EP Energy Corp
Form S-1
September 04, 2013

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As filed with the Securities and Exchange Commission on September 4, 2013

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM S-1

**REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933**

EP ENERGY CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**46-3472728**
(State or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

**1001 Louisiana Street
Houston, Texas 77002
713-997-1200**
(Address, including zip code, and telephone number, including area code, of registrants' principal executive offices)

**Marguerite N. Woung-Chapman
Senior Vice President, General Counsel and Corporate Secretary
EP Energy Corporation
1001 Louisiana Street
Houston, Texas 77002
713-997-1200**
(Name, address, including zip code, and telephone number, including area code, of agent for service)

With copies to:

Rosa A. Testani John Goodgame Akin Gump Strauss Hauer & Feld LLP One Bryant Park New York, NY 10036 212-872-8115	Gregory A. Ezring Paul, Weiss, Rifkind, Wharton & Garrison LLP 1285 Avenue of the Americas New York, NY 10019-6064 212-373-3458	Sean T. Wheeler Latham & Watkins LLP 811 Main Street, Suite 3700 Houston, TX 77002 713-546-7418

Approximate date of commencement of proposed sale of the securities to the public:
As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. o

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. o

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

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

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	**Proposed maximum aggregate offering price(1)**	**Amount of registration fee**
Class A Common Stock, $0.01 par value per share	$100,000,000	$13,640

(1) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(o) under the Securities Act of 1933, as amended.

The Registrant hereby amends this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrant shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933, as amended, or until this Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.

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Subject to completion, dated September 4, 2013

PRELIMINARY PROSPECTUS

Shares

EP Energy Corporation

Common Stock

$ per share

This is our initial public offering. We are selling shares of Class A common stock, $0.01 par value per share. All references to common stock herein refer to Class A common stock.

We expect the public offering price to be between $ and $ per share. Currently, no public market exists for our common stock. We intend to apply to list our common stock on the New York Stock Exchange under the symbol "EPE." Following the completion of this offering, we will remain a "controlled company" as defined under the NYSE listing rules because the group consisting of our Sponsors, which is comprised of affiliates of Apollo Global Management, LLC, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, will beneficially own % of our shares of outstanding common stock, assuming the underwriters do not exercise their option to purchase up to additional shares from us. See "Principal Stockholders."

Investing in our common stock involves risks that are described in the "Risk Factors" section beginning on page 19 of this prospectus.

	Price to Public	Underwriting Discounts and Commissions	Proceeds to EP Energy Corporation
Per Share	$	$	$
Total	$	$	$

We have granted the underwriters an option for a period of 30 days from the date of this prospectus to purchase up to an additional shares of our common stock at the initial public offering price less the underwriting discount.

Delivery of the shares of common stock will be made on or about , 2013.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The date of this prospectus is , 2013.

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You should rely only on the information contained in this prospectus. We have not authorized any person to provide you with any information or represent anything about us or this offering that is not contained in this prospectus. If given or made, any such other information or representation should not be relied upon as having been authorized by us. We are not making an offer in any jurisdiction where an offer or sale is not permitted. The information contained in this prospectus is current only as of its date.

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MARKET AND INDUSTRY DATA

This prospectus includes statements regarding factors that have impacted our and our customers' industries, such as our customers' access to capital. Such statements regarding our and our customers' industries and market share or position are statements of belief and are based on market share and industry data and forecasts that we have obtained from industry publications and surveys, as well as internal company sources. Industry publications, surveys and forecasts generally state that the information contained therein has been obtained from sources believed to be reliable, but there can be no assurance as to the accuracy or completeness of such information. Although we believe that the third party sources are reliable, we have not independently verified any of the data from third-party sources, nor have we ascertained the underlying economic assumptions relied upon therein. In addition, while we believe that the market share, market position and other industry information included herein is generally reliable, such information is inherently imprecise. While we are not aware of any misstatements regarding our industry data presented herein, our estimates involve risks and uncertainties and are subject to change based on various factors, including those discussed under "Risk Factors."

