponsors to provide certain management consulting and advisory services which terminates on the twelve-year anniversary of the Acquisition (May 24, 2012), if not terminated earlier by mutual agreement of the parties, or upon a change in control or specified initial public offering transaction. Under the fee agreement, we paid a non-refundable annual management fee of $25 million at the beginning of each year. For the year ended December 31, 2013 we recognized approximately $26 million in general and administrative expense related to the management fee and other fees. Commencing in 2014, the management fee became payable in quarterly installments at the beginning of each calendar quarter, and on January 1, 2014, we paid $6.25 million for services to be rendered in that quarter. On December 20, 2013, the Management Fee Agreement was amended and restated in its entirety pursuant to which an additional fee became payable to our Sponsors in respect of management and similar services rendered prior to our initial public offering. 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 (the lesser of (i) 1% of the aggregate enterprise value paid or provided by the Company Group and (ii) $100,000,000) which will be recorded in general and administrative expense in that period. 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. In November 2012, we entered into a supply agreement with an Apollo affiliate through October 2014 to provide certain fracturing materials for our Eagle Ford drilling operations. As of December 31, 2013, we recorded approximately $120 million as capital expenditures for amounts provided under this agreement.

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.

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 percent 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 periods (in millions):

	Predecessor	
	January 1 to May 24, 2012	Year ended December 31, 2011
Operating revenues	$ 143	$ 634
Operating expenses	44	138
Reimbursements of operating expenses		3

• *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 4 for additional information on income tax related matters.

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- *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).

	Successor			
2013	**March 31**	**June 30**	**September 30**	**December 31**
Operating revenues				
Physical sales	$ 363	$ 408	$ 471	$ 450
Financial derivatives	(131)	166	(142)	55
Operating (loss) income	(49)	272	(2)	159
Income tax expense			30	33
(Loss) income from continuing operations	(140)	189	(148)	41
Net (loss) income	(114)	201	310	53

	Predecessor		Successor		
	Quarters Ended				
		June 30			
2012	**March 31**	**April 1 to May 24**	**April 1 to June 30**	**September 30**	**December 31**
Operating revenues					
Physical sales	$ 375	$ 192	$ 108	$ 326	$ 355
Financial derivatives	76	289	57	(181)	62
Operating income (loss)	56	282	(104)	(105)	143
Income tax expense	38	96			
Income (loss) from continuing operations	11	176	(158)	(205)	63
Net income (loss)	15	163	(150)	(196)	90

Below are additional significant items affecting comparability of amounts reported in the respective periods of 2013 and 2012:

June 30, 2012. For the successor period from April 1 to June 30 we recorded $173 million of transaction costs related to the Acquisition.

March 31, 2012. We recorded a $62 million non-cash charge related to the unevaluated costs in Egypt based on a decision to exit activities in that area.

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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 have operations in Brazil that are currently under contract to be sold.

All periods included for capitalized costs, total costs incurred and results in operations present our Brazil operations as discontinued operations. The successor periods (periods after May 25, 2012) also present domestic natural gas assets sold, including the CBM, South Texas and the majority of our 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. In addition, we sold our approximate 49 percent equity investment in Four Star in September 2013.

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

	U.S.
2013 Consolidated:	
Oil and natural gas properties	$ 8,370
Less accumulated depreciation, depletion and amortization	840
Net capitalized costs	$ 7,530
2012 Consolidated:	
Oil and natural gas properties	$ 6,513
Less accumulated depreciation, depletion and amortization	203
Net capitalized costs	$ 6,310
2012 Unconsolidated Affiliate Four Star(1):	
Oil and natural gas properties	$ 627
Less accumulated depreciation, depletion and amortization	510
Net capitalized costs	$ 117

(1) Amounts represent our approximate 49 percent equity interest in the underlying oil and gas assets of Four Star. We sold our interest in Four Star in September 2013.

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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 year ended December 31, 2013 and the period from February 14, 2012 to December 31, 2012 and the predecessor periods from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011 (in millions):

	U.S.	Egypt(1)	Worldwide
Successor			
2013 Consolidated:			
Property acquisition costs			
Proved properties	$ 2	$	$ 2
Unproved properties	20		20
Exploration costs (capitalized and expensed)	95		95
Development costs	1,783		1,783
Costs expended	1,900		1,900
Asset retirement obligation costs	7		7
Total costs incurred	$ 1,907	$	$ 1,907
Consolidated from February 14, 2012 to December 31, 2012:			
Property acquisition costs			
Proved properties	$	$	$
Unproved properties	19		19
Exploration costs (capitalized and expensed)	107		107
Development costs	792		792
Costs expended	918		918
Asset retirement obligation costs	10		10
Total costs incurred	$ 928	$	$ 928
Unconsolidated Affiliate from February 14, 2012 to December 31, 2012:			
Development costs expended	$ 2	$	$ 2
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	$ 3	$	$ 3
2011 Consolidated:			
Property acquisition costs			
Proved properties	$	$	$
Unproved properties	45		45
Exploration costs	873	8	881
Development costs	685		685
Costs expended	1,603	8	1,611
Asset retirement obligation costs	25		25
Total costs incurred	$ 1,628	$ 8	$ 1,636

2011 Unconsolidated Affiliate:			
Development costs expended	$ 12	$	$ 12

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

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

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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 $37 million and $25 million for the year ended December 31, 2013 and for the period from February 14, 2012 to December 31, 2012, and capitalized interest of $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 and $81 million for the year ended December 31, 2011. The predecessor also capitalized interest of $4 million and $13 million for the period from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011.

Oil and Natural Gas Reserves. Net quantities of proved developed and undeveloped reserves of natural gas, oil and condensate and NGLs and changes in these reserves at December 31, 2013 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 2013 consolidated proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2013 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, 2013. In connection with its audit, Ryder Scott reviewed 94% (by volume) of our total proved reserves (or 96% not including proved reserves associated with our Brazil assets classified as discontinued operations) on a barrel of oil equivalent basis, representing 96% of the total discounted future net cash flows of these proved reserves. For the audited properties, 98% of our total proved undeveloped (PUD) reserves were evaluated. As of December 31, 2013, we did not have PUD reserves associated with our Brazil assets. Ryder Scott concluded the overall procedures and methodologies that we utilized in preparing our estimates of proved reserves as of December 31, 2013 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 (SPE) 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, 2013							
	U.S.				Brazil			Total
	Natural Gas (in Bcf)	Oil and Condensate (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)	Natural Gas (in Bcf)	Oil and Condensate (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	84	599	235	14.7		5		14.7
Revisions other than prices	129	(36,322)	20,458	5.6		(17)		5.6
Extensions and discoveries(1)	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	1,071	293,424	75,673	547.5	59	1,835	11.6	559.1
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	84,034	17,715	182.4	59	1,835	11.6	194.0
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	84,034	17,715	182.4	59	1,835	11.6	194.0
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) 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.

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	Year Ended December 31, 2012							
	U.S.				Brazil			Total
	Natural Gas (in Bcf)	Oil and Condensate (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)	Natural Gas (in Bcf)	Oil and Condensate (in MBbls)	Equivalent Volumes (in MMBoe)	Total 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(1)	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(1)	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

(1) 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.

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	Year Ended December 31, 2011							
	U.S.				Brazil			Total
	Natural Gas (in Bcf)	Oil and Condensate (in MBbls)	NGLs (in MBbls)	Equivalent Volumes (in MMBoe)	Natural Gas (in Bcf)	Oil and Condensate (in MBbls)	Equivalent Volumes (in MMBoe)	Equivalent Volumes (in MMBoe)
Consolidated								
Proved developed and undeveloped reserves								
Beginning of year	2,396	103,240	9,051	511.5	85	2,654	16.8	528.3
Revisions due to prices	(9)	713		(0.8)		3		(0.8)
Revisions other than prices	44	(1,630)	(1,124)	4.6	6	(34)	1.1	5.7
Extensions and discoveries(1)	519	90,128	7,525	184.1				184.1
Purchases of reserves in place		13						
Sales of reserves in place	(153)	(8,983)	(139)	(34.5)				(34.5)
Production	(231)	(5,680)	(1,068)	(45.2)	(10)	(354)	(2.1)	(47.3)
End of year	2,566	177,801	14,245	619.7	81	2,269	15.8	635.5
Proved developed reserves:								
Beginning of year	1,559	38,278	6,096	304.2	75	2,403	14.9	319.1
End of year	1,488	46,797	5,168	300.0	81	2,269	15.8	315.8
Proved undeveloped reserves:								
Beginning of year	837	64,962	2,955	207.3	10	251	1.9	209.2
End of year	1,078	131,004	9,077	319.7				319.7
Unconsolidated Affiliate Four Star								
Proved developed and undeveloped reserves								
Beginning of year	155	1,623	4,458	31.9				31.9
Revisions due to prices	(5)	31	(28)	(0.9)				(0.9)
Revisions other than prices	2	221	1,034	1.6				1.6
Production	(17)	(306)	(556)	(3.6)				(3.6)
End of year	135	1,569	4,908	29.0				29.0
Proved developed reserves:								
Beginning of year	129	1,574	3,483	26.6				26.6
End of year	116	1,519	4,066	24.9				24.9
Proved undeveloped reserves:								
Beginning of year	26	49	975	5.4				5.4
End of year	19	49	842	4.0				4.0
Total Combined								
Proved developed reserves:								
Beginning of year	1,688	39,852	9,579	330.8	75	2,403	14.9	345.7
End of year	1,604	48,316	9,234	324.9	81	2,269	15.8	340.7
Proved undeveloped reserves:								
Beginning of year	863	65,011	3,930	212.7	10	251	1.9	214.6
End of year	1,097	131,053	9,919	323.7				323.7

(1) Of the 184.1 MMBoe of extensions and discoveries, 64.8 MMBoe are in the Haynesville Shale area, 10.8 MMBoe are in the Altamont area, 79.8 MMBoe are in the Eagle Ford Shale and 18.8 MMBoe are in the Wolfcamp Shale. There were no extensions or discoveries in Brazil.

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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 U.S. price used to estimate our proved reserves at December 31, 2013 was $96.94 per barrel of oil (WTI) and $3.67 per MMBtu for natural gas (Henry Hub). The prices used for our International assets were contractually defined. The aggregate International price used to estimate our proved reserves at December 31, 2013 was $108.02 per barrel of oil and $6.31 per MMBtu for natural gas.

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 may justify revision of that estimate.

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, 2013, 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, 2013.

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Results of Operations. Results of operations for oil and natural gas producing activities for the successor periods for the year ended December 31, 2013 and from February 14, 2012 to December 31, 2012 and the predecessor periods from January 1, 2012 to May 24, 2012 and year ended December 31, 2011 (in millions):

	U.S.	Egypt	Worldwide
Successor			
2013 Consolidated:			
Net Revenues(1) Sales to external customers	$ 1,692	$	$ 1,692
Costs of products and services	(159)		(159)
Production costs(2)	(254)		(254)
Depreciation, depletion and amortization(3)	(605)		(605)
Exploration expense	(45)		(45)
Income tax expense	(226)		(226)
Results of operations from producing activities	$ 403	$	$ 403
2013 Unconsolidated Affiliate Four Star(4)*:*			
Net Revenues Sales to external customers	$ 69	$	$ 69
Costs of products and services	(6)		(6)
Production costs(2)	(19)		(19)
Depreciation, depletion and amortization(5)	(18)		(18)
	26		26
Income tax expense	(8)		(8)
Results of operations from producing activities	$ 18	$	$ 18
Consolidated from February 14, 2012 to December 31, 2012:			
Net Revenues(1) Sales to external customers	$ 789	$	$ 789
Costs of products and services	(85)		(85)
Production costs(2)	(111)		(111)
Depreciation, depletion and amortization(3)	(202)		(202)
Exploration expense	(43)		(43)
Results of operations from producing activities	$ 348	$	$ 348
Unconsolidated Affiliate Four Star from February 14, 2012 to December 31, 2012(4)*:*			
Net Revenues Sales to external customers	$ 52	$	$ 52
Costs of products and services	(3)		(3)
Production costs(2)	(24)		(24)
Depreciation, depletion and amortization(5)	(16)		(16)
	9		9
Income tax expense	(3)		(3)
Results of operations from producing activities	$ 6	$	$ 6
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(5)	(11)		(11)
	8		8
Income tax expense	(3)		(3)
Results of operations from producing activities	$ 5	$	$ 5
2011 Consolidated:			
Net Revenues(1)			
Sales to external customers	$ 837	$	$ 837
Affiliated sales	634		634
Total	1,471		1,471
Costs of products and services	(91)		(91)
Production costs(2)	(245)		(245)
Depreciation, depletion and amortization(3)	(563)		(563)
	572		572
Income tax expense	(207)		(207)
Results of operations from producing activities	$ 365	$	$ 365
2011 Unconsolidated Affiliate Four Star(4):			
Net Revenues Sales to external customers	$ 123	$	$ 123
Costs of products and services	(4)		(4)
Production costs(2)	(49)		(49)
Depreciation, depletion and amortization(5)	(27)		(27)
	43		43
Income tax expense	(15)		(15)
Results of operations from producing activities	$ 28	$	$ 28

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(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 $4 million and $9 million for the year ended December 31, 2013 and the period from February 14, 2012 to December 31, 2012, $5 million and $13 million for the predecessor periods from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011, 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 and $34 million for the predecessor periods from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011 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) Includes accretion expense on asset retirement obligations of $1 million for the period from February 14, 2012 to December 31, 2012 and $1 million and $2 million for the predecessor periods from January 1, 2012 to May 24, 2012 and the year ended December 31, 2011, 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.	Brazil	Worldwide
2013 Consolidated:			
Future cash inflows(1)	$ 33,719	$ 615	$ 34,334
Future production costs	(9,187)	(365)	(9,552)
Future development costs	(6,789)	(71)	(6,860)
Future income tax expenses	(6,087)	(18)	(6,105)
Future net cash flows	11,656	161	11,817
10% annual discount for estimated timing of cash flows	(5,806)	(32)	(5,838)
Standardized measure of discounted future net cash flows	$ 5,850	$ 129	$ 5,979
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(2)		(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(3):			
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
2011 Consolidated:			
Future cash inflows(1)	$ 26,079	$ 768	$ 26,847
Future production costs	(5,840)	(415)	(6,255)
Future development costs	(6,343)	(34)	(6,377)
Future income tax expenses	(4,086)	(23)	(4,109)
Future net cash flows	9,810	296	10,106
10% annual discount for estimated timing of cash flows	(4,793)	(97)	(4,890)
Standardized measure of discounted future net cash flows	$ 5,017	$ 199	$ 5,216
2011 Unconsolidated Affiliate Four Star(3):			
Future cash inflows(1)	$ 938	$	$ 938
Future production costs	(348)		(348)
Future development costs	(66)		(66)
Future income tax expenses	(201)		(201)
Future net cash flows	323		323
10% annual discount for estimated timing of cash flows	(129)		(129)
Standardized measure of discounted future net cash flows	$ 194	$	$ 194

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2013, 2012 and 2011. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

(2) 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.

(3) Amounts represent our approximate 49 percent 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)		
	2013	2012	2011
Consolidated:			
Sales and transfers of oil and natural gas produced net of production costs	$ (1,493)	$ (1,433)	$ (1,200)
Net changes in prices and production costs	(417)	(871)	1,057
Extensions, discoveries and improved recovery, less related costs	2,801	2,539	2,140
Changes in estimated future development costs	(10)	978	(415)
Previously estimated development costs incurred during the period	679	587	601
Revision of previous quantity estimates	473	(1,863)	49
Accretion of discount	796	731	430
Net change in income taxes	(3,083)	1,683	(599)
Sales of reserves in place	(909)	(296)	(587)
Change in production rates, timing and other	81	(210)	(261)
Net change	$ (1,082)	$ 1,845	$ 1,215
Unconsolidated Affiliate Four Star:			
Sales and transfers of oil and natural gas produced net of production costs	$ (41)	$ (48)	$ (74)
Net changes in prices and production costs	6	(112)	62
Extensions, discoveries and improved recovery, less related costs		25	
Changes in estimated future development costs	25	5	(14)
Revision of previous quantity estimates	10	19	6
Accretion of discount	18	22	22
Net change in income taxes	68	39	(9)
Sales of reserves in place	(260)		
Change in production rates, timing and other	38	(8)	19
Net change	(136)	$ (58)	$ 12
Representative NYMEX prices:(2)			
Oil (Bbl)	$ 96.94	$ 94.61	$ 96.19
Natural gas (MMBtu)	$ 3.67	$ 2.76	$ 4.12
Aggregate International prices:(2)			
Oil (Bbl)	$ 108.02	$ 111.21	$ 109.29
Natural gas (MMBtu)	$ 6.31	$ 6.55	$ 5.31

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

(2) 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, 2013, 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, 2013. 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 2013 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*

Board of Directors and Executive Officers

The following table provides information regarding our current executive officers and members of our Board of Directors (the Board), including the experience, qualifications, attributes or skills of such board members (with ages as of February 15, 2014). Our directors were nominated and appointed by the Sponsors pursuant to the terms of the Stockholders Agreement. See Certain Relationships and Related Transactions, and Director Independence for further details regarding the rights of the Sponsors to elect our directors.

Name	Age	Position
Brent J. Smolik	52	President, Chief Executive Officer and Chairman of the Board
Clayton A. Carrell	48	Executive Vice President and Chief Operating Officer
Joan M. Gallagher	50	Senior Vice President, Human Resources and Administrative Services
John D. Jensen	44	Executive Vice President, Operations Services
Dane E. Whitehead	52	Executive Vice President and Chief Financial Officer
Marguerite N. Woung-Chapman	48	Senior Vice President, General Counsel and Corporate Secretary
Ralph Alexander	58	Director
Gregory A. Beard	42	Director
Wilson B. Handler	29	Director
John J. Hannan	61	Director
Michael S. Helfer	68	Director
Sam Oh	43	Director
Ilrae Park	47	Director
Robert M. Tichio	36	Director
Donald A. Wagner	50	Director
Rakesh Wilson	38	Director

Brent J. Smolik. Mr. Smolik has been our President, Chief Executive Officer and Chairman of the Board since August 30, 2013, President and Chief Executive Officer of EP Energy LLC since May 2012 and previously served as Chairman of the Board of Managers of EPE Acquisition, LLC from May 2012 to August 2013. He was previously Executive Vice President and a member of the Executive Committee of El Paso Corporation and President of our predecessor, EP Energy Corporation (a/k/a/ El Paso Exploration & Production Company), since November 2006. 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 boards of the American Exploration and Production Council and America s Natural Gas Alliance. 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. With over 29 years of energy industry experience, Mr. Smolik brings a comprehensive knowledge and understanding of our business to the Board and provides the Board with essential insight and guidance from an inside perspective on the day-to-day operations of our company.

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), since June 2010. 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 since March 2011. From August 2005 until February 2011, she served as Vice President, Human Resources of our predecessor, 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

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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.

John D. Jensen. Mr. Jensen has been our Executive Vice President, Operations Services, since August 30, 2013 and Executive Vice President, Operations Services, of EP Energy LLC since May 2012. He was previously Senior Vice President, Operations of our predecessor, EP Energy Corporation (a/k/a/ El Paso Exploration & Production Company), since June 2010, and was Vice President of Operations from May 2009 until May 2010. Mr. Jensen previously served as Vice President, Strategy and Engineering from April 2007 to May 2009. Prior to joining El Paso, Mr. Jensen served as Vice President, Business Development and Strategic Planning for ConocoPhillips Canada from June 2005 to March 2007. In addition, he held various positions in upstream and midstream engineering, planning, and business development at ConocoPhillips starting in July 1990. He is a board member of the Texas Oil and Gas Association, the Independent Petroleum Association of America, and Junior Achievement of Southeast Texas. Mr. Jensen is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

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 since October 2009. He previously served as Senior Vice President and Chief Financial Officer of our predecessor, 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 since November 2009. 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. Ms. Woung-Chapman is also on the Board of Directors for the Girl Scouts of San Jacinto Council.

Ralph Alexander. Mr. Alexander has been a director of our Board since September 3, 2013. Mr. Alexander is a Managing Director of Riverstone Holdings LLC and joined Riverstone in September 2007. During 2007, Mr. Alexander served as a consultant to TPG Capital. For nearly 25 years, Mr. Alexander served in various positions with subsidiaries and affiliates of BP plc, one of the world s largest energy firms. From June 2004 until December 2005, he served as Chief Executive Officer of Innovene, BP s $20bn olefins and derivatives subsidiary. From 2001 until June 2004, he served as Chief Executive Officer of BP s Gas, Power and Renewables and Solar segment and was a member of the BP group executive committee. Prior to that, Mr. Alexander served as a Group Vice President in BP s Exploration and Production segment and BP s Refinery and Marketing segment. He held responsibilities for various regions of the world, including North America, Russia, the Caspian, Africa and Latin America. Prior to these positions, Mr. Alexander held various positions in the upstream, downstream and finance groups of BP. In addition to serving on the boards of a number of Riverstone portfolio companies and their affiliates, Mr. Alexander is a director of Stein Mart Corporation since May 2007. He previously served on the board of KiOR Inc., Amyris, Inc., Foster Wheeler AG and Anglo American plc. He holds a BS and MS in nuclear engineering from Brooklyn Polytech (now NYU Polytechnic) and holds an MS in management science from Stanford University. He is currently Chairman of the Board of NYU Polytechnic and is a New York University Trustee. Mr. Alexander was appointed to our Board by Riverstone. We believe Mr. Alexander s extensive experience with the energy industry enables him to provide important insight and guidance to our management team and Board of Directors.

Gregory A. Beard. Mr. Beard has been a director of our Board since August 30, 2013 and previously served as a member of the Board of Managers of EPE Acquisition, LLC from May 2012 to August 2013. Mr. Beard joined Apollo in June 2010 as the Global Head of Natural Resources, based in the New York office. Mr. Beard joined Apollo with 19 years of investment experience, the last ten of which were with Riverstone Holdings where he was a founding member, Managing Director and lead deal partner in many of the firm s top oil and gas and energy service investments. While at Riverstone, Mr. Beard was involved in all aspects of the investment process including sourcing, structuring, monitoring and exiting transactions. Mr. Beard began his career as a Financial Analyst at Goldman Sachs, where he played an active role in that firm s energy-sector principal investment activities. Mr. Beard has served on the board of directors of many oil and natural gas companies including, Belden & Blake Corporation, Canera Resources, Cobalt International Energy, Eagle Energy, Legend Natural Gas I IV, Mariner Energy, Phoenix Exploration, Titan Operating,

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Vantage Energy and Virginia Uranium. Mr. Beard has also served on the board of directors of various oilfield services companies, including CDM Max, CDM Resource Management, and International Logging. Mr. Beard currently serves on the board of directors of Apex Energy, LLC, Athlon Energy Inc., Double Eagle Energy Holdings, LLC, NRI Management Group, LLC, Pinnacle Agriculture Holdings, LLC, and Talos Energy, LLC. Mr. Beard received his BA from the University of Illinois at Urbana. Mr. Beard was appointed to our Board by the Apollo Funds. Based upon Mr. Beard s extensive investment and management experience, particularly in the energy sector, his strong financial background and his service on the boards of multiple oil and natural gas exploration and production companies and oilfield services companies, which have provided him with a deep working knowledge of our operating environment, we believe that he possesses the requisite skills to serve as a member of our Board.

Wilson B. Handler. Mr. Handler has been a director of our Board since November 22, 2013. Mr. Handler joined Apollo in 2011 and is a member of the Natural Resources group. Prior to joining Apollo, Mr. Handler was an investment professional at First Reserve, where he was involved in the execution and monitoring of investments in the energy sector. Previously, he worked in the Investment Banking Division at Lehman Brothers in the Natural Resources group. Currently, Mr. Handler serves on the board of directors of Athlon Energy Inc. Mr. Handler graduated from Dartmouth College with an AB in Economics and Government. Mr. Handler was appointed to our Board by the Apollo Funds. Based upon Mr. Handler s extensive investment experience, his knowledge of the Company and experience in the energy industry, we believe he possesses the requisite skills to serve as a member of our Board.

John J. Hannan. Mr. Hannan has been a director of our Board since December 19, 2013. Mr. Hannan is Chairman of the Board of Directors of Apollo Investment Corporation, a public investment company. He served as Chief Executive Officer of Apollo Investment Corporation from 2006 to 2008. Mr. Hannan, a senior partner of Apollo Management, L.P., co-founded Apollo Management, L.P. in 1990. Mr. Hannan is an advisor to Apollo s Natural Resources group. He has been on several public boards including Vail Resorts, Inc. and Goodman Global, Inc., and is currently on the board of Environmental Solutions Worldwide. Mr. Hannan is actively involved in charitable organizations. He received a BBA from Adelphi University and an MBA from the Harvard Business School. Mr. Hannan was appointed to our Board by the Apollo Funds. Based on Mr. Hannan s strong investment and management experience and his service on multiple boards of directors, we believe that Mr. Hannan possesses the requisite set of skills to serve as a member of our Board.

Michael S. Helfer. Mr. Helfer has been a director of our Board since January 16, 2014. Mr. Helfer has been Vice Chairman of Citigroup Inc. since June 2012 and is responsible for development and execution of Citigroup s domestic and international regulatory strategy, including its response to significant policy and regulatory proposals, including those with cross-border effects. Mr. Helfer expects to retire from Citigroup Inc. in March 2014. From February 2003 until May 2012, he served as General Counsel and Corporate Secretary of Citigroup. From 2000 until 2003, Mr. Helfer served as President, Strategic Investments and Chief Strategic Officer of Nationwide Insurance Company. He graduated from Claremont Men s College (now Claremont McKenna College) with a BA in Economics, summa cum laude, and graduated from Harvard Law School with a J.D., magna cum laude. Mr. Helfer is a member of the Council on Foreign Relations and the American Law Institute. He has served as Chairman of the New York Clearing House Association, Chairman of the Legal Aid Society of the District of Columbia, as a member of the Board of Directors of Lincoln Center Theater, and as a Trustee of the Wexner Center for the Arts. Based upon Mr. Helfer s extensive management, business and leadership experience, we believe that he possesses the requisite set of skills to serve as a member of our Board.

Sam Oh. Mr. Oh has been a director of our Board since August 30, 2013 and previously served as a member of the Board of Managers of EPE Acquisition, LLC from May 2012 to August 2013. Mr. Oh joined Apollo in 2008 and is one of the original founding members of Apollo s Natural Resources group. Prior to joining Apollo, Mr. Oh was with Morgan Stanley s Commodities Department where he led principal investments for the group. While at Morgan Stanley, Mr. Oh launched a successful oil and gas fund, Helios Energy/Royalty Partners, and sat on the board of several portfolio companies. Mr. Oh has 20 years of experience, including 13 years of principal investing. He also has a broad range of experience in the commodities markets including risk management and structured products. Since joining Apollo, Mr. Oh has been actively involved in E&P investments, including leading the Parallel Petroleum acquisition in 2009. Mr. Oh was formerly Chairman of the Board of Parallel Petroleum and is a director of Athlon Energy Inc. Mr. Oh received a BS from the University of Pennsylvania s Wharton School of Business and an MBA from the Yale School of Management. He is also a Certified Public Accountant and a Chartered Financial Analyst. Mr. Oh was appointed to our Board by the Apollo Funds. Based upon Mr. Oh s strong management experience and extensive background in commodities markets having overseen various complex commodities investments, as well as his experience with the Company and his service on multiple boards of directors, we believe that Mr. Oh possesses the requisite set of skills to serve as a member of our Board.

Ilrae Park. Mr. Park has been a director of our Board since August 30, 2013 and previously served as a member of the Board of Managers of EPE Acquisition, LLC from December 2012 to August 2013. Mr. Park joined KNOC in 1990 and worked in the areas of new ventures, asset management worldwide and field operations, spending most of his career in Korea, Indonesia, United Arab Emirates, Yemen and the United States. He is currently the Representative and Managing Director of the U.S. Business Unit of KNOC under which three subsidiaries are running E&P businesses. At the same time, in the United States he is serving as President and board member for KNOC Eagle Ford Corporation and Executive Vice President and board member for Ankor E&P Holdings Corporation.

Mr. Park received his bachelor degree in Petroleum & Minerals Engineering from Hanyang University, a master degree in Petroleum Engineering from Hanyang University and a PhD ABD in Petroleum Engineering from Hanyang University. Mr. Park was appointed to our Board by KNOC. Based on Mr. Park s engineering background and extensive experience in the energy industry, we believe that Mr. Park possesses the requisite set of skills to serve as a member of our Board.

Robert M. Tichio. Mr. Tichio has been a director of our Board since September 3, 2013. Mr. Tichio is a Managing Director of Riverstone Holdings LLC and joined Riverstone in 2006. Prior to joining Riverstone, Mr. Tichio was in the Principal Investment Area (PIA) of Goldman Sachs which manages the firm s private corporate equity investments. Mr. Tichio began his career at J.P. Morgan in the Mergers & Acquisition group where he concentrated on assignments that included public company combinations, asset sales, takeover defenses and leveraged buyouts. In addition to serving on the boards of a number of Riverstone portfolio companies and their affiliates, Mr. Tichio has served as a member of the board of directors of Midstates Petroleum Company, Inc. since October 2012. Mr. Tichio previously served as a member of the board of directors of Gibson Energy (TSE:GEI) from 2008 to 2013 and is a member of the Board of Visitors of the Nelson A. Rockefeller Center at Dartmouth College. He holds an MBA from Harvard Business School and a bachelor s degree from Dartmouth College. Mr. Tichio was appointed to our Board by Riverstone. We believe Mr. Tichio s extensive energy industry background, particularly his expertise in mergers and acquisitions, brings important experience and skill to our Board of Directors.

Donald A. Wagner. Mr. Wagner has been a director of our Board since August 30, 2013 and previously served as a member of the Board of Managers of EPE Acquisition, LLC from May 2012 to August 2013. Mr. Wagner is a Managing Director of Access Industries, having been with Access since 2010. He is responsible for sourcing and executing new investment opportunities in North America, and he oversees Access current North American investments. From 2000 to 2009, Mr. Wagner was a Senior Managing Director of Ripplewood Holdings L.L.C., responsible for investments in several areas and heading the industry group focused on investments in basic industries. Previously, Mr. Wagner was a Managing Director of Lazard Freres & Co. LLC and had a 15-year career at that firm and its affiliates in New York and London. He is a board member of Access portfolio companies Warner Music Group and Boomerang Tube and was on the board of NYSE-listed RSC Holdings from November 2006 until August 2009. Mr. Wagner graduated summa cum laude with an AB in physics from Harvard College. Mr. Wagner was appointed to our Board by Access. Based upon Mr. Wagner s experience as a director of various companies, including public companies, and over 25 years of experience in investing, banking and private equity, we believe that Mr. Wagner possesses the requisite set of skills to serve as a member of our Board.

Rakesh Wilson. Mr. Wilson has been a director of our Board since August 30, 2013 and previously served as a member of the Board of Managers of EPE Acquisition, LLC from May 2012 to August 2013. Mr. Wilson is a Partner of Apollo and joined Apollo in 2009. Prior to joining Apollo, Mr. Wilson was at Morgan Stanley s Commodities Department in the principal investing group responsible for generating, evaluating and executing investment ideas across the energy sector. Mr. Wilson began his career at Goldman Sachs in equity research and then moved to its investment banking division in New York and Asia. Mr. Wilson currently serves on the boards of directors of Athlon Energy Inc. and Talos Energy, LLC and previously served as a director of Parallel Petroleum. Mr. Wilson graduated from the University of Texas at Austin and received his MBA from INSEAD, Fontainebleau, France. He has also taught business courses at universities in China. Mr. Wilson was appointed to our Board by the Apollo Funds. We believe that Mr. Wilson s extensive international investment and risk management experience, his knowledge of the Company and his service on multiple boards have provided him with a strong understanding of the financial, operational and strategic issues facing public companies in our industry, and that he possesses the requisite set of skills to serve as a member of our Board.