PRESENTATION OF RESERVES INFORMATION

The Securities and Exchange Commission (the "SEC") permits oil and gas companies, in their filings with the SEC, to disclose only estimated proved, probable and possible reserves that meet the SEC's definitions of such terms. We disclose estimated proved reserves in this prospectus. Our estimates of proved reserves contained in this prospectus were estimated by our internal staff of engineers and comply with the rules and definitions promulgated by the SEC. For the year ended December 31, 2012 and the six months ended June 30, 2013, we engaged Ryder Scott Company, L.P., an independent petroleum engineering consultant firm, to perform reserve audit services with respect to a substantial portion of our proved reserves.

EQUIVALENCY

This prospectus presents certain production and reserves-related information on an "equivalency" basis. 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. These conversions are based on energy equivalency conversion methods primarily applicable at the burner tip and do not represent value equivalencies at the wellhead. Although these conversion factors are industry accepted norms, they are not reflective of price or market value differentials between product types.

USE OF NON-GAAP FINANCIAL INFORMATION

In this prospectus, we use certain non-GAAP financial measures. We believe these supplemental measures provide meaningful information to our investors. Below are the non-GAAP measures used along with reference to where they are defined and reconciled with their comparable GAAP measures:

EBITDAX please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Supplemental Non-GAAP Measures;"

Adjusted EBITDAX please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Supplemental Non-GAAP Measures;"

Pro Forma Adjusted EBITDAX please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Supplemental Non-GAAP Measures;"

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Cash Operating Costs please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Cash Operating Costs and Adjusted Cash Operating Costs;"

Adjusted Cash Operating Costs please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Cash Operating Costs and Adjusted Cash Operating Costs;"

Reserve Replacement Ratio please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Reserve Replacement Ratio/Reserve Replacement Costs;"

Reserve Replacement Costs please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Reserve Replacement Ratio/Reserve Replacement Costs;" and

PV-10 please see "Summary Summary Operating and Reserve Information."

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SUMMARY

This summary highlights information appearing elsewhere in this prospectus. This summary is not complete and does not contain all of the information that may be important to you. You should carefully read the entire prospectus, including the information presented under "Risk Factors" and the pro forma and historical financial statements and related notes included elsewhere in this prospectus. Certain oil and gas industry terms used in this prospectus are defined in the "Glossary of Oil and Natural Gas Terms" beginning on page A-1 of this prospectus.

Except as otherwise indicated or unless the context otherwise requires, the terms "EP Energy," "we," "us," "our," "the Company" and "our company" refer to (i) EP Energy Corporation and its subsidiaries on a consolidated basis for periods following the completion of the Corporate Reorganization on August 30, 2013 and (ii) EPE Acquisition, LLC and its predecessor entities and their subsidiaries on a consolidated basis for periods prior to the Corporate Reorganization (including the operations of predecessor entities prior to the Acquisition (as defined below)).

Except as otherwise indicated, all of the information in this prospectus assumes (i) no exercise of the underwriters' option to purchase up to additional shares of common stock from us, (ii) an initial offering price of $ per share, the midpoint of the range set forth on the cover page of this prospectus, and (iii) a for one stock split will be effected as of the effective date of the registration statement of which this prospectus forms a part. The number of shares of common stock to be outstanding after completion of this offering is based on shares of our common stock to be sold by us in this offering and, except where indicated otherwise, does not give effect to shares of common stock reserved for future issuance under the Omnibus Incentive Plan (as defined in "Management Executive Compensation").

Estimates of our oil, natural gas and NGLs reserves, related future net cash flows and the present values thereof as of June 30, 2013 included in this prospectus were prepared by our internal staff of engineers and audited by the independent petroleum engineering firm of Ryder Scott Company, L.P. ("Ryder Scott").

Unless we indicate otherwise, all production, reserve and operating data in this prospectus give effect to our pending and recently completed divestitures described in " Recent Divestitures."