Board Composition

The supervision of our management and the general course of our affairs and business operations is entrusted to our Board. Our Board is currently comprised of 11 directors, with (i) five designated by the Apollo Funds, (ii) two designated by Riverstone, (iii) one designated by Access, (iv) one designated by KNOC, (v) our chief executive officer and (vi) one independent director designated by the Apollo Funds. The

Apollo Funds have the right to designate any director as the Chairman of the Board and our chief executive officer currently serves in that capacity. The Apollo Funds have the right to and will designate one additional independent director within one year of January 16, 2014 (the first day of effectiveness of the Company s registration statement under the Securities Act of 1933 in connection with our initial public offering, the Effective Time) and Riverstone has the right to and will designate an independent director within 90 days of the Effective Time. Upon the designation of such independent directors, our Board will have a total of 13 directors, of which three will be independent of us, the Legacy Stockholders and their affiliates under the rules of the New York Stock Exchange (NYSE). See Certain Relationships and Related Transactions, and Director Independence for further details.

Our Board is divided into three classes. The members of each class serve staggered, three-year terms (other than with respect to the initial terms of the Class I and Class II directors, which will be one and two years, respectively). Upon the expiration of the term of a class of directors, directors in that class will be elected for three-year terms at the annual meeting of stockholders in the year in which their term expires.

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- Ralph Alexander, Wilson B. Handler, John J. Hannan and Michael S. Helfer are Class I directors, whose initial terms will expire at the 2015 annual meeting of stockholders;

- Ilrae Park, Donald A. Wagner, Rakesh Wilson and an independent director to be designated by Riverstone within 90 days of the Effective Time are or will be, as applicable, Class II directors, whose initial terms will expire at the 2016 annual meeting of stockholders; and

- Gregory A. Beard, Sam Oh, Robert M. Tichio, and an independent director to be designated by the Apollo Funds within one year of the Effective Time and Brent J. Smolik are or will be, as applicable, Class III directors, whose initial term will expire at the 2017 annual meeting of stockholders.

Any additional directorships resulting from an increase in the number of directors will be distributed among the three classes so that, as nearly as possible, each class will consist of one-third of our directors. This classification of our Board of Directors may have the effect of delaying or preventing changes in control.

Committees of the Board of Directors

The Stockholders Agreement provides that for so long as each Sponsor has the right to designate a director or an observer to the Board, we will cause any committee of our Board to include in its membership such number of members that are consistent with, and reflects, the right of each Sponsor to designate a director or observer to the Board, except to the extent that such membership would violate applicable securities laws or stock exchange or stock market rules. See Certain Relationships and Related Transactions, and Director Independence for further details.

Audit Committee. Our Audit Committee consists of eight members: Sam Oh (chairperson), Ralph Alexander, Gregory A. Beard, Wilson B. Handler, Michael S. Helfer, Ilrae Park, Donald A. Wagner and Rakesh Wilson. Our Board has determined that Sam Oh qualifies as an audit committee financial expert as such term is defined in Item 407(d)(5) of Regulation S-K and that Michael S. Helfer is independent as independence is defined in Rule 10A-3 of the Exchange Act and under the NYSE listing standards. We are a controlled company under the NYSE listing rules, which means that within 90 days of our listing on the NYSE, we will appoint another independent director to our Audit Committee. After such 90-day period and until one year from the date of the Effective Time, we will be required to have a majority of independent directors on our audit committee. Thereafter, we will be required to have an audit committee comprised entirely of independent directors. The Company believes that relying on the controlled company exemption will not materially adversely affect the ability of the Audit Committee to act independently or to satisfy its other legal requirements.

Compensation Committee. Our Compensation Committee consists of eight members: Sam Oh (chairperson), Gregory A. Beard, Wilson B. Handler, Michael S. Helfer, Ilrae Park, Robert M. Tichio, Donald A. Wagner and Rakesh Wilson. The Compensation Committee is responsible for formulating, evaluating and approving the compensation and employment arrangements of our senior officers. We are a controlled company under NYSE listing rules; as a result, we are not required to have a compensation committee composed entirely of independent directors.

Governance and Nominating Committee. Our Governance and Nominating Committee consists of seven members: Sam Oh (chairperson), Gregory A. Beard, Wilson B. Handler, Ilrae Park, Robert M. Tichio, Donald A. Wagner and Rakesh Wilson. The Governance and Nominating Committee is responsible for assisting the Board in, among other things, effecting the organization, membership and function of the Board and its committees. The Governance and Nominating Committee shall only nominate a director after consulting with the Sponsor or majority-in-interest of the Legacy Class A Stockholders, as applicable, that is entitled to designate such director. See Certain Relationships and Related Transactions, and Director Independence - Stockholders Agreement - Composition of the Board for further details. We are a controlled company under NYSE listing rules; as a result, we are not required to have a governance and nominating committee composed entirely of independent directors.

Code of Ethics

We have adopted a code of ethics, referred to as our Code of Conduct, that applies to all of our directors and employees, including our Chief Executive Officer, Chief Financial Officer and senior financial and accounting officers. In addition to other matters, our Code of Conduct establishes policies to deter wrongdoing and to promote honest and ethical conduct. A copy of our Code of Conduct is available on our website at *www.epenergy.com*. We will post to our website all waivers to or amendments of our Code of Conduct, which are required to be disclosed by applicable law.

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Corporate Governance Guidelines

Our Board has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE. A copy of our corporate governance guidelines is available on our website at *www.epenergy.com*.

ITEM 11. *EXECUTIVE COMPENSATION*

Compensation Discussion and Analysis

The following compensation discussion and analysis provides information relevant to understanding the 2013 compensation of the executive officers identified in the Summary Compensation Table below, to whom we refer as our named executive officers. They include the following individuals:

Name	Title
Brent J. Smolik	Chairman, President and CEO
Dane E. Whitehead	Executive Vice President and CFO
Clayton A. Carrell	Executive Vice President and COO
John D. Jensen	Executive Vice President, Operations Services
Marguerite N. Woung-Chapman	Senior Vice President, General Counsel and Corporate Secretary

The discussion is divided into the following sections:

I. Compensation Objectives
II. Role of Compensation Committee, Compensation Consultant and Management
III. Elements of Total Compensation
IV. 2013 Compensation Decisions
V. Other Compensation Matters

I. Compensation Objectives

Our compensation programs are designed to achieve the following objectives:

- attract, retain and motivate high-performing executive talent, and

- align the interests of our executive officers with both the short-term and long-term interests of our equity holders.

We believe these designs are accomplished by providing our executives with a competitive mix of short-term and long-term compensation, by rewarding superior performance, and by linking a significant portion of pay to measurable performance goals.

II. Role of Compensation Committee, Compensation Consultant and Management Compensation Committee

The Compensation Committee is responsible for overseeing and approving all compensation for our CEO and those executive officers reporting directly to him, which includes all of our named executive officers. The Compensation Committee receives information and advice from its compensation consultant as well as from our human resources department and management to assist in compensation determinations.

Compensation Consultant

In late 2012, the Compensation Committee retained Frederic W. Cook & Co. (FW Cook) as its independent compensation consultant. During 2012, FW Cook advised the committee on incentive plan design and ongoing performance metrics. Commencing in 2013, FW Cook s services have also included advising the Compensation Committee on an ongoing basis on executive officer compensation and the company s general compensation programs, including (i) comparative market data on compensation practices, (ii) incentive plan design, (iii) public offering-related compensation considerations, (iv) updates on compensation trends and regulatory matters affecting compensation and (v) industry best practices. FW Cook attends meetings of the Compensation Committee, participates in the committee s executive sessions, and is directly accountable to the committee. FW Cook is an independent compensation consulting firm and provides no services to us other than the executive compensation consulting services provided to the committee.

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Role of Management and CEO in Determining Executive Compensation

While the Compensation Committee has the responsibility to approve and monitor all compensation for our named executive officers, management plays a supporting role in determining executive compensation. At the Compensation Committee s request, management recommends appropriate company-wide financial and non-financial performance goals. Management works with the Compensation Committee to establish the agenda and prepare meeting information for each Compensation Committee meeting. In addition, our CEO assists the Compensation Committee by providing his evaluation of the performance of the executive officers who report directly to him and recommends compensation levels for such officers. The Compensation Committee evaluates the performance of the CEO and makes compensation decisions for him independently.

III. Elements of Total Compensation Program

The table below summarizes the elements of EP Energy s 2013 executive compensation program. The primary elements of this program were adopted through negotiations between our management team and our Sponsors leading up to the closing of the Acquisition in May 2012.

Compensation Element	Objective	Key Features
Base Salary	To provide a minimum, fixed level cash compensation	Reviewed annually with adjustments made based on individual performance and pay relative to market
Performance-Based Annual Cash Incentive Awards	To motivate and reward named executive officers contributions to achievement of pre-established performance goals, as well as individual performance	Target bonus opportunity established for each named executive officer; actual bonus payable from 0% to 200% of target Paid after year end once the Compensation Committee has determined company performance relative to pre-established performance goals and reviewed individual performance
*Long-Term Equity Awards** *These long-term equity awards were granted in 2012 in the form of equity interests in EPE Acquisition, LLC, our former parent company prior to the Corporate Reorganization in August 2013. In connection with the Corporate Reorganization, the MIPs were converted into Class B common stock and the Class A units were converted into Class A common stock.	To align interests of executive officers with our equity owners and encourage retention	Equity awards granted in 2012 following closing of the Acquisition consisting of following: *Class B Shares (previously referred to as management incentive units, or MIPs)*: • intended to constitute profits interests • issued at no cost to the named executive officers and have value only to the extent the value of company increases • vest ratably over 5 years and supervest in connection with certain liquidity events

No new equity grants were made to our named executive officers during 2013.	• become payable only upon occurrence of certain liquidity events where Sponsors receive a return of at least 1 times their invested capital in the company *Class A Share Matching Grant (previously Class A units)*: • each named executive officer purchased with his or her own funds Class A units in our parent company following the closing of the Acquisition

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Compensation Element	Objective	Key Features
		• named executive officers awarded a matching Class A unit grant equal to 50% of the Class A units purchased • Class A units converted into common stock in connection with Corporate Reorganization • Shares are vested, but subject to transferability restrictions until earlier of 4 years from grant or certain liquidity events and subject to repurchase at the company s election in certain termination scenarios
Qualified 401(k) Plan	To provide retirement savings in a tax-efficient manner	Retirement benefits are provided under the following qualified plan: *401(k) Retirement Plan* • 401(k) plan covering all employees • company contributes an amount equal to 100% of each participant s voluntary contributions under the plan, up to a maximum of 6% of eligible compensation • company contributes an additional retirement contribution equal to 5% of each participant s eligible compensation annually
Health & Welfare Benefits	To provide reasonable health and welfare benefits to executives and their dependents and promote healthy living	Health and welfare benefits available to all employees, including medical, dental, vision and disability coverage Named executive officers also participate in our Senior Executive Survivor Benefits Plan *Senior Executive Survivor Benefits Plan*: • provides executive officers with survivor benefit coverage in lieu of the coverage provided generally to employees under our group life insurance plan in the event of a named executive officer s death • amount of survivor benefit is 2½ times the executive officer s annual salary
Severance	To provide a measure of financial security in the event an executive s employment is terminated without cause	Severance payable in the event of an executive s involuntary termination of employment without cause or termination for good reason, as set forth under the terms of the executive s employment agreement

	Benefits include three times the sum of annual salary plus target bonus for CEO; two times the sum of annual salary plus target bonus for

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Compensation Element	Objective	Key Features
		other named executive officers
Perquisites	Limited perquisites provided to assist executives in carrying out duties and increase productivity	Includes financial planning assistance and subsidized annual physical examinations

Going forward, we expect to continue to provide the same or similar elements of compensation to our named executive officers (with future equity-based award grants to be issued under our Omnibus Incentive Plan).

IV. 2013 Compensation Decisions

2013 Annual Base Salaries and 2013 Target Bonus Opportunities

In connection with the closing of the Acquisition in May 2012, we entered into employment agreements with each of our named executive officers. The employment agreements provide for, among other things, base salaries and annual performance bonus targets. Under the agreements, base salary levels for our named executive officers are reviewed on an annual basis by the Compensation Committee and may be increased at the committee s discretion. During 2013, no changes were made to the named executive officers base salary levels or target bonus opportunities. The following table sets forth the base salaries and annual target bonus opportunities for our named executive officers for 2013.

Annual Base Salaries and

Target Bonus Opportunities

Name	2013 Base Salary ($)	2013 Target Bonus Opportunity (% of salary)(1)
Brent J. Smolik	850,000	100%
Dane E. Whitehead	450,000	100%
Clayton A. Carrell	400,000	100%
John D. Jensen	400,000	100%
Marguerite N. Woung-Chapman	370,000	55%

(1) Actual bonus amounts may be anywhere from 0% - 200% of target.

Annual Cash Incentive Awards for 2013 Performance

2013 Scorecard. In February 2013, the Compensation Committee approved our 2013 scorecard for use in determining 2013 cash incentive awards. The 2013 scorecard consists of five categories of company-wide financial, operational and non-financial performance goals. These scorecard goals were set in alignment with our strategic plan and objectives for the year. Each category includes individual scorecard goals, each with a threshold, target and maximum achievement level, although no one goal is material to the overall scorecard weighting or determination process. The 2013 scorecard categories and weightings are set forth in the following table.

Scorecard Category	**Weighting**
Profit	35%
Production and Reserves	20%
Costs	20%
Value Creation	20%
Health, Safety and Ethics	5%

Range of Individual Bonus Amounts. In addition to company performance, individual performance plays an important role in determining annual incentives. Each named executive officer has individual accountabilities which are evaluated and taken into account

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in determining his or her specific bonus amounts. Pursuant to the terms of the executives employment agreements, the actual percentage of cash incentive bonuses could be at any level between from 0% to 200% of target, based on the company scorecard achievement level and individual performance adjustments.

The range of annual cash incentive bonuses is illustrated as a percentage of base salary for each named executive officer in the following table. The target and maximum amounts are as set forth in the named executive officers individual employment agreements. The threshold amount below is provided for illustrative purposes only and assumes threshold scorecard goal achievement with no individual performance adjustments. As noted above, actual bonus amounts could be at any level between 0% to 200% of target as determined by the Compensation Committee.

Range of Cash Incentive Bonuses as a Percentage of Base Salary for 2013

	Minimum Threshold Not Met	**Threshold**	**Target**	**Maximum**
Brent J. Smolik	0%	50%	100%	200%
Dane E. Whitehead	0%	50%	100%	200%
Clayton A. Carrell	0%	50%	100%	200%
John D. Jensen	0%	50%	100%	200%
Marguerite N. Woung-Chapman	0%	27.5%	55%	110%

The potential range of values of the annual cash incentive awards for 2013 performance for each of the named executive officers is reflected in the Grants of Plan-Based Awards table in the Estimated Possible Payouts Under Non-Equity Incentive Plan Awards column.

EP Energy Scorecard Results. In February 2014, the Compensation Committee reviewed the performance of our company relative to the 2013 scorecard. In reviewing performance relative to the scorecard goals, the Compensation Committee excluded the impacts of certain extraordinary items, including commodity prices changes, the sale during the third quarter of 2013 of certain of our natural gas properties, as well as the sale of our equity interest in Four Star Oil & Gas Company, the unwinding of certain natural gas hedges in connection with the asset sales, production taxes, and adjustment for the mid-year increase in our capital program for incremental drilling and completion activity. The Compensation Committee determined that these items were not related to the ongoing operation of EP Energy in a manner consistent with the way the performance goals and ranges were set for compensation-related purposes. After reviewing each scorecard category and taking into account the adjustments noted above, the Compensation Committee approved a 2013 company scorecard achievement level of 130%.

The Compensation Committee also evaluated each executive officer s individual performance and contributions during 2013 and discussed with our CEO his recommendation as to the appropriate bonus levels for the executive officers reporting to him.

2013 Annual Incentives. Based on the policies described above, the Compensation Committee approved the following annual incentive bonuses for our named executive officers, reflecting both 2013 scorecard achievement as well as individual performance.

Annual Cash Incentives

for 2013 Performance

	Actual Incentive Bonus(1) ($)
Brent J. Smolik	1,100,000
Dane E. Whitehead	610,000
Clayton A. Carrell	540,000
John D. Jensen	540,000
Marguerite N. Woung-Chapman	275,000

(1) Cash incentive awards for the named executive officers will be paid on or prior to March 15, 2014.

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Legacy Long-Term Incentive Award Grants

EPE Acquisition, LLC provided our named executive officers with two forms of long-term equity incentive awards shortly following the closing of the Acquisition in 2012. These awards were designed to align the interests of our named executive officers with that of our equity investors, as described below. No equity awards were issued to our named executive officers during 2013. Below is a summary of these legacy long-term incentive awards.

MIPs/Class B Shares . At the time of the closing of the Acquisition, EPE Acquisition, LLC issued Management Incentive Units (MIPs) to our executive officers, which units were intended to constitute profits interests. 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. The number of MIPs awarded to each named executive officer and his or her respective ownership percentage of the outstanding MIPs (now Class B shares) is set forth in the table below.

MIPs/Class B Shares

Name	**(#)**	**% ownership(1)**
Brent J. Smolik	207,985	23.68%
Dane E. Whitehead	69,328	7.89%
Clayton A. Carrell	69,328	7.89%
John D. Jensen	69,328	7.89%
Marguerite N. Woung-Chapman	27,731	3.16%

(1) Based on 878,304 Class B shares outstanding as of December 31, 2013.

Prior to the Corporate Reorganization, each award of MIPs represented a share in future appreciation of EPE Acquisition, LLC, subject to certain limitations, after the date of grant and once certain shareholder returns have been achieved. The MIPs were subject to time-based vesting requirements and vested ratably over 5 years (20% each year) based on the executive s continued employment with the company. Once vested, the MIPs (or a portion thereof) were generally non-forfeitable in the event of an executive officer s termination of employment for any reason other than cause. In contrast, unvested MIPs would generally be forfeited in the event of an executive officer s termination of employment. While the time vesting component of the MIPs provided forfeiture protection to the executive officers, vesting, in and of itself, would not result in the payment of proceeds to the holder. The MIPs were subject to a performance hurdle and would have become payable only if certain predetermined performance measures were achieved, including the occurrence of certain liquidity events where our Sponsors received a return of at least one times their invested capital in our company. Unvested MIPs held by our named executive officers would immediately vest upon the achievement of such performance measures. In connection with the Corporate Reorganization, all outstanding MIPs were converted into shares of Class B common stock and such shares remain subject to all of the vesting provisions and performance hurdles described above for the MIPs.

Pursuant to our Second Amended and Restated Certificate of Incorporation and subject to certain limitations, holders of Class B common stock are entitled to participate in dividends and distributions of proceeds upon our liquidation. In connection with certain sales of shares of common stock by the Apollo Funds and Riverstone, holders of shares of Class B common stock will have their shares exchanged for shares of common stock that are newly issued by the company (Class B Exchange). The extent to which holders of Class B common stock participate in dividends and distributions of liquidation proceeds will depend on the return on invested capital in the Company and EPE Acquisition, LLC received by our Sponsors and the other Legacy Class A Stockholders, but will in any event be limited to 8.5% of the amount of such returns in excess of such invested capital by the Sponsors and the other Legacy Class A Stockholders. The number of shares of common stock issued in a Class B Exchange will depend on the return on invested capital in the Company and EPE Acquisition, LLC received by the Apollo Funds and Riverstone subject to an adjustment multiple.

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Illustration of Class B Exchange

Below is an example that illustrates the aggregate number of shares of common stock that would be issued in a Class B Exchange assuming a sale by the Apollo Funds and Riverstone of 100% of their common stock holdings on December 31st of each specified year for net proceeds equal to the hypothetical per share prices noted below. The shares would be allocated among the Class B holders, including our named executive officers, in accordance with each holder s respective percentage ownership.

# of Class A Shares Issued in Class B Exchange

(MM shares)			Year Ended December 31, 2014	2015	2016	2017	2018
	$	**20.00**	4.9	4.9	4.9	4.9	4.9
EPE	**$**	**22.50**	6.4	6.4	6.4	6.4	6.4
Share	**$**	**25.00**	7.6	7.6	7.6	7.6	7.6
Price	**$**	**27.50**	8.7	8.7	8.7	8.7	8.7
	$	**30.00**	9.5	9.5	9.5	9.5	9.5

Class A Units/Shares. Each of our named executive officers purchased with his or her own funds Class A units (capital interests) in EPE Acquisition, LLC shortly following the closing of the Acquisition, at a price of $1,000 per unit. In connection with this purchase, each named executive officer was awarded a matching Class A unit grant in an amount equal to 50% of the Class A units purchased. The purchase of the Class A units by our named executive officers represented a significant commitment by our executive team to the future success of our company, and the corresponding grant of the matching units was made to recognize such commitment and further align the interests of our executive team with that of our equity holders. The matching units were vested upon grant, but along with the buy-in units were subject to transferability restrictions until the earliest of four years from grant and certain liquidity events. In addition, the Class A units (both buy-in and matching) were subject to repurchase by the company in the event of certain termination scenarios, as described in Potential Payments upon Termination or Change in Control. All outstanding Class A units (both buy-in and matching) were converted into shares of common stock in August 2013 in connection with the Corporate Reorganization.

Class A Units

Name	Buy-In Units (#)(1)	Matching Units (#)(2)	Total Units (#)(3)
Brent J. Smolik	4,000	2,000	6,000
Dane E. Whitehead	1,700	850	2,550
Clayton A. Carrell	1,200	600	1,800
John D. Jensen	1,200	600	1,800
Marguerite N. Woung-Chapman	740	370	1,110

(1) This column reflects the number of Class A units of EPE Acquisition, LLC that each named executive officer purchased with his or her own funds following the closing of the Acquisition. In connection with the Corporate Reorganization, each Class A unit was converted into one share of common stock. In anticipation of our initial public offering, in January 2014 we completed a 62.553-for-1 stock split of our common stock, resulting in the following holdings of common stock by the named executive officers in respect of their buy in shares: Mr. Smolik: 250,213 shares; Mr. Whitehead: 106,341 shares; Mr. Carrell: 75,064 shares; Mr. Jensen: 75,064; and Ms. Woung-Chapman: 46,289 shares.

(2) This column reflects the matching Class A units awarded to each named executive officer in connection with his or her buy-in of Class A units. In connection with the Corporate Reorganization, each matching unit was converted into one share of common stock. In anticipation of our initial public offering, in January 2014 we completed a 62.553-for-1 stock split of our common stock, resulting in the following holdings of common stock by the named executive officers in respect of their matching shares: Mr. Smolik: 125,107 shares; Mr. Whitehead: 53,170 shares; Mr. Carrell: 37,532 shares; Mr. Jensen: 37,532 shares; and Ms. Woung-Chapman: 23,145 shares.

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V. Other Compensation Matters

Employment Agreements

In connection with the closing of the Acquisition, we entered into employment agreements with each of our named executive officers. These agreements provide us and the executives with certain rights and obligations during and following a termination of employment. We believe these agreements are necessary to protect our legitimate business interests, as well as to protect the executives in the event of certain termination events. The employment agreements provide for, among other things, base salaries, annual performance bonuses and severance benefits in the event of a termination of employment under certain circumstances. The employment agreements became effective as of the closing of the Acquisition. The employment agreements have an initial term that expires on the fifth anniversary of their effective date, but the term of each agreement will be extended automatically for successive additional one-year periods unless either the executive or company provides written notice to the other at least 60 days prior to the end of the then-current initial term or extension term that no such automatic extension will occur. In addition, in connection with entering into the agreement, the executives agreed to waive any rights relating to their participation in El Paso Corporation s change in control severance plan. In connection with the Corporate Reorganization, the employment agreements were assigned to the Company. Additional detail regarding the employment agreements is set forth following the Grants of Plan-Based Awards Table.

One-Time Guaranteed Bonus 2013

In connection with the purchase by our named executive officers of Class A units of EPE Acquisition, LLC following the closing of the Acquisition, each of our named executive officers was awarded a guaranteed cash bonus payable in March 2013, contingent upon the executive s continued employment by us through such date. The guaranteed bonus was awarded in an amount equal to 50% of the value of the Class A units purchased by such executive. The guaranteed bonus was designed to further motivate the executive officers to participate in the buy-in of Class A units of EPE Acquisition, LLC and to encourage retention during the formative months following the closing of the Acquisition. The guaranteed bonus is not a substitute for the annual incentive bonus program described earlier in this Compensation Discussion and Analysis. The amount of each named executive officer s guaranteed bonus payable in 2013 is set forth below.

2013 Guaranteed Bonus

Name	($)
Brent J. Smolik	2,000,000
Dane E. Whitehead	850,000
Clayton A. Carrell	600,000
John D. Jensen	600,000
Marguerite N. Woung-Chapman	370,000

The guaranteed bonus was paid in the first quarter of 2013 and is reflected in the Summary Compensation Table below under the bonus column as part of 2013 compensation.

2014 LTI Program

During 2013, the Compensation Committee reviewed our legacy long term incentive program and considered go-forward long-term incentive approaches for our named executive officers following our initial public offering, taking into consideration retention and ensuring that long-term incentives are directly tied to long-term performance and the creation of stockholder value. Based on this review and with input from FW Cook and management, the Compensation Committee designed a new long term equity program that will commence with the 2014 performance year. Specifically, the Compensation Committee intends to grant stock options and restricted stock issued from our Omnibus Incentive Plan to our executive officers as our go-forward long-term equity program. These equity awards will incorporate a delayed three-year ratable vesting schedule, with one-third vesting as of the earlier of (i) the third-anniversary of the grant date or (ii) the one-year anniversary of a complete sell-down by the Apollo Funds and Riverstone of their shares of our common stock (the first vesting date), one-third vesting on the first anniversary of the first vesting date, and one-third vesting on the second anniversary of the first vesting date. The equity awards are expected to be issued in an approximate 50/50 combination of options and restricted stock, with options granted with an exercise price equal to the closing share price of our common stock on the grant date.

The committee believes this program will encourage retention following a sponsor exist, incentivize superior stock performance over a multi-year period and further align the interests of our named executive officers with our stockholders.

As indicated above, this long-term incentive program is expected to commence in 2014, with grants issued on or around April 1, 2014.

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COMPENSATION COMMITTEE REPORT

We have prepared this Compensation Committee Report as required by the Securities and Exchange Commission. We have reviewed and discussed with EP Energy s management the Compensation Discussion and Analysis required by Item 402(b) of Regulation S-K. Based on that review and discussion, we recommended to the Board of Directors that the Compensation Discussion and Analysis be included in EP Energy s Annual Report on Form 10-K.

COMPENSATION COMMITTEE

Sam Oh, Chairman

Gregory A. Beard

Wilson B. Handler

Michael S. Helfer

Ilrae Park

Robert M. Tichio

Donald A. Wagner

Rakesh Wilson

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EXECUTIVE COMPENSATION

Summary Compensation Table

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)(2)	Stock Awards ($)(3)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)(5)	Total ($)
Brent J. Smolik	2013	850,000	2,000,000			1,100,000		37,827	3,987,827
Chairman, President & Chief Executive Officer	2012	511,063		20,951,593		1,147,500		8,050	22,618,206
Dane E. Whitehead	2013	450,000	850,000			610,000		37,132	1,947,132
Executive Vice President & Chief Financial Officer	2012	270,395		7,167,167		630,000		8,592	8,076,154
Clayton A. Carrell	2013	400,000	600,000			540,000		44,350	1,584,350
Executive Vice President & Chief Operating Officer	2012	240,372		6,917,167		540,000		21,179	7,718,718
John D. Jensen	2013	400,000	600,000			540,000		44,150	1,584,150
Executive Vice President, Operations Services	2012	240,372		6,917,167		510,000		17,222	7,684,761
Marguerite N. Woung-Chapman	2013	370,000	370,000			275,000		29,350	1,044,350
Senior Vice President, General Counsel & Corporate Secretary	2012	222,382		2,896,849		280,000		16,907	3,416,138

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(1) The amounts in this column reflect base salary amounts earned by our named executive officers during the applicable reporting period. For 2012, the amounts reflect base salary amounts earning by our named executive officers on or after the closing of the Acquisition on May 24, 2012 through December 31, 2012, and as such, represent approximately seven months of base salary.

(2) The amount in this column reflects the guaranteed bonus paid in the first quarter of 2013. Please see Compensation Discussion and Analysis for further detail.

(3) The amount in this column for 2012 includes the aggregate grant date fair value of the stock awards granted to each named executive officer during 2012 computed in accordance with the Financial Accounting Standards Board Accounting Standards Codification Topic 718, Compensation - Stock Compensation (FASB ASC Topic 718). This includes the MIPs and the matching Class A unit awards. The grant date fair value used to calculate these amounts is the same as that used for our stock-based compensation disclosure in Note 10 to our consolidated financial statements included elsewhere in this Form 10-K. The aggregate grant date fair value of the MIPs awarded to Messrs. Smolik, Whitehead, Carrell and Jensen and Ms. Woung-Chapman was $18,951,593, $6,317,167, $6,317,167, $6,317,167 and $2,526,849, respectively. The aggregate grant date fair value of the matching Class A units awarded to Messrs. Smolik, Whitehead, Carrell and Jensen and Ms. Woung-Chapman was $2,000,000, $850,000, $600,000, $600,000 and $370,000, respectively. See Compensation Discussion and Analysis for further detail on these grants.

(4) The amount in this column reflects each named executive officer s annual cash incentive bonus. Amounts for 2013 performance will be paid to the named executive officers on or prior to March 15, 2014.

(5) The compensation reflected in the All Other Compensation column for 2013 for each of our named executive officers includes company matching and retirement contributions to our 401(k) Retirement Plan, annual executive physicals and financial planning assistance, which are listed in the table immediately following these footnotes.

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All Other Compensation included in the Summary Compensation Table for 2013

Name	Company Contributions to the 401(k) Retirement Plan ($)	Annual Executive Physicals ($)(A)	Financial Planning ($)(B)	Total ($)
Brent J. Smolik	28,050	1,300	8,477	37,827
Dane E. Whitehead	28,050		9,082	37,132
Clayton A. Carrell	28,050	1,300	15,000	44,350
John D. Jensen	28,050	1,100	15,000	44,150
Marguerite N. Woung-Chapman	28,050	1,300		29,350

(A) The amounts in this column reflect our cost for executive officer annual physicals.

(B) The amounts in this column reflect the cost for financial and tax planning assistance we provided to our named executive officers. This amount is imputed as income and no tax gross-up is provided. Ms. Woung-Chapman elected not to receive financial planning services during 2013.

Grants of Plan-Based Awards

During the Year Ended December 31, 2013

Name	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(1) Threshold ($)	Target ($)	Maximum ($)
Brent J. Smolik				
Short-Term Incentive	N/A	425,000	850,000	1,700,000
Dane E. Whitehead				
Short-Term Incentive	N/A	225,000	450,000	900,000
Clayton A. Carrell				
Short-Term Incentive	N/A	200,000	400,000	800,000
John D. Jensen				
Short-Term Incentive	N/A	200,000	400,000	800,000
Marguerite N. Woung-Chapman				
Short-Term Incentive	N/A	101,750	203,500	407,000

(1) These columns show the potential value of the payout of the annual cash incentive bonuses for 2013 performance for each named executive officer if the threshold, target and maximum performance levels are achieved. The actual amount of the annual cash incentive bonuses earned for 2013 performance is shown in the Summary Compensation Table under the Non-Equity Incentive Plan Compensation column.

Description of Plan-Based Awards

Non-Equity Incentive Plan Awards

The material terms of the non-equity incentive plan awards reported in the above table are described in Compensation Discussion and Analysis above.

Equity Awards

No equity awards were issued to our named executive officers during 2013.

Class A Unit Distributions

In July 2013, the Board of Managers of EPE Acquisition, LLC authorized a cash distribution to all Class A unitholders of our parent on a pro-rata basis, which distribution was made prior to the Corporate Reorganization. Our named executive officers, as owners of Class A units (buy-in units and matching award) received their pro-rata share of the distribution, which was treated as a non-taxable return of investment.