Our Company

We are an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. We are focused on creating shareholder value through the development of our low-risk drilling inventory located in four core areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), the Uinta Basin (Utah) and the Haynesville Shale (North Louisiana). In our core areas, we have identified in excess of 5,200 drilling locations, of which approximately 96% are oil wells. At current activity levels, this represents approximately 24 years of drilling inventory. As of June 30, 2013, we had proved reserves of 501 MMBoe (57% oil and 66% liquids) and for the three months ended June 30, 2013, we had average net daily production of 93,674 Boe/d (37% oil and 46% liquids).

Our management team has a proven track record of identifying, acquiring and developing unconventional oil and natural gas assets. The majority of our senior management team has worked together for over a decade and the team has significant experience at prominent oil and gas companies that have included El Paso Corporation, ConocoPhillips and Burlington Resources. We believe our management's experience in both acquiring resource-rich leasehold positions and efficiently developing those properties will enable us to generate attractive rates of return on our capital programs.

Each of our core areas is characterized by a favorable operating environment, long-lived reserve base and high drilling success rates. We have established significant contiguous leasehold positions in

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each area, representing approximately 450,000 net (620,000 gross) acres in total. Beginning in 2012, our capital programs have focused predominantly on the Eagle Ford Shale, the Wolfcamp Shale and the Uinta Basin, three of the premier unconventional oil plays in the United States, resulting in oil reserve and production growth of 47% and 88%, respectively, from December 31, 2011 to December 31, 2012. In July and August 2013, we divested non-core domestic natural gas assets for a total consideration of approximately $1.3 billion. Additionally, in July 2013, we entered into a Quota Purchase Agreement relating to the sale of our Brazil operations, which is expected to close by the end of the first quarter of 2014. As a result of this strategic repositioning, 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 in the future to this natural gas-weighted asset.

The following table provides a summary of oil, natural gas and NGLs reserve and production information for each of our areas of operation as of June 30, 2013. Our estimated proved reserves have been prepared by our internal reserve engineers and audited by Ryder Scott Company, L.P., our independent petroleum engineering consultants since 2004.

Estimated Proved Reserves

	Oil (MMBbls)	NGL (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Liquids (%)	Proved Developed (%)	PV-10(1) Value ($MM)	PV-10(1) % of Total (%)	Average Net Daily Production(2) (MBoe/d)	R/P (Years)(3)
Core Areas										
Eagle Ford Shale	167.7	27.3	217.4	231.2	84%	22%	4,084	55%	34.9	18.1
Wolfcamp Shale	43.4	8.6	58.3	61.7	84%	22%	711	10%	4.4	38.6
Uinta Basin	71.9		148.4	96.6	74%	35%	1,765	24%	11.4	23.2
Haynesville Shale			373.1	62.2	0%	69%	430	6%	29.0	5.9
Total Core Areas	**283.1**	**35.8**	**797.2**	**451.7**	**71%**	**31%**	**6,991**	**95%**	**79.7**	**15.5**
Other(4)	2.0	1.0	71.7	14.9	20%	83%	135	2%	5.3	7.7
Total Consolidated	**285.0**	**36.8**	**868.9**	**466.7**	**69%**	**33%**	**7,126**	**97%**	**85.0**	**15.0**
Four Star	2.1	6.2	155.9	34.3	24%	93%	260	3%	8.7	10.8
Total Combined	**287.2**	**43.0**	**1,024.8**	**501.0**	**66%**	**37%**	**7,386**	**100%**	**93.7**	**14.7**

(1) PV-10 is a non-GAAP measure and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. To determine PV-10 we used SEC pricing, including the unweighted arithmetic average of the historical first-day-of-the-month prices for the prior 12 months, which were $91.60 per barrel of oil and $3.44 per MMBtu of natural gas as of June 30, 2013. Please see " Summary Operating and Reserve Information."

(2) Represents daily production for the three months ended June 30, 2013.

(3) Calculated as total proved reserves divided by the annualized Average Net Daily Production for the three months ended June 30, 2013.

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

Operating Areas

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, having produced over 750 MMBoe since 2008, including approximately 348 MMBoe in 2012. 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), which results in some of the most prolific acreage in the area. 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. We currently have 97,689 net (105,416 gross) acres in the Eagle Ford, in which we have identified 983 drilling locations.