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Employment Agreements

As discussed in the Compensation Discussion and Analysis , we entered into employment agreements with our named executive officers in connection with the closing of the Acquisition. The employment agreements are effective as of May 24, 2012 and have a five-year term. In connection with the Corporate Reorganization, the employment agreements were assigned to the Company. Additional detail regarding the employment agreements is set forth below.

Brent J. Smolik

EPE Acquisition, LLC entered into an employment agreement with Mr. Smolik, effective May 24, 2012, to serve as our President and Chief Executive Officer, as well as the Chairman of the Board of Managers of EPE Acquisition, LLC. Under the terms of the agreement, Mr. Smolik s annual base salary is $850,000, with an annual cash bonus target equal to 100% of his annual base salary, with higher or lower amounts (0% to 200% of target) payable depending on performance relative to targeted results. Mr. Smolik is also entitled to an additional one-time guaranteed bonus of $2,000,000 payable in the first quarter of 2013. Mr. Smolik is eligible to participate in all benefit plans and programs that are available to other senior executives of our company. Mr. Smolik s employment agreement contains provisions related to the payment of benefits upon certain termination events, as well as non-compete, non-solicitation and confidentiality restrictions.

Dane E. Whitehead

EPE Acquisition, LLC entered into an employment agreement with Mr. Whitehead, effective May 24, 2012, to serve as our Executive Vice President and Chief Financial Officer. Under the terms of the agreement, Mr. Whitehead s annual base salary is $450,000, with an annual cash bonus target equal to 100% of his annual base salary, with higher or lower amounts (0% to 200% of target) payable depending on performance relative to targeted results. Mr. Whitehead was also entitled to an additional one-time guaranteed bonus of $850,000 payable in the first quarter of 2013. Mr. Whitehead is eligible to participate in all benefit plans and programs that are available to other senior executives of our company. Mr. Whitehead s employment agreement contains provisions related to the payment of benefits upon certain termination events, as well as certain non-compete, non-solicitation and confidentiality restrictions.

Clayton A. Carrell

EPE Acquisition, LLC entered into an employment agreement with Mr. Carrell, effective May 24, 2012, to serve as our Executive Vice President and Chief Operating Officer. Under the terms of the agreement, Mr. Carrell s annual base salary is $400,000, with an annual cash bonus target equal to 100% of his annual base salary, with higher or lower amounts (0% to 200% of target) payable depending on performance relative to targeted results. Mr. Carrell was also entitled to an additional one-time guaranteed bonus of $600,000 payable in the first quarter of 2013. Mr. Carrell is eligible to participate in all benefit plans and programs that are available to other senior executives of our company. Mr. Carrell s employment agreement contains provisions related to the payment of benefits upon certain termination events, as well as certain non-compete, non-solicitation and confidentiality restrictions.

John D. Jensen

EPE Acquisition, LLC entered into an employment agreement with Mr. Jensen, effective May 24, 2012, to serve as our Executive Vice President, Operations Services. Under the terms of the agreement, Mr. Jensen s annual base salary is $400,000, with an annual cash bonus target equal to 100% of his annual base salary, with higher or lower amounts (0% to 200% of target) payable depending on performance relative to targeted results. Mr. Jensen was also entitled to an additional one-time guaranteed bonus of $600,000 payable in the first quarter of 2013. Mr. Jensen is eligible to participate in all benefit plans and programs that are available to other senior executives of our company. Mr. Jensen s employment agreement contains provisions related to the payment of benefits upon certain termination events, as well as certain non-compete, non-solicitation and confidentiality restrictions.

Marguerite N. Woung-Chapman

EPE Acquisition, LLC entered into an employment agreement with Ms. Woung-Chapman, effective May 24, 2012, to serve as our Senior Vice President, General Counsel & Corporate Secretary. Under the terms of the agreement, Ms. Woung-Chapman s annual base salary is $370,000, with an annual cash bonus target equal to 55% of her annual base salary, with higher or lower amounts (0% to 200% of target) payable depending on performance relative to targeted results. Ms. Woung-Chapman was also entitled to an additional one-time guaranteed bonus of $370,000 payable in the first quarter of 2013. Ms. Woung- Chapman is eligible to participate in all benefit plans and programs that are available to other senior executives of our company. Ms. Woung-Chapman s employment

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agreement contains provisions related to the payment of benefits upon certain termination events, as well as certain non-compete, non-solicitation and confidentiality restrictions.

Outstanding Equity Awards

The following table provides information with respect to outstanding equity awards held by the named executive officers as of December 31, 2013.

Outstanding Equity Awards

at Fiscal Year-End

	Stock Awards	
Name	**Number of Shares or Units of Stock That Have Not Vested (#)(1)**	**Market Value of Shares or Units of Stock That Have Not Vested ($)**
Brent J. Smolik	207,985	(2)
Dane E. Whitehead	69,328	(2)
Clayton A. Carrell	69,328	(2)
John D. Jensen	69,328	(2)
Marguerite N. Woung-Chapman	27,731	(2)

(1) Reflects the total number of shares of Class B common stock (referred to as MIPs prior to the Corporate Restructuring) held by each of our named executive officers as of December 31, 2013. The Class B shares are subject to time-based vesting requirements (vest ratably over 5 years, with 20% vesting on each of May 24, 2013, 2014, 2015, 2016 and 2017) as well as a performance hurdle, and such shares do not become payable until the performance hurdle is achieved (e.g. certain liquidity events in which our Sponsors receive a return of at least one times their invested capital in our company). The performance hurdle applicable to the Class B common shares has not yet been met, and consequently, all of the Class B shares owned by the named executive officers are reported as unvested shares for purposes of this table.

(2) Because the number of shares of common stock that would be issued to our named executive officers in a Class B Exchange depends on the total value received by the Sponsors, the market value of the shares of Class B common stock is not readily determinable. See Compensation Discussion and Analysis for further detail. For illustrative purposes only and assuming that the Apollo Funds and Riverstone sold 100% of their shares of common stock as of the close of our initial public offering on January 23, 2014 for net proceeds of $20 per share, the Class B shares held by our named executive officers would have been exchanged for the following numbers of shares of common stock: Mr. Smolik - 1,164,256; Mr. Whitehead - 388,083; Mr. Carrell - 388,083; Mr. Jensen - 388,083; and Ms. Woung- Chapman - 155,232. These shares of common stock would have the following indicated market values assuming a $20 per share price: Mr. Smolik - $23,285,120; Mr. Whitehead - $7,761,660; Mr. Carrell - $7,761,660; Mr. Jensen - $7,761,660; and Ms. Woung-Chapman - $3,104,640.

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Pension Benefits Table

We do not sponsor a defined benefit pension plan or supplemental executive retirement plan.

Nonqualified Defined Contribution and Other Nonqualified Deferral Compensation Plan

We do not sponsor a nonqualified deferred compensation plan.

Potential Payments upon Termination or Change in Control

The following section describes the benefits that may become payable to our named executive officers in connection with a termination of their employment.

Potential Payments under Employment Agreements

As discussed above, we have entered into employment agreements with our named executive officers. The agreements contain provisions for the payment of severance benefits following certain termination events. Below is a summary of the payments and benefits these named executive officers would receive in connection with various employment termination scenarios.

Under the terms of each employment agreement, if the executive s employment is terminated by us without cause or by the executive with good reason then the executive will be entitled to receive:

- any accrued obligations;
- a lump-sum payment equal to 200% (or 300% in the case of Mr. Smolik) of the sum of the executive s (a) annual base salary and (b) target annual bonus for in the year in which the termination of employment occurs;
- a prorated annual bonus based on the executive s target bonus opportunity for the year of termination; and

- continuation of basic life and health insurance following termination for 24 months (or 36 months in the case of Mr. Smolik).

If the executive s employment is terminated for any other reason, our only obligation will be the payment of any accrued obligations. For purposes of the above, good reason means, as to any executive, the occurrence of any of the following events without the executive s consent: (a) a reduction in the executive s annual base salary other than a reduction of not more than 5% in connection with a general reduction in base salaries that affects all similarly situated executives in substantially the same proportions which is implemented in response to a material downturn in the U.S. domestic oil and natural gas exploration and development industry; (b) a failure of the company to cause the executive to be eligible under benefit plans that provide benefits that are substantially comparable in the aggregate to those provided to executive as of the effective date of the employment agreement; (c) any material breach by the company of the employment agreement; (d) a material diminution in the executive s title, authority, duties, or responsibilities; (e) the requirement that the executive s principal place of employment be outside a 35 mile radius of his or her then-current principal place; (f) any purported termination of the executive s employment for cause which does not comply with the employment agreement; and solely with respect to Mr. Smolik, (g) the failure of the company to re-elect him as a member of the board in connection with any election of managers. The term cause means the executive s (i) willful failure to perform the executive s material duties, (ii) willful and material breach of the employment agreement, (iii) conviction of or plea of guilty or no contest to, any felony or any crime involving moral turpitude, or (iv) engaging in actual fraud or willful material misconduct in the performance of the executive s duties under the employment agreement.

Potential Payments under Welfare Benefit Plans

We sponsor a welfare benefit plan available to all employees that provides long-term disability benefits in the event of an employee s permanent disability. In the event of a named executive officer s permanent disability, disability income would be payable on a monthly basis as a long as the executive officer qualified as permanently disabled. Long-term disability benefits are equal to 60% of the executive s base salary in effect immediately prior to the disability, with a maximum monthly benefit equal to $25,000. In the event of a named executive officer s permanent disability, he or she may also elect to maintain basic life and health insurance coverage under our welfare benefit plan at active-employee rates for as long as the individual qualifies as permanently disabled or until he or she reaches age 65.

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In addition, our named executive officers participate in our Senior Executive Survivor Benefits Plan, which provides each of our named executive officers with survivor benefits coverage in the event of the executive s death in lieu of the coverage provided generally under our group life insurance plan. The amount of benefits provided is 2.5 times the executive s annual salary.

Estimated Severance, Disability and Survivor Benefits

The following table presents the company s estimate of the amount of the benefits to which each of the named executive officers would have been entitled had his or her employment been terminated or a change in control occurred on December 31, 2013 under the scenarios noted below.

Name	Voluntary Termination Without Good Reason or Involuntary Termination with Cause ($)	Death ($)	Disability ($)(1)	Involuntary Termination without Cause or Voluntary Termination with Good Reason ($)	Change in Control (no termination) ($)
Brent J. Smolik					
Severance Payment				5,950,000	
Continued Medical			17,298	51,894	
Disability Income			300,000		
Survivor Benefit		2,125,000			
Dane E. Whitehead					
Severance Payment				2,250,000	
Continued Medical			17,298	34,596	
Disability Income			270,000		
Survivor Benefit		1,125,000			
Clayton A. Carrell					
Severance Payment				2,000,000	
Continued Medical			17,298	34,596	
Disability Income			240,000		
Survivor Benefit		1,000,000			
John D. Jensen					
Severance Payment				2,000,000	
Continued Medical			17,298	34,596	
Disability Income			240,000		
Survivor Benefit		1,000,000			
Marguerite N. Woung-Chapman					
Severance Payment				1,350,500	
Continued Medical			8,094	16,188	
Disability Income			222,000		
Survivor Benefit		925,000			

(1) Disability income would be payable on a monthly basis as long as the executive officer qualifies as permanently disabled. The amounts in this column assume disability income and continued benefit coverage for a period of one year.

Treatment of Equity Awards

In addition to the severance and welfare benefits described above, our named executive officers outstanding equity awards may be impacted in the event of certain termination scenarios, as described below.

Common Stock

As discussed in the Compensation Discussion and Analysis, the Class A units of EPE Acquisition, LLC issued to the named executive officers during 2012, including the buy-in units purchased by the executives and matching units awarded in connection with such purchase, were 100% vested upon grant, but were granted subject to transfer restrictions until the earliest of four years from grant and certain liquidity events. The shares of Class A common stock issued to the named executive officers in exchange for such Class A units remain subject to the same vesting and transfer restrictions. In addition, the units were, and following the Corporate

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Reorganization the corresponding shares are, subject to repurchase at the company s election in certain termination scenarios as follows:

Voluntary Termination without Good Reason or Involuntary Termination with Cause

In the event of a named executive officer s voluntary termination without good reason or if the executive s employment is terminated by the company with cause, then for a period of one year following the termination, the company would be able to elect (but would not be required) to repurchase the Class A units or shares of Class A common stock, as applicable, held by such executive for a purchase price equal to the lesser of the original cost paid by the executive to purchase the units and the fair market value of the units or shares, as applicable (as determined by the Board), on the repurchase date. As the matching Class A units were awarded to the executives at no cost, this repurchase option would cause the units or shares of common stock, as applicable, to be repurchased for no consideration.

Involuntary Termination without Cause or Voluntary Termination with Good Reason or Termination due to Death or Disability

In the event of a named executive officer s involuntary termination by the company without cause or termination by the executive with good reason, or in the event of the named executive officer s death or disability, the company would be able to elect (but would not be required) to repurchase the Class A units or shares of Class A common stock, as applicable, held by such executive for a purchase price equal to the fair market value of the units or shares, applicable (as determined by the Board), on the repurchase date.

Class B Common Stock

As discussed in the Compensation Discussion and Analysis, the MIPs awarded to the named executive officers during 2012 were scheduled to vest ratably over five years, and the corresponding shares of Class B common stock remain subject to the same vesting schedule. Below is a description of the impact of certain termination scenarios on the MIP awards prior to the Corporate Reorganization, and the Class B common stock following the Corporate Reorganization.

Involuntary Termination with Cause

In the event of a named executive officer s termination with cause, all MIPs or Class B common stock, as applicable, held by such executive (whether vested or unvested) would be forfeited without consideration.

Voluntary Termination without Good Reason

In the event of a named executive officer s voluntary termination, 25% of the executive s vested MIPs and all unvested MIPs or Class B common stock, as applicable, would be forfeited without consideration. In such event, the company would be able to elect (but would not be required) to redeem the non- forfeited MIPs or shares of Class B common stock, as applicable, held by such executive at the fair market value of such MIPs or shares, as applicable (as determined by the Board) on the repurchase date.

Involuntary Termination without Cause or Voluntary Termination with Good Reason or Termination due to Death or Disability

In the event of a named executive officer s involuntary termination by the company without cause or termination by the executive with good reason, or in the event of the named executive officer s death or disability, a pro-rata portion of the unvested MIPs or Class B common stock, as applicable, would vest as of the termination date (pro-rata vesting relating solely to the single tranche of MIPs or Class B common stock, as applicable, that would have vested as of the next vesting date). All remaining unvested MIPs or Class B common stock, as applicable, would be forfeited without consideration. In such event and for a period of one year following the termination, the company would be able to elect (but would not be required) to redeem the non-forfeited MIPs or shares of Class B common stock, as applicable, held by such executive at the fair market value of such MIPs or shares, as applicable (as determined by the Board), on the repurchase date.

Director Compensation

During 2013, members of our Board did not receive a retainer or board meeting fees from us for serving on the Board. Members of the Board were reimbursed for their reasonable expenses for attending board functions. Commencing in 2014, our independent non-employee directors will receive cash and equity-based compensation for their services as directors, as follows:

- an annual cash retainer of $70,000;

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- an additional annual cash retainer of $7,500 for membership on the Audit Committee and $5,000 for membership on the Compensation Committee or any other board committee;

- an additional annual retainer of $15,000 for service as the chair of the Audit Committee or the Compensation Committee and $10,000 for service as the chair of any other board committee;

- an additional annual cash retainer of $20,000 for service as the lead director; and

- an annual award of restricted stock granted under our Omnibus Incentive Plan, having a value as of the grant date of $175,000.

Annual cash retainers will be paid in quarterly installments at the end of each quarter, unless the director elects to receive the retainer in the form of restricted stock. Annual equity grants will be made each year on the date of the Company s annual meeting of stockholders (or in the case of 2014, on May 1, 2014) and an independent director who joins the Board at any time other than the annual meeting will receive a pro-rated grant as of the first business day of the month following the director s appointment to the Board. Directors may, at their election, receive their annual cash retainer in the form of restricted stock, which award would be issued at the same time as the annual equity grant and would be subject to the same vesting restrictions. Directors will also receive reimbursement for out-of-pocket expenses associated with attending board or committee meetings and director and officer liability insurance coverage.

Compensation Committee Interlocks and Insider Participation

Our Compensation Committee is composed of Sam Oh, Gregory A. Beard, Wilson B. Handler, Michael S. Helfer, Ilrae Park, Robert M. Tichio, Donald A. Wagner and Rakesh Wilson. No member of the Compensation Committee is a former or current officer or employee of the Company. In addition, none of our executive officers serve (i) as a member of the compensation committee or board of directors of another entity, one of whose executive officers serve on our Compensation Committee, or (ii) as a member of the compensation committee of another entity, one of whose executive officers serve on our Board.

ITEM 12. *SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS*

PRINCIPAL STOCKHOLDERS

The following table provides certain information regarding the beneficial ownership of our outstanding common stock as of February 15, 2014, for:

- each person or group who beneficially owns more than 5% of our common stock;
- each of our directors;
- each of the named executive officers in the Summary Compensation Table; and
- all of our current executive officers and directors as a group.

The percentage of ownership is based on 243,877,539 shares of common stock outstanding as of February 15, 2014.

The amounts and percentages of common stock beneficially owned are reported on the basis of SEC regulations governing the determination of beneficial ownership of securities. Under the SEC rules, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or to direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities and a person may be deemed a beneficial owner of securities as to which he has no economic interest. Except as indicated by footnote and in the next paragraph, the persons named in the table below have sole voting and investment power with respect to all shares of common stock shown as beneficially owned by them.

Our Sponsors, as a group, continue to control a majority of our voting common stock. As a result, we qualify as a controlled company under the NYSE listing rules. However, the number of shares reflected in the table below as beneficially owned by each of the Sponsors does not include shares held by the other Sponsors that are subject to the terms of the Stockholders Agreement pursuant to which, among other things, the Sponsors have agreed to act together to vote for the election of each of their director nominees to the Board.

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Name of Beneficial Owner	Shares of Common Stock Beneficially Owned Shares	Percentage
Apollo Funds(1)	112,596,207	46.2%
Riverstone(2)	31,276,726	12.8%
Access(3)	34,943,104	14.3%
KNOC(4)	31,276,726	12.8%
Brent J. Smolik	375,320	*
Dane E. Whitehead	159,511	*
Clayton A. Carrell	112,596	*
John D. Jensen	112,596	*
Marguerite N. Woung-Chapman	69,434	*
Ralph Alexander		
Gregory A. Beard		
Wilson B. Handler		
John J. Hannan		
Michael S. Helfer	2,564	*
Ilrae Park		
Sam Oh		
Robert M. Tichio		
Donald A. Wagner		
Rakesh Wilson		
Directors and executive officers as a group (16 persons)	888,319	*

* Less than 1%.

(1) Includes shares held of record by AIF PB VII (LS AIV), L.P. (AIF LS AIV), AIF VII (AIV), L.P. (AIF VII), AOP VII (EPE Intermediate), L.P. (AOP Intermediate), AP VII 892/TE (EPE AIV I), L.P. (AP EPE I), AP VII 892/TE (EPE AIV II), L.P. (AP EPE II), AP VII 892/TE (EPE AIV III), L.P. (AP EPE III), AP VII 892/TE (EPE AIV IV), L.P. (AP EPE IV), Apollo Investment Fund (PB) VII, L.P. (AIF (PB) VII), ANRP (EPE AIV), L.P. (ANRP EPE), ANRP (EPE Intermediate), L.P. (ANRP Intermediate), ANRP 892/TE (EPE AIV), L.P. (ANRP 892), EPE Domestic Co-Investors, L.P. (Domestic Co-Investors), EPE Overseas Co-Investors (FC), L.P. (Overseas Co-Investors), EPE 892 Co-Investors I, L.P. (Co-Investor I), EPE 892 Co-Investors II, L.P. (Co-Investor II), and EPE 892 Co-Investors III, L.P. (Co-Investor III, and together with AIF LS AIV, AIF VII, AOP Intermediate, AP EPE I, AP EPE II, AP EPE III, AP EPE IV, AIF (PB) VII, ANRP EPE, ANRP Intermediate, ANRP 892, Domestic Co-Investors, Overseas Co-Investors, Co-Investor I and Co-Investor II, the Apollo Funds). Apollo Management VII, L.P. (Management VII) is the manager of AIF LS AIV, AIF VII, AOP Intermediate, AP EPE I, AP EPE II, AP EPE III, AP EPE IV and AIF (PB) VII. Apollo Commodities Management, L.P. with respect to Series I (Commodities Management) is the manager of ANRP EPE, ANRP Intermediate and ANRP 892. EPE Acquisition Holdings, LLC (Acquisition Holdings) is the general partner of Domestic Co-Investors, Overseas Co-Investors, Co-Investor I, Co-Investor II and Co-Investor III. Management VII and Commodities Management are the members and managers of Acquisition Holdings. AIF VII Management, LLC (AIF VII LLC) is the general partner of Management VII. Apollo Management, L.P. (Apollo Management) is the sole member-manager of AIF VII LLC. Apollo Management GP, LLC (Management GP) is the general partner of Apollo Management. Apollo Commodities Management GP, LLC (Commodities GP) is the general partner of Commodities Management. Apollo Management Holdings, L.P. (Management Holdings) is the sole member and manager of Management GP and of Commodities GP. Apollo Management Holdings GP, LLC (Management Holdings GP) is the general partner of Management Holdings. Leon Black, Joshua Harris and Marc Rowan are the managers, as well as executive officers, of Management Holdings GP, and as such may be deemed to have voting and dispositive control of the capital stock beneficially owned by the Apollo Funds. The address of each of AIF LS AIV, AIF VII, AOP Intermediate, AP EPE I, AP EPE II, AP EPE III, AP EPE IV, AIF (PB) VII, ANRP 892, Domestic Co-Investors, Co-Investor I, Co-Investor II and Co-Investor III is One Manhattanville Road, Suite 201, Purchase, New York 10577. The address of Overseas Co-Investors is c/o Intertrust Corporate Services (Cayman) Limited, 190 Elgin Street, George Town, Grand Cayman KY1-9005, Cayman Islands. The address of ANRP EPE, ANRP Intermediate, Management VII, Commodities Management, Acquisition Holdings, AIF VII LLC, Apollo Management, Management GP, Commodities GP, Management Holdings and Management Holdings GP, and Messrs. Black, Harris and Rowan, is 9 W. 57th Street, 43rd Floor, New York, New York 10019.

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(2) Riverstone V Everest Holdings, L.P. and Riverstone V FT Corp Holdings, L.P. are the record holders of 19,942,040 shares of common stock and 11,334,686 shares of common stock, respectively. Riverstone Energy Partners V, L.P. is the general partner of each of Riverstone V Everest Holdings, L.P. and Riverstone V FT Corp Holdings, L.P. Riverstone Energy GP V, LLC is the general partner of Riverstone Energy Partners V, L.P. Riverstone Energy GP V, LLC is managed by a seven person managing committee. Pierre F. Lapeyre, Jr., David M. Leuschen, John Browne, James T. Hackett, Michael B. Hoffman, N. John Lancaster and Andrew W. Ward, as the members of the managing committee of Riverstone Energy GP V, LLC, may be deemed to share beneficial ownership of the shares of common stock owned of record by Riverstone V Everest Holdings, L.P. and Riverstone V FT Corp Holdings, L.P. These individuals expressly disclaim any such beneficial ownership. The business address for each of the persons named in this footnote is c/o Riverstone Holdings, 712 Fifth Avenue, 36th Floor, New York, NY 10019.

(3) Represents beneficial ownership attributable to record ownership of 31,276,726 shares of common stock by Texas Oil & Gas Holdings LLC (TOGH). Each of RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Access Industries Management, LLC and Len Blavatnik may be deemed to beneficially own the shares of common stock held directly by TOGH. RSB Limited holds a majority of the outstanding membership interests in TOGH and, as a result, may be deemed to share voting and investment power over the shares of common stock held directly by TOGH. Access Industries Holdings LLC holds a majority of the outstanding voting interests in RSB Limited and, as a result, may be deemed to share voting and investment power over the shares of common stock beneficially owned by TOGH and RSB Limited. Access Industries, LLC holds a majority of the outstanding voting membership interests in Access Industries Holdings LLC and, as a result, may be deemed to share voting and investment power over the shares of common stock beneficially owned by TOGH, RSB Limited and Access Industries Holdings LLC. Access Industries Management, LLC controls Access Industries Holdings LLC, Access Industries, LLC and TOGH and, as a result, may be deemed to share voting and investment power over the shares of common stock beneficially owned by TOGH, RSB Limited, Access Industries Holdings LLC and Access Industries, LLC. Len Blavatnik controls Access Industries Management, LLC and a majority of the outstanding voting interests in Access Industries, LLC and, as a result, may be deemed to share voting and investment power over the shares of common stock beneficially owned by TOGH, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC and Access Industries Management, LLC. Because of their relationships with TOGH, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Access Industries Management, LLC and Len Blavatnik, AI Energy Holding LLC (AIEH), AI Value Holdings, LLC (AIVH), Altep 2014 L.P. (Altep 2014) and Access Industries, Inc. may be deemed to share voting and investment power over the shares of common stock beneficially owned by TOGH, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Access Industries Management, LLC and Len Blavatnik. Each of RSB Limited, Access Industries Holdings LLC, Access Industries, LLC and Access Industries Management, LLC, AIEH, AIVH, Altep 2014, Access Industries, Inc. and Len Blavatnik, and each of their affiliated entities and the officers, partners, members, and managers thereof, other than TOGH, disclaims beneficial ownership of the shares held by TOGH. Also represents beneficial ownership of 3,556,387 shares of common stock held directly by AIEH. Each of AIVH, Access Industries Management, LLC and Len Blavatnik may be deemed to beneficially own the shares of common stock held directly by AIEH. AIVH is the sole member of AIEH and, as a result, may be deemed to share voting and investment power over the shares of common stock beneficially owned by AIEH. Access Industries Management, LLC controls AIVH and, as a result, may be deemed to share voting and investment power over the shares beneficially owned by AIEH. Len Blavatnik controls Access Industries Management, LLC and, as a result, may be deemed to share voting and investment power over the shares of common stock beneficially owned by AIEH. Because of their relationships with AIEH, AIVH, Access Industries Management, LLC and Len Blavatnik, TOGH, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Altep 2014 and Access Industries, Inc. may be deemed to share voting and investment power over the shares of common stock beneficially owned by AIEH, AIVH, Access Industries Management, LLC and Len Blavatnik. Each of AIVH, Access Industries Management, LLC, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Altep 2014, Access Industries, Inc. and Len Blavatnik, and each of their affiliated entities and the officers, partners, members and managers thereof, other than AIEH, disclaims beneficial ownership of the shares held by AIEH. Also represents beneficial ownership of 109,991 shares of common stock held directly by Altep 2014. Each of Access Industries, Inc. and Len Blavatnik may be deemed to beneficially own the shares of common stock held directly by Altep 2014. Access Industries, Inc. is the general partner of Altep 2014 and, as a result, may be deemed to have voting and investment control over the shares owned directly by Altep 2014. Len Blavatnik controls Access Industries, Inc. and, as a result, may be deemed to share voting and investment power over the shares of common stock held by Altep 2014. Because of their relationships with Altep 2014, Access Industries, Inc. and Len Blavatnik, each of TOGH, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, AIEH and AIVH may be deemed to share voting and investment power over the shares of common stock beneficially owned by Altep 2014, Access Industries, Inc. and Len Blavatnik. Each of Access Industries, Inc., RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Access Industries Management, LLC, AIEH, AIVH and Len Blavatnik, and each of their affiliated entities and the officers, partners, members and managers thereof, other than Altep 2014, disclaims beneficial ownership of the shares held by Altep 2014. The address for TOGH, RSB Limited, Access Industries Holdings LLC, Access

Industries, LLC, Access Industries Management, LLC, AIEH, AIVH, Altep 2014, Access Industries, Inc. and Len Blavatnik is c/o Access Industries, Inc., 730 Fifth Avenue, 20th Floor, New York, NY 10019.

(4) KNOC is the state-owned oil and gas company of the Republic of Korea. Moon Kyu Suh, Joong Hyun Kim, Kap Young Ryu, Byung Jin Song, Kang Hyun Shin, Joo Heon Park, Ho Cheul Shin, Jae Hyun Kim, Jong Kyu Yoon, One Shick Shin, Gye Hyung Lee and Byung Og Ahn, as directors of KNOC (collectively, the KNOC Directors and each, a KNOC Director), , exercise investment and voting power with respect to the shares of common stock owned by KNOC. Based on the foregoing relationships, each of the KNOC Directors may be deemed to be the beneficial owners of the shares of common stock owned by KNOC. Each KNOC Director disclaims beneficial ownership of such shares of common stock except to the extent of his or her pecuniary interest therein. The address of each KNOC Director and KNOC is c/o Korea National Oil Corporation, 57 Gwampyeong-ro212beong-gil, Dongan-gu, Anyang, Gyeonggido, Korea 431-711.

ITEM 13. *CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE*

Corporate Reorganization

In connection with our Corporate Reorganization, we engaged in certain transactions with certain affiliates and the members of EPE Acquisition, LLC, as described below.

On August 30, 2013, we reorganized to form a new corporate holding structure, which we refer to herein as the Corporate Reorganization. Prior to the Corporate Reorganization, we historically held our business through EPE Acquisition, LLC, which had two classes of membership interests: Class A membership units (which were beneficially owned by the Legacy Class A Stockholders) and Class B membership units (which were beneficially owned by the Legacy Class B Stockholder). Class A membership units represented full value or capital interests, and Class B membership units represented profits interests. The Corporate Reorganization was effected in order to allow us to hold our business in corporate form.

Incorporation and Equity Contribution

In connection with the Corporate Reorganization, (i) EPE Acquisition, LLC caused the initial incorporation of EP Energy Corporation, (ii) certain Legacy Class A Stockholders contributed their Class A membership interests in EPE Acquisition, LLC to EP Energy Corporation in exchange for the issuance by EP Energy Corporation to such Legacy Class A Stockholders of shares of common stock, which have substantially the same interests, rights and obligations as such holder s respective Class A membership interests in EPE Acquisition, LLC, (iii) certain other Legacy Class A Stockholders, which previously held their Class A membership interests in EPE Acquisition, LLC indirectly through other entities (the Blocker Vehicles), contributed their ownership interests in their Blocker Vehicles to EP Energy Corporation (such that EP Energy Corporation now indirectly owns such membership interests in EPE Acquisition, LLC through the Blocker Vehicles) in exchange for the issuance by EP Energy Corporation to such indirect holders of shares of common stock, which have substantially the same interests, rights and obligations as such indirect holder s respective Class A membership interests in EPE Acquisition, LLC, and (iv) the Legacy Class B Stockholder contributed its Class B membership interests in EPE Acquisition, LLC to EP Energy Corporation in exchange for the issuance by EP Energy Corporation to such holders of shares of Class B common stock, which have substantially the same interests, rights and obligations as its Class B membership interests in EPE Acquisition, LLC, in cancellation of its Class B membership interests in EPE Acquisition, LLC. As a result of the Corporate Reorganization, EP Energy Corporation owns, directly, or indirectly through the Blocker Vehicles, 100% of the equity interests in

EPE Acquisition, LLC. The members of our management team and certain employees that indirectly beneficially own shares of our Class B common stock will have the right, under certain circumstances, to exchange their shares of Class B common stock for shares of our common stock. See Description of Capital Stock - Class B Exchange.

As described above, certain indirect beneficial owners of EPE Acquisition, LLC became direct stockholders of EP Energy Corporation as a result of contributing their ownership interests in the Blocker Vehicles to EP Energy Corporation. Such stockholders agreed to indemnify us from and against any liabilities arising from or relating to the participation of such Blocker Vehicles in the contribution and any taxes of such Blocker Vehicles for periods (or portions thereof) ending on or before the date of the Corporate Reorganization.