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For the three months ended June 30, 2013, our average net daily production was 34,944 Boe/d, representing growth of 115% over the same period in 2012. As of June 30, 2013, we had five rigs running and plan to drill 126 wells in 2013 (of which 67 have been drilled through June 30, 2013), representing 58% of our total wells planned in 2013. For the six months ended June 30, 2013 our average cost per well was $7.5 million, representing an 11% decline from our average cost per well for the same period in 2012. We expect our average cost per well to continue to decline.

Wolfcamp Shale. The Wolfcamp Shale is located in the Permian Basin, which has produced more than 29 billion barrels of oil and 75 Tcf of gas over the past 90 years and is estimated by industry experts to contain remaining recoverable oil and natural gas reserves exceeding what has already been produced. With oil production of over 880 MBbls/d from over 80,000 wells during the six months ended June 30, 2013, the Permian Basin represented 51% of the crude oil produced in the State of Texas and approximately 17% of the crude oil and condensate produced onshore in the lower 48 United States. The basin is characterized by numerous, stacked oil reservoirs that provide excellent targets for horizontal drilling. We are currently targeting the Wolfcamp Shale in the Southern Midland Basin, where industry horizontal drilling has added over 50 MBoe/d to the basin's production since 2010.

In 2009 and 2010, we leased 138,130 net (138,468 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. Following our drilling results in 2012, we moved forward to full development of the Wolfcamp B, and began delineation of the Wolfcamp C. Our initial 30-day oil equivalent production rates are up to 600 Boe/d for the Wolfcamp B. As of June 30, 2013, we have identified 2,938 drilling locations in the Wolfcamp A, the Wolfcamp B and the Wolfcamp C across our acreage.

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.

For the three months ended June 30, 2013, our average net daily production was 4,382 Boe/d, representing growth of 152% over the same period in 2012. As of June 30, 2013, we had three rigs running and plan to drill 65 wells in 2013 (of which 25 have been drilled through June 30, 2013), representing 30% of our total wells planned in 2013. For the six months ended June 30, 2013 our average cost per well was $5.9 million, representing a 24% decline from our average cost per well for the same period in 2012. Similar to the Eagle Ford Shale, we expect our average cost per well to continue to decline.

Uinta Basin. The Uinta Basin, located in northeastern Utah, has produced 577 MMbbls since its discovery in 1949 and is characterized by naturally fractured, tight oil sands with multiple zones. Our operations are primarily focused on developing the Altamont Field (including the Bluebell and Cedar Rim fields), which is the largest field in the basin. We own 172,293 net (318,568 gross) acres in Duchesne and Uinta Counties, making us the largest lease owner in the Altamont Field. Since their discovery, the Altamont, Bluebell and Cedar Rim fields have produced a combined total of over 300 MMBbls from the oil-rich Wasatch and Green River sandstones. With gross thicknesses over 4,300 feet across multiple sandstone and carbonate intervals, 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 900 Boe/d. Our current activity is mainly focused on the development of our vertical inventory on 160-acre spacing. We have identified an inventory of 1,104 drilling locations (758 vertical and 346 horizontal). The industry is currently piloting 80-acre vertical downspacing programs in

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the Wasatch and Green River formations and horizontal development programs in the multiple shale 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.

For the three months ended June 30, 2013, our average net daily production was 11,433 Boe/d, representing growth of 14% over the same period in 2012. As of June 30, 2013, we had two rigs running and plan to drill 26 wells in 2013 (of which 13 have been drilled through June 30, 2013), representing 12% of our total wells planned in 2013. For the six months ended June 30, 2013 our average cost per well was $5.2 million, representing a 13% decline from our average cost per well for the same period in 2012.

Haynesville Shale. In addition to our key 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. This area is within the core of the Haynesville Shale with net thickness of 114 feet (210 feet gross), resulting in initial 30-day gas equivalent production rates up to 18 MMcfe/d. We currently have 40,029 net (59,210 gross) acres in this area. As of June 30, 2013, we have identified 190 drilling locations.