Related Agreements and Issuance

In connection with the Corporate Reorganization, we entered into the Stockholders Agreement, Registration Rights Agreement and certain other agreements with the Legacy Stockholders.

Following the Corporate Reorganization, we issued an additional 70,000 shares of Class B common stock to EPE Employee Holdings II, LLC, a vehicle through which we will grant to our current and future employees awards representing the right to receive

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the proceeds paid in respect of such shares of Class B common stock pursuant to the Second Amended and Restated Certificate of Incorporation, which proceeds shall in all events be distributed to such grantees within six months of EPE Employee Holdings II, LLC receipt thereof. The grant of any such incentive awards to our non-officer employees shall be at the discretion of our Chief Executive Officer. The grant of any such incentive awards to our officers shall be at the discretion of our Compensation Committee; provided, that our Chief Executive Officer may recommend officer grants to our Compensation Committee for its consideration.

On January 2, 2014, we effected a 62.553-for-one stock split with regard to our outstanding shares of common stock.

Stockholders Agreement

We entered into a Stockholders Agreement with the Legacy Class A Stockholders and the Legacy Class B Stockholder, dated as of August 30, 2013 (the Stockholders Agreement), in connection with our Corporate Reorganization. The Stockholders Agreement contains, among other things, the agreement among the stockholders to restrict their ability to transfer our stock as well as rights of first refusal, tag-along rights and drag-along rights. Pursuant to the Stockholders Agreement, certain of the Legacy Class A Stockholders have, subject to certain exceptions, preemptive rights to acquire their pro rata portion of any future issuances of additional securities of EP Energy Corporation. The Stockholders Agreement also permits us to repurchase common stock and Class B common stock beneficially owned by management, and allows such beneficially owned shares to be forfeited, under certain conditions. See Management - Executive Compensation - Treatment of Equity Awards .

Restrictions On Stock Transfers

Subject to certain exceptions, including the exercise of rights of first refusal, tag-along rights, drag-along rights and registration rights, shares of our common stock may not be transferred by any Legacy Stockholder to any person other than permitted transferees, including affiliates of such Legacy Stockholder. These transfer restriction will survive until the earlier of (i) May 24, 2016 and (ii) the second anniversary of the consummation of a Qualified Offering (as defined below). Legacy Stockholders may also transfer their shares of our common stock with the approval of a majority of our directors on the Board, other than those directors that are a party, or affiliated with a party, to such transfer or have otherwise been designated by a Legacy Class A Stockholder that is a party to such transfer. These transfer restrictions will terminate upon a change of control of the Company.

Rights of First Refusal

Prior to making any transfer of shares of Class A common stock (other than certain customary permitted transfers, transfers in connection with a drag-along sale, transfers in connection with the exercise of tag-along rights, transfers pursuant to the exercise of registration rights under the Registration Rights Agreement or transfers following the consummation of a public offering in which (i) the cash proceeds to the Company and shareholders (without deducting underwriting discounts, expenses and commissions) are at least $250,000,000, (ii) the shares are listed on a national securities exchange, and (iii) the MOIC following the consummation of such public offering would be at least two (2.0) (a Qualified Offering)), any prospective selling Legacy Class A Stockholder shall notify the Company, the Sponsors and certain major Legacy Class A Stockholders (each, an Eligible Class A Stockholder) of such proposed transfer and the terms of such transfer. Each Eligible Class A Stockholder shall have the right to purchase its *pro rata* portion of the shares of Class A common stock proposed to be sold by such prospective selling Legacy Class A Stockholder. To the extent that the Eligible Class A Stockholders do not elect to purchase all of the shares of Class A common stock proposed to be transferred by such prospective selling Legacy Class A Stockholder, the Company will be entitled to purchase all or any portion of any remaining shares of Class A common stock proposed to be transferred by such prospective selling Legacy Class A Stockholder and if the Company and the Eligible Class A Stockholders do not elect to purchase all of the shares of Class A common stock proposed to be sold by such prospective selling Legacy Class A Stockholder, the remaining portion of such shares of Class A common stock may be transferred by such prospective selling Legacy Class A Stockholder.

Tag-Along Rights

Prior to making any transfer of shares of Class A common stock (other than certain customary permitted transfers, transfers pursuant to the exercise of registration rights under the Registration Rights Agreement or transfers in connection with a drag-along sale and subject to the exercise of the rights of first refusal described above), any prospective selling Legacy Class A Stockholder shall notify each other Legacy Class A Stockholder of such proposed transfer and the terms of such transfer. Each Legacy Class A Stockholder (including such prospective selling Legacy Class A Stockholder) shall have the right to participate in such transfer on the same terms as those proposed by such prospective selling Legacy Class A Stockholder and in the event that the prospective buyer is only willing to acquire less than all of the shares of Class A common stock that such prospective selling Legacy Class A Stockholder and the other participating Legacy Class A Stockholders desire to sell, then such prospective selling Legacy Class A Stockholder and the other participating Legacy Class A Stockholders shall be entitled to include in such transfer, their *pro rata portion* of the number of shares of Class A common stock that such prospective buyer is willing to acquire. To the extent that the other Legacy Class A

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Stockholders do not elect to sell the maximum number of such shares of Class A common stock that they are entitled to sell pursuant to the exercise of these tag-along rights, the remaining portion of such shares of Class A common stock may be transferred by such prospective selling Legacy Class A Stockholder. These tag-along rights will terminate upon the earlier of a Qualified Offering and a change of control of the Company.

Drag-Along Rights

If (i) we or any Legacy Class A Stockholder receives an offer from a prospective third party buyer to acquire our Class A common stock in a transaction which would result in a change of control of the Company, (ii) such transaction has received Special Board Approval (except that after May 24, 2017, such transaction need only be approved by the Apollo Funds or the Legacy Class A Stockholders holding at least 40% of our outstanding Class A common stock), (iii) at least 80% of the consideration offered by such prospective buyer consists of cash or marketable securities, and (iv) the MOIC following the consummation of such transaction would be at least two (2.0), then we or such Legacy Class A Stockholder that receives such offer shall notify the other Legacy Class A Stockholders of the terms of such offer. Each Legacy Class A Stockholder will be required to vote in favor of and not oppose such transaction and sell its shares of Class A common stock to the prospective buyer and receive the same form and amount of consideration to be received by each other Legacy Class A Stockholder in such transaction. These drag-along rights will terminate upon a change of control of the Company.

Preemptive Rights

Each Legacy Class A Stockholder has the right to purchase its *pro rata* share of any new shares of common stock or any other equity or debt securities that we may propose to sell and issue. Legacy Class A Stockholders will not have preemptive rights with respect to the following issuances of securities by us: (i) any issuance of securities upon the exercise of options, warrants, debentures or other convertible securities outstanding as of August 30, 2013 or issued after August 30, 2013 in a transaction that complies with the preemptive rights provisions of the Stockholders Agreement, (ii) any issuance of securities to our officers, employees, managers or consultants pursuant to such person s employment or consulting arrangements with us, (iii) any issuance of securities as part of (a) any direct or indirect consolidation, business combination or other acquisition transaction or (b) any joint venture or strategic partnership entered into primarily for purposes other than raising capital, in each case, to the extent approved by a majority of our directors on the Board, other than those directors that are a party, or affiliated with a party, to such transaction or have otherwise been designated by a Legacy Class A Stockholder that is a party to such transaction, (iv) any issuance of securities in connection with any share split, share dividend or similar distribution or recapitalization, (v) any issuance of securities pursuant to a registered public offering or in connection with an initial public offering, (vi) any issuance of shares of Class A common stock in exchange for shares of Class B common stock, and (vii) the issuance of 70,000 shares of Class B common stock to EPE Employee Holdings II, LLC contemplated by the Stockholders Agreement. These preemptive rights will terminate upon the earlier of a Qualified Offering and a change of control of the Company.

Composition of the Board

The Stockholders Agreement also provides the Sponsors with certain rights with respect to the designation of directors to serve on our Board. Our Board is initially comprised of not less than 11 directors, (i) five of whom are designated by the Apollo Funds, (ii) two of whom are designated by Riverstone, (iii) one of whom is designated by Access, (iv) one of whom is designated by KNOC, (vi) one of whom is our chief executive officer and (vii) one of whom is an independent director designated by the Apollo Funds. Pursuant to the Stockholders Agreement, the Apollo Funds have the right to designate any director as the Chairman of the Board. The Apollo Funds have the right to and will designate one additional independent director within one year of the Effective Time and Riverstone has the right to and will designate an independent director within 90 days of the Effective Time. Upon the designation of such independent directors, our Board will comprise of a total of 13 directors, of which three will be independent of us, the Legacy Stockholders and their affiliates under the rules of the NYSE.

As ownership in us by a Sponsor decreases, the Stockholders Agreement provides for the reduction in the number of directors such Sponsor may designate. The tables below state the number of director(s) that each Sponsor may designate to the Board pursuant to the Stockholders Agreement based on such Sponsor s ownership of common stock, in each case, expressed as a percentage of its ownership of common stock as of the Effective Time (e.g., 75% means that the Sponsor holds 75% of the common stock that it held as of the Effective Time).

Apollo Ownership	**Non-Independent Directors**	**Independent Directors**
At least 75%	5	2
Between 50% and 75%	4	2
Between 25% and 50%	2	1
Between 10% and 25%	1	0
Less than 10%	0	0

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Riverstone Ownership	Non-Independent Directors	Independent Directors
50%	2	1
Between 20% and 50%	0	1
Less than 20%	0	0

Access Ownership	Non-Independent Directors	Independent Directors
At least 50%	1	0
Less than 50%	0	0

KNOC Ownership	Non-Independent Directors	Independent Directors
At least 50%	1	0
Less than 50%	0	0

A director that is designated by any Sponsor pursuant to the Stockholders Agreement may be removed and replaced at any time and for any reason (or for no reason) only at the direction and upon the approval of such Sponsor for so long as such Sponsor has the right to designate the applicable director. The replacement of any director will be designated by the Sponsor that designated any such vacant seat unless such Sponsor has lost its right to designate the applicable director pursuant to the above. If the Sponsor has lost its right to designate the applicable director and the Legacy Class A Stockholders hold at least 50% of our outstanding common stock, the Legacy Class A Stockholders will have the right to designate a replacement director by a vote of the Legacy Class A Stockholders holding a majority-in-interest of our outstanding common stock then held by the Legacy Class A Stockholders (each such director, a Replacement Director); provided, that such Replacement Director is independent of us, the Legacy Stockholders and their affiliates under the rules of the NYSE.

Composition of Board Committees

The Stockholders Agreement also provides that for so long as each Sponsor has the right to designate a director or an observer to the Board (as described below), we will cause any committee of our Board to include in its membership such number of members that are consistent with, and reflects, the right of each Sponsor to designate directors or observers to the Board, except to the extent that such membership would violate applicable securities laws or stock exchange or stock market rules. The members of any committee can exclude any board observer from any committee meeting to protect attorney-client privilege, in connection with a conflict of interest, or for any other reason with the consent of the Legacy Class A Stockholder that appointed the board observer, which consent cannot be unreasonably withheld, conditioned or delayed. In addition, for so long as the Negative Control Condition is satisfied, the delegation of power to a committee of the Board will be consistent with and will not circumvent the consent rights described under Consent Rights . The Board may not designate an executive committee.

Board Observers

The Stockholders Agreement provides certain Sponsors and Legacy Class A Stockholders with certain rights with respect to the designation of observers to the Board. Each observer generally may attend the meetings of our Board as an observer (and not as a director) and receive the same information given to directors of our Board. No observer has a vote on our Board. The members of the board can exclude any board observer from any board meeting to protect attorney-client privilege, in connection with a conflict of interest, or for any other reason with the consent of the Legacy Class A Stockholder that appointed the board observer, which consent cannot be unreasonably withheld, conditioned or delayed. The tables below state the number of board observers that each Sponsor (other than the Apollo Funds which have no such right) and other significant Legacy Class A Stockholders may designate pursuant to the Stockholders Agreement based on such Legacy Class A Stockholder s ownership of common stock, in each case, expressed as a percentage of its ownership of common stock as of the Effective Time (e.g., 50% means that the Legacy Class A Stockholder holds 50% of the common stock that it held as of the Effective Time).

Riverstone Ownership	**Board Observer**
Between 20% and 50%	2
Less than 20%	0

Access Ownership	**Board Observer**
Between 20% and 50%	1
Less than 20%	0

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KNOC Ownership	**Board Observer**
Between 20% and 50%	1
Less than 20%	0

EPE Management Investors, LLC	**Board Observer**
100%	2
Between 50% and 100%	1
Less than 50%	0

Other Significant Legacy Class A Stockholders	**Board Observer**
At least 50%	1
Less than 50%	0

Consent Rights

The Stockholders Agreement also provides that for so long as the Legacy Class A Stockholders hold at least 25% of our outstanding common stock and either the Apollo Funds or Riverstone is entitled to designate at least one director pursuant to the Stockholders Agreement (the Negative Control Condition), a majority of our Board, which majority includes (i) at least one director designated to our Board by the Apollo Funds and (ii) at least one director designated to our Board by one of the other Sponsors or one Replacement Director, must approve in advance certain of our significant business decisions, including each of the following (each such approval, a Special Board Approval):

- change the size or composition of our Board;
- any fundamental changes to the nature of our business as of the date of the Stockholders Agreement;
- our or any of our subsidiaries entry into any voluntary liquidation, dissolution or commencement of bankruptcy or insolvency proceedings, the adoption of a plan with respect to any of the foregoing or the decision not to oppose any similar proceeding commenced by a third party;
- the consummation of a change of control (including a drag-along sale);
- consummating any material acquisition or disposition by us of the assets or equity interests of any other entity involving consideration payable or receivable by us in excess of $100 million in the aggregate in any single transaction or series of transactions during any twelve-month period;

- any redemption, repurchase or other acquisition by us of our equity securities, other than (i) a redemption, repurchase or forfeiture of common stock or Class B common stock held by EMI and the Legacy Class B Stockholder, respectively, (ii) pursuant to a pro rata offer to all Legacy Stockholders or (iii) pursuant to the exercise of the right of first refusal, in each case, pursuant to the Stockholders Agreement;

- incurring any indebtedness by us (including through capital leases, the issuance of debt securities or the guarantee of indebtedness of another entity) in excess of $250 million or that would otherwise result in us having a leverage ratio of 2.5 to 1.0 or greater;

- hiring or firing our chief executive officer, our chief financial officer or any other member of senior management or approving the compensation arrangements of our chief executive officer, our chief financial officer or any other member of senior management (subject to the prior approval of the Compensation Committee of the Board), in accordance with all applicable governance rules;

- any payment or declaration of any dividend or other distribution on any of our equity securities or entering into a recapitalization transaction the primary purpose of which is to pay a dividend, other than intra-company dividends among us and our subsidiaries;

- approval of our annual budget;

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- any authorization, creation (by way of reclassification, merger, consolidation or otherwise) or issuance of any of our or our subsidiaries equity securities of any kind (other than any issuance of shares of Class B common stock to EPE Employee Holdings II or pursuant to any equity compensation plan of ours approved by the Compensation Committee, the issuance of equity of a subsidiary of ours to us or one of our wholly owned subsidiaries or a Class B Exchange), including any designation of the rights (including special voting rights) of one or more classes of our preferred stock;

- entry by us or any of our subsidiaries into any agreement that would restrict any Legacy Class A Stockholders (or any of their affiliates) from entering into or continuing to operate in any line of business or in any geographic area;

- changing any of our significant accounting policies, except as required by GAAP;

- settle, compromise or initiate any material litigation;

- any adoption, approval or issuance of any poison pill or similar rights plan or any amendment of such plan after the adoption thereof has received Special Board Approval;

- any amendment, modification or waiver of the Stockholders Agreement;

- any amendment, modification or waiver of our Second Amended and Restated Certificate of Incorporation or Amended and Restated Bylaws; and

- the creation by us of a non-wholly owned subsidiary, other than any non-wholly owned subsidiary that is an operating joint venture entered into by us in the ordinary course of business.