For the three months ended June 30, 2013, our average net daily production was 174 MMcfe/d. As of June 30, 2013, we had 191 producing wells, which provide cash flow to fund the development of our core oil programs. We do not plan to drill any new wells in the Haynesville in 2013. 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 June 30, 2013:

Core Acreage and Inventory Summary as of June 30, 2013(1)

	Acres		Drilling Locations (#)	2013 Drilling Locations(2) (#)	2010 - 2013 Drilling Success Rate	Inventory Life (Years)(3)
	Gross	Net				
Core Areas						
Eagle Ford Shale	105,416	97,689	983	126	100%	7.8
Wolfcamp Shale	138,468	138,130	2,938	65	93%	45.2
Uinta Basin	318,568	172,293	1,104	26	100%	42.5
Haynesville Shale	59,210	40,029	190		100%	NA
Total Core Areas	**621,662**	**448,141**	**5,215**	**217**	**99%**	**24.0**

(1) For more information regarding our acreage and inventory data, see "Business Our Properties and Core Areas."

(2) Represents gross operated wells to be completed in 2013.

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

Other

In addition to our core areas, we have other producing assets that contribute cash flow toward the development of our oil-focused core areas. These assets are comprised of our South Louisiana Wilcox assets, located primarily in Beauregard Parish, Louisiana, and our Arklatex Tight Gas assets located in Northern Louisiana that produce from reservoirs such as Travis Peak, Hosston, and Cotton Valley.

We also have an approximate 49% equity interest in Four Star Oil & Gas Company ("Four Star"), an unconsolidated entity that operates primarily in the San Juan, Permian, Hugoton and South Alabama basins.

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Business Strategy

We are a high-growth, 100% onshore U.S., oil-weighted company with a large inventory of high-return, low-risk drilling locations. We are focused on creating shareholder value by implementing the following strategies:

Grow Oil Production, Cash Flow and Reserves through the Development of our Extensive Drilling Inventory

We have assembled a drilling inventory of over 5,200 drilling locations across approximately 450,000 net (620,000 gross) acres in the Eagle Ford Shale, the Wolfcamp Shale, the Uinta Basin and the Haynesville Shale. The concentration and scale of our core leasehold positions, coupled with our technical understanding of the reservoirs, should allow us to efficiently develop our core areas and allocate capital to maximize the value of our resource base. In 2012, we invested $1.5 billion (92% in our core oil areas) of capital expenditures and grew oil production by 11,511 Bbls/d, or 88%, from an average of 13,042 Bbls/d in 2011 to an average of 24,553 Bbls/d in 2012. Pro Forma Adjusted EBITDAX increased by 46% from 2011 to 2012. We also increased proved oil reserves by 82 MMBbls, or 47%, from 175 MMBbls at December 31, 2011 to 257 MMBbls at December 31, 2012. In 2013, we plan to invest approximately $1.9 billion of capital expenditures, of which 95% is dedicated to developing our core oil areas. For the six months ended June 30, 2013, our capital expenditures were $937 million. We believe that our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, cash flow and reserve growth and create shareholder value. We consider our inventory of drilling locations to be low risk because they are in areas where we (and other producers) have extensive drilling and production experience and success. For additional information regarding Adjusted EBITDAX, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Supplemental Non-GAAP Measures."

Maintain an Extensive Low-Risk Drilling Inventory

We have a demonstrated track record of identifying and cost effectively acquiring low-risk resource development opportunities. We follow a geologically driven strategy to establish large, contiguous leasehold positions in the core of prolific basins and opportunistically add to those positions through bolt-on acquisitions over time. We were an early entrant into the Eagle Ford and Wolfcamp Shales through grassroots leasing efforts, amassing average positions of over 100,000 net acres, and we methodically expanded our position in the Uinta Basin through targeted acquisitions. We will continue to identify and opportunistically acquire additional acreage and producing assets to add to our multi-year drilling inventory.

Enhance Returns by Continuously Improving Capital and Operating Efficiencies

We maintain a disciplined, returns-focused approach to capital allocation. Our large and diverse portfolio of drilling locations allows us to conduct cost-efficient operations and allocate capital to our highest-margin assets in a variety of commodity price environments. We continuously monitor and adjust our development program in order to maximize the value of our extensive portfolio of drilling opportunities. In each of our core areas, we have realized improvements in EURs while delivering reductions in drilling and completion costs since 2011. We have reduced our average cost per well in the Wolfcamp by 40%, Eagle Ford by 24% and Uinta Basin by 22% from 2011 through the first half of 2013. These cost reductions have been due to many improvements, including substantial reductions in cycle times and successful negotiations for supplies and services. We expect further cost reductions going forward due to additional learning and efficiencies, including drilling wells from common pad sites, shared use of pre-existing central facilities and other economies of scale.

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Identify and Develop Additional Drilling Opportunities in our Portfolio

Our existing asset base provides numerous opportunities for our highly experienced technical team to create shareholder value by increasing our inventory beyond our currently identified drilling locations. In the Permian Basin, we have evaluated multiple Wolfcamp horizons, and we are currently running pilot delineation programs in the Wolfcamp A and C horizons. Additionally, this acreage is prospective for the Cline Shale, the Spraberry and other stacked formations. The Uinta Basin has a significant inventory of low-risk, vertical infill drilling locations and is also currently being assessed for additional horizontal development potential in multiple shale and tight sands intervals. Our primary focus in the Eagle Ford Shale is increasing incremental returns through a reduction in drilling and completion costs. Our 3-D seismic programs in the Uinta and Permian Basins should further enhance our ability to increase the number of and high grade our drilling locations.

Maintain Liquidity and Financial Flexibility

We intend to fund our organic growth predominantly with internally generated cash flows while maintaining ample liquidity. We will continue to maintain a disciplined approach to spending whereby we allocate capital in order to optimize returns and create shareholder value. Upon completion of this offering, we will have $2.5 billion available for borrowing under our reserve-based revolving credit facility (the "RBL Facility"). As we pursue our strategy of developing high-return opportunities in our core areas, we expect our cash flow and borrowing base to grow, thereby further enhancing our liquidity and financial strength. We protect these future cash flows and liquidity levels by maintaining a three year rolling hedge program. In general, we target hedging levels of over 50% of expected production on a rolling three year basis.

Competitive Strengths

We believe the following strengths provide us with significant competitive advantages:

Large, Concentrated Operated Positions in the Core Areas of Prolific Oil Resource Plays

We own and operate contiguous leasehold positions in the core areas of three of the premier North American oil resource plays: the Eagle Ford Shale, the Wolfcamp Shale and the Uinta Basin. We have approximately 410,000 net (560,000 gross) acres across these three plays that we have substantially de-risked through our ongoing drilling programs. Since 2010, we have drilled and completed 338 wells across these three plays with a success rate of approximately 99%. Based on our analysis of subsurface data and the production history of our wells and those of offset operators, we have confirmed high quality reservoir characteristics across a broad aerial extent with significant hydrocarbon resources in place. Based upon our well costs and production rates, we believe our core oil areas offer some of the best single well rates of return of all North American resource plays.

Multi-Year Inventory of Low-Risk Drilling Opportunities

Our 5,215 low-risk drilling locations across our core areas as of June 30, 2013 provide us with approximately 24 years of drilling inventory, of which 96% are oil wells. We have used the subsurface data from our development programs to identify and prioritize our inventory. These drilling locations are included in our inventory after they have passed through a rigorous technical evaluation. In addition to our 5,215 identified drilling locations, we believe we have the potential to increase our multi-year drilling inventory with horizontal drilling locations in the Cline Shale and vertical drilling locations in the Spraberry and other stacked formations in the Permian Basin and vertical infill and horizontal drilling locations in the Wasatch and Green River formations in the Uinta Basin. Our ongoing technical assessment and development activities provide the potential for identification of additional drilling opportunities on our properties.

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High-Quality Proved Reserve Base with Substantial Current Production

Our leasehold position and inventory of low-risk drilling locations is complemented by a substantial proved reserve base. As of June 30, 2013, we had proved reserves of 501 MMBoe (57% oil and 66% liquids) with a PV-10 of $7.4 billion (86% oil and 91% liquids). For the three months ended June 30, 2013, our average net daily production was 93,674 Boe/d, which was 37% oil and 46% liquids. Our current production provides a stable source of cash flow to fund the development of our core programs. This significantly reduces our reliance on outside sources of capital. In addition, our extensive inventory improves our ability to replace and grow proved reserves.

Significant Operational Control with Low Cost Operations

Our significant operational control permits us to efficiently manage the amount and timing of our capital outflows, allowing us to continually improve our drilling and operating practices. We operate over 83% of our producing wells and have operational control of approximately 95% of our core area drilling inventory as of June 30, 2013. We employ a centralized operational structure to accelerate our internal knowledge transfer between our drilling and completion programs and to continually enhance our field operations and base production performance. We have decreased our average cost per well by 24%, 11% and 13% in the Wolfcamp Shale, Eagle Ford Shale and Uinta Basin, respectively, for the six months ended June 30, 2013, compared to our average cost per well for the same period in 2012.

Capital Allocation Flexibility and Scale across Multiple Basins

Our existing assets are geographically diversified among many of the major basins of North America, which helps to insulate us from regional commodity pricing and cost dislocations that occur from time to time. While our existing producing assets are well diversified, they are also of a critical mass (on average over 100,000 net acres in each core area), which enables us to drive efficiencies and benefit from economies of scale across multiple basins. Furthermore, because of our centralized operational structure, we are able to quickly transfer operational efficiencies from one project to the next. From January 1, 2008 to June 30, 2013, we have drilled 386 horizontal shale wells. From this deep operational knowledge base and sizeable, concentrated positions in multiple basins, we have the flexibility to allocate significant amounts of capital across our properties in an efficient and value-maximizing manner.

Ability to Direct Capital to the Prolific Haynesville Shale

The Haynesville Shale is a key asset for us and is likely to compete for development capital if natural gas prices improve. Because our operations are surrounded by existing infrastructure, future returns are primarily driven by drilling and completion costs and natural gas prices. Since our Haynesville wells have demonstrated high initial production rates and strong EURs, small movements in natural gas prices can drive significant incremental value creation. Since these leases are held-by-production, we have the ability to redirect capital to this prolific asset in the future.

Significant Liquidity and Financial Flexibility

Upon completion of this offering, we will have $2.5 billion available for borrowing under our RBL Facility. We maintain a robust hedging program in order to protect our cash flows through commodity cycles. As of August 2, 2013, our hedged volumes for 2013, 2014, 2015 and 2016 represent 89%, 83%, 61% and 6%, respectively, based on our total equivalent production for the three months ended June 30, 2013. After the completion of this offering, we expect that liquidity provided by operating cash flow, availability under the RBL Facility and available cash will give us the financial flexibility to pursue our planned capital expenditures for the foreseeable future.

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Experienced Management Team with Proven Track Record

With an average of 24 years of experience, our senior management team has a strong track record built at El Paso Corporation and in former leadership roles with Burlington Resources, ConocoPhillips and other leading energy companies. The majority of our senior management team has worked together for over a decade and has significant experience in identifying, acquiring and developing unconventional oil and natural gas assets, including experience in horizontal drilling and developing shales. Through a combination of invested equity and incentive programs, we believe our management is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

2013 Capital Budget

We have a projected 2013 capital program of approximately $1.9 billion. Our capital program will remain focused on continuing to grow production, cash flows, and reserves in our highest return oil programs. In particular, the Eagle Ford Shale currently generates the highest returns in our portfolio and, as a result we are investing the majority of our capital in this program. We expect that liquidity provided by operating cash flow, availability under the RBL Facility and available cash will be sufficient to fund the 2013 capital plan.

	2013 Capital Program						Six months ended June 30, 2013	
($ in Millions)	Drilling & Completion	Facilities & Other	Total	% of Total	Active Rigs(2)	2013 Drilling Locations(3)	Capital Expenditures	Gross Wells Drilled
Core Areas								
Eagle Ford Shale	$ 897	$ 221	$ 1,118	58%	5	126	$ 600	67
Wolfcamp Shale	447	54	501	26%	3	65	236	25
Uinta Basin	137	58	195	10%	2	26	94	13
Haynesville Shale		1	1	0%			1	
Total Core Areas	**$ 1,481**	**$ 334**	**$ 1,815**	**95%**	**10**	**217**	**$ 931**	**105**
Other(1)	14	85	99	5%		1	6	
Total	**$ 1,495**	**$ 419**	**$ 1,914**	**100%**	**10**	**218**	**$ 937**	**105**

(1) Consists of South Louisiana Wilcox, Arklatex Tight Gas and approximately $70 million of capitalized general and administrative, interest and other costs.

(2) Active Rigs as of June 30, 2013.

(3) Represents gross operated wells to be completed in 2013.

In the beginning of the year, we projected a 2013 capital program of approximately $1.7 billion. Based on the results of the first half of the year and the results of our asset divestitures, we increased our 2013 capital program by up to $175 million for incremental drilling and completion activity. This incremental capital has added 36 wells to the original budget of 182 wells to be completed this year.

Recent Divestitures

During the third quarter of 2013, we sold certain of our natural gas properties, including our CBM properties (Raton, Arkoma and Black Warrior Basin), the majority of our Arklatex natural gas properties and our natural gas properties in South Texas. The total consideration from these transactions was approximately $1.3 billion, and proceeds were used to repay outstanding borrowings under the RBL Facility and to fund capital expenditures.

Additionally, in July 2013, certain of our subsidiaries entered into a Quota Purchase Agreement relating to the sale of all of our Brazil operations. Pursuant to the Quota Purchase Agreement, the subsidiaries have agreed to sell all of our equity interests in two Brazilian subsidiaries to a third party. The transaction is expected to close by the end of the first quarter of 2014, subject to Brazilian regulatory approval and certain other customary closing conditions.

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As a result of these pending and completed divestitures, we are a higher-growth, 100% onshore U.S., oil-weighted company with a large inventory of high-return, low-risk drilling locations.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile commodity prices and other material factors. For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, please read "Risk Factors" and "Cautionary Note Regarding Forward-Looking Statements."

Corporate History and Structure

EP Energy Corporation, which was incorporated on August 8, 2013, is a holding company, and its sole asset is its direct and indirect ownership of EPE Acquisition, LLC ("EPE Acquisition") and EPE Acquisition's subsidiaries. On May 24, 2012, EPE Acquisition indirectly acquired all of the equity interests in various entities that collectively owned all of El Paso Corporation's exploration and production assets (the "Acquisition").

Prior to our corporate reorganization (the "Corporate Reorganization") on August 30, 2013, affiliates of Apollo Global Management, LLC, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation (collectively, the "Sponsors"), other co-investors, members of our management team and certain of our employees directly and indirectly owned all of the Class A membership units and Class B membership units in EPE Acquisition. Class A membership units represented full value or capital interests and Class B membership units represented profits interests. Members of our management and certain employees held their Class B membership units through EPE Employee Holdings, LLC.

As part of our Corporate Reorganization, through a series of contributions (i) all of the Class A membership units in EPE Acquisition were directly or indirectly exchanged for shares of common stock of EP Energy Corporation, which have substantially the same interests, rights and obligations as the Class A membership units and (ii) all of the Class B membership units in EPE Acquisition were exchanged for shares of Class B common stock of EP Energy Corporation, which have substantially the same interests, rights and obligations as the Class B membership units. We refer to (i) these direct and indirect holders of 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." Please read "Corporate Reorganization."

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The diagram below sets forth a simplified version of our organizational structure after giving effect to the Corporate Reorganization, our pending and completed divestitures and this offering