Amendment

The Stockholders Agreement may be amended by a Special Board Approval and the affirmative vote of the Legacy Class A Stockholders holding at least two-thirds of the shares of common stock held by the Legacy Class A Stockholders. Further, the Stockholders Agreement may not be amended in a manner that would disproportionally and materially adversely affect the interests of any Legacy Stockholder (in relation to any other Legacy Stockholder after taking into account the rights of such Legacy Stockholder) without the written approval of such Legacy Stockholder.

Other Provisions

The Stockholders Agreement further provides that each of the Legacy Stockholders will not vote to amend or modify any provision of our Second Amended and Restated Certificate of Incorporation or Amended and Restated Bylaws in a manner that would disproportionally and materially adversely affect the interests of any Legacy Stockholder (in relation to any other Legacy Stockholder after taking into account the rights of such Legacy Stockholder) without the written approval of such Legacy Stockholder. Further, the Stockholders Agreement provides that the Legacy Stockholders will vote and take all other necessary actions to ensure that the Second Amended and Restated Certificate of Incorporation or Amended and Restated Bylaws do not conflict with the Stockholders Agreement and to give effect to the provisions of the Stockholders Agreement. In addition, the Stockholders Agreement provides that we shall bear all of the costs and expenses associated with a Class B Exchange, including the costs and expenses incurred in connection with filing and maintaining a resale registration statement and brokerage commissions payable by holders of Class B common stock in connection with sales by such holders of shares of common stock received by such holders pursuant to a Class B Exchange.

Registration Rights Agreement

In connection with our Corporate Reorganization, we, the Sponsors and the other Legacy Class A Stockholders entered into a Registration Rights Agreement, dated as of August 30, 2013 (the Registration Rights Agreement). Pursuant to the Registration Rights Agreement, we have granted the Sponsors and the other Legacy Class A Stockholders the right, under certain circumstances and subject to certain restrictions, to require us to register under the Securities Act our common stock that are held or acquired by them.

Demand Rights. Specifically, the Registration Rights Agreement grants the Sponsors unlimited demand registration rights to request that we register all or part of their shares of common stock on Form S-3 under the Securities Act. We are not required to comply with any demand to file a registration statement on Form S-3 unless the aggregate gross cash proceeds reasonably expected to be received from the sale of securities requested to be included in the registration statement is at least $25 million (or such lower

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amount approved by the Board). The Registration Rights Agreement also grants Apollo five, and each other Sponsor two, demand registration rights to request that we register all or part of their shares of common stock on Form S-1 under the Securities Act. We are not required to comply with any demand to file a registration statement on Form S-1 unless the aggregate proceeds reasonably expected to be received from the sale of securities requested to be included in the registration statement is at least $100 million (or such lower amount approved by the Board).

Blackout Periods. We have the ability to delay the filing of a registration statement in connection with a demand request for not more than one period of 30 days in any twelve-month period, subject to certain conditions.

Piggyback Registration Rights. The Registration Rights Agreement also grants to the Legacy Class A Stockholders certain piggyback registration rights, which allow such holders the right to include certain securities in a registration statement filed by us, including in connection with the exercise of any demand registration rights by any other security holder possessing such rights, subject to certain customary exceptions.

Cut-Backs and Lock-up Periods. If the underwriter, in a demand or piggyback registration determines, in good faith, that the amount of common stock requested to be included in such offering exceeds the number or dollar amount that can be sold without adversely affecting such offering, then the underwriters will allocate the common stock to be included in such offering. The Legacy Class A Stockholders have agreed to enter into, if requested by underwriters, customary lock-up agreements in connection with an underwritten offering made pursuant to the Registration Rights Agreement. In connection with any underwritten offering, such period will start no earlier than 14 days prior to the expected pricing of such offering and will last no longer than 90 days after the date of the prospectus relating to such offering (extendable by not more than 34 days).

Underwriters. In connection with any underwritten offering pursuant to the Registration Rights Agreement, the underwriter will be selected: in the case of a demand registration, by the Legacy Class A Stockholders issuing the demand notice (subject to our approval, which will not be unreasonably withheld); and in all other cases (including a piggyback registration), by us.

Indemnification; Expenses. We have agreed to indemnify prospective sellers in an offering pursuant to the Registration Rights Agreement and certain related parties against any losses or damages arising out of or based upon any untrue statement or omission of material fact in any registration statement or prospectus pursuant to which such prospective seller sells shares of common stock, unless such liability arose out of or is based on such party s misstatement or omission. The Registration Rights Agreement also provides that we may require each prospective seller, jointly and not severally, as a condition to including any common stock in a registration statement filed in accordance with the Registration Rights Agreement, to agree to indemnify us against all losses caused by its misstatements or omissions up to the amount of net proceeds received by such prospective seller upon the sale of the common stock giving rise to such losses. We will pay all registration expenses incidental to our obligations under the Registration Rights Agreement, including legal fees and expenses, and the prospective seller will pay its portion of all underwriting discounts and commissions, if any, relating to the sale of its shares of common stock under the Registration Rights Agreement.

Except as described above, we shall not be required to pay (i) any fees and disbursements of any counsel retained by any Legacy Class A Stockholders or by any underwriter and (ii) any expenses incurred in connection with any offering of common stock at such time such common stock may be sold without limitation as to volume pursuant to Rule 144; provided, that we will pay such expenses in connection with a demand registration by any Sponsor on Form S-1, the first two demand registrations by each Legacy Class A Stockholder and any piggyback registration.

Amendment. The Registration Rights Agreement may be amended by a Special Board Approval and the affirmative vote of the Legacy Class A Stockholders holding at least two-thirds of the shares held by the Legacy Class A Stockholders. Further, the Registration Rights Agreement may not be amended in a manner that would disproportionally and materially adversely affect the interests of any Legacy Stockholder (in relation to any other Legacy Stockholder after taking into account the rights of such Legacy Stockholder) without the written approval of such Legacy Stockholder.

Amended and Restated Transaction Fee Agreement

In connection with the closing of the Acquisition, Apollo Global Securities, LLC, Riverstone V Everest Holdings, L.P. (together, the Initial Service Providers), Access and KNOC (collectively with the Initial Service Providers, the Service Providers) entered into a transaction fee agreement with EP Energy Global LLC, a wholly owned subsidiary of EPE Acquisition, LLC (EP Energy Global) and EPE Acquisition, LLC (the Initial Transaction Fee Agreement) relating to the provision of certain structuring services by the Service Providers to EPE Acquisition, LLC, its direct and indirect divisions and subsidiaries, parent entities or controlled affiliates (collectively, the Company Group) in connection with the closing of the Acquisition. In May 2012, EP Energy Global paid the Initial Service Providers a one-time transaction fee of $71.5 million in the aggregate in exchange for services rendered in connection with structuring the closing of the Acquisition, arranging the financing and performing other services in connection with the closing of the Acquisition. On December 20, 2013, the Initial Transaction Fee Agreement was amended and restated in its entirety (as so amended, the Amended and Restated Transaction Fee Agreement) by the Service Providers, EP Energy Global, EPE Acquisition, LLC and the Company, pursuant to which the requirement to pay an additional transaction fee to the Service Providers under the Initial Transaction Fee 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 the initial public offering.

Amended and Restated Management Fee Agreement

In connection with the closing of the Acquisition, Apollo Management VII, L.P., Apollo Commodities Management, L.P., with respect to Series I, Riverstone V Everest Holdings. L.P., Access and KNOC (collectively, the Management Service Providers) entered into a management fee agreement with EPE Acquisition, LLC and EP Energy Global (the Initial Management Fee Agreement) relating to the provision of certain management consulting and advisory services to the members of the Company Group following the consummation of the closing of the Acquisition. For 2013, we paid the Management Service Providers the annual fee of $25 million. Commencing in 2014, the management fee became payable in quarterly installments at the beginning of each calendar quarter. On December 20, 2013, the Initial Management Fee Agreement was amended and restated in its entirety (as so amended, the Amended and Restated Management Fee Agreement) by the Management Service Providers, EPE Acquisition, LLC, EP Energy Global and the Company, pursuant to which an additional fee became payable to the Management Service Providers in respect of management and similar services rendered prior to our initial public offering. Subject to the terms and conditions of the Amended and Restated Management Fee Agreement, upon the closing of the initial public offering in January 2014, we paid the Management Service Providers an additional transaction fee equal to approximately $83 million (the lesser of (i) 1% of the aggregate enterprise value paid or provided by the Company Group and (ii) $100,000,000). The Amended and Restated Management Fee Agreement requires such payment in connection with any transaction (including any merger, consolidation, recapitalization or sale of assets or equity interests) effected by a member of the Company Group after the consummation of the closing of the Acquisition and (x) which results in a change of control of the equity and voting securities, or sale of all or substantially all of the assets of, the Company Group, or (y) which is in connection with one or more public offerings of any class of equity securities of the Company, EPE Acquisition, LLC, EP Energy Global or any other member of the Company Group (including EP Energy). 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 initial public offering.

Supply Agreement

In November 2012, we entered into a two-year supply agreement with a subsidiary of Momentive Performance Materials Holdings LLC (Momentive) to provide certain fracturing materials for our Eagle Ford drilling operations. Momentive is an affiliate of Apollo, one of our Sponsors. During 2013, we made payments to Momentive in the amount of approximately $120 million pursuant to this contract. The supply agreement is a market-based, arm s length transaction.

Related Party Transactions Policy

Under the Stockholders Agreement, the consummation of any transaction involving us, on the one hand, and any Legacy Stockholder, director or affiliate of any Legacy Stockholder or director, on the other hand (each such transaction, a Related Party Transaction), will in each case require the approval of a majority of the directors, other than those directors that are (or whose affiliates are) party to such Related Party Transaction or have been designated by the Legacy Class A Stockholders who are party, or whose affiliates are party to, such Related Party Transaction. This approval is not required for (among other things): (i) any transaction that is consummated in the ordinary course of business, on arm s length terms and *de minimis* in nature (it being understood that any transaction or series of related transactions that involves goods, services, property or other consideration valued in excess of $10,000 will not be deemed to be *de minimis*); and (ii) an acquisition of additional securities by a Legacy Class A Stockholder pursuant to an exercise of its preemptive rights under the Stockholders Agreement.

Director Independence

We qualify as a controlled company under the NYSE rules, which eliminates the requirements that we have a majority of independent directors on our Board and that we have compensation and governance and nominating committees composed entirely of independent directors.

If at any time we cease to be a controlled company under applicable stock exchange rules, our Board will take all action necessary to comply with the applicable stock exchange rules, including appointing a majority of independent directors to our Board and establishing certain committees composed entirely of independent directors, subject to a permitted phase-in period. We will cease to qualify as a controlled company once our Sponsors, as a group, cease to control a majority of our voting stock.

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Our Board has determined Michael S. Helfer is independent as independence is defined in Rule 10A-3 of the Exchange Act and under the NYSE listing standards.

ITEM 14. ***PRINCIPAL ACCOUNTANT FEES AND SERVICES***

Ernst & Young LLP audited our financial statements for fiscal year 2013, including the audit of EP Energy Corporation and its subsidiaries. Included in the table below are the aggregate fees for professional services rendered to us by Ernst & Young LLP for the year ended December 31, 2013.

Principal Accountant Fees and Services

Aggregate fees for professional services rendered to us by Ernst & Young LLP for the years ended December 31 were (in thousands):

	2013	2012
Audit	$ 2,931	$ 2,982
Audit Related	180	2
Tax	202	160
Total	$ 3,313	$ 3,144

Audit Fees for the year ended December 31, 2013 were primarily for professional services rendered for the audit of consolidated financial statements of EP Energy Corporation and its subsidiaries; the review of documents filed with the SEC; consents; the issuance of comfort letters; and certain financial accounting and reporting consultations.

Audit Related Fees for the year ended December 31, 2013 were primarily for professional services and other advisory services rendered not included in Audit fees above.

Tax Fees for the year ended December 31, 2013 were for professional services related to tax compliance, tax planning and advisory services.

The audit committee of our board of directors has adopted a pre-approval policy for audit and non-audit services and the fees set forth above are consistent with such pre-approvals. The audit committee s current practice is to consider for pre-approval annually all categories of audit and permitted non-audit services proposed to be provided by our independent auditors for a fiscal year. Pre-approval of tax services requires the principal independent auditor provide the audit committee with written documentation of the scope and fee structure of the proposed tax services and discuss with the audit committee the potential effects, if any, of providing such services on the independent auditor s independence. The audit committee will also consider for pre-approval annually the maximum amount of fees and the manner in which the fees are determined for each type of pre-approved audit and non-audit services proposed to be provided by the independent auditors for the fiscal year. The audit committee must separately pre-approve any service that is not included in the approved list of services or any proposed services exceeding the pre-approved cost levels.

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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.

	Page
2. and (b). Exhibits	140

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.

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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 27th day of February 2014.

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 27, 2014
/s/ Dane E. Whitehead Dane E. Whitehead	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2014
/s/ Francis C. Olmsted III Francis C. Olmsted III	Vice President and Controller (Principal Accounting Officer)	February 27, 2014
/s/ Ralph Alexander Ralph Alexander	Director	February 27, 2014
/s/ Gregory A. Beard Gregory A. Beard	Director	February 27, 2014
/s/ Wilson B. Handler Wilson B. Handler	Director	February 27, 2014
/s/ John J. Hannan John J. Hannan	Director	February 27, 2014
/s/ Michael S. Helfer Michael S. Helfer	Director	February 27, 2014
/s/ Sam Oh Sam Oh	Director	February 27, 2014

/s/ Ilrae Park Ilrae Park	Director	February 27, 2014
/s/ Robert M. Tichio Robert M. Tichio	Director	February 27, 2014
/s/ Donald A. Wagner Donald A. Wagner	Director	February 27, 2014
/s/ Rakesh Wilson Rakesh Wilson	Director	February 27, 2014

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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 requested 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).
2.4	Purchase and Sale Agreement, dated as of June 9, 2013, by and among EP Energy E&P Company, L.P., EPE Nominee Corp. and Atlas Resource Partners, L.P. (Exhibit 2.1 to EP Energy LLC s Current Report on Form 8-K, filed with the SEC on June 13, 2013).
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).

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Exhibit No.	Exhibit Description
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 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).

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Exhibit No.	Exhibit Description
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	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).
10.10	Term Loan Agreement, dated as of April 24, 2012, by and among EP Energy LLC (f/k/a Everest Acquisition LLC), as Borrower, the Lenders party thereto, Citibank, N.A., as Administrative Agent and Collateral Agent, and Citigroup Global Markets Inc. and J.P. Morgan Securities LLC, as Co-Lead Arrangers (Exhibit 10.7 to EP Energy LLC s Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.11	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).
10.12	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).
10.13	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).
10.14	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).
10.15	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).
10.16	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).
10.17	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).
10.18	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).
10.19	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).

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Exhibit No.	Exhibit Description
10.20	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).
10.21	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).
10.22	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).
10.23	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).
10.24+	Employment Agreement dated May 24, 2012 for Clayton A. Carrell (Exhibit 10.18 to EP Energy LLC s Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.25+	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).
10.26+	Employment Agreement dated May 24, 2012 for Brent J. Smolik (Exhibit 10.20 to EP Energy LLC s Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.27+	Employment Agreement dated May 24, 2012 for Dane E. Whitehead (Exhibit 10.21 to EP Energy LLC s Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.28+	Employment Agreement dated May 24, 2012 for Marguerite N. Woung-Chapman (Exhibit 10.22 to EP Energy LLC s Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.29+	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).
10.30+	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).
10.31+	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).
10.32+	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).
10.33+	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).
10.34+	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).

Exhibit No.	Exhibit Description
10.35+	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).
10.36+	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).
10.37+	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).
10.38+	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).
10.39+*	Form of Notice Stock Option Grant and Stock Option Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan.
10.40+*	Form of Notice Restricted Stock Grant and Restricted Stock Award Agreement under EP Energy Corporation 2014 Omnibus Incentive Plan.
10.41	Stockholders Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto (Exhibit 10.39 to Amendment No. 1 to the Company s Registration Statement on Form S-1, filed with the SEC on October 11, 2013).
10.42	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).
10.43	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 PricewaterhouseCoopers, LLP, an independent registered public accounting firm.
23.3*	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, 2013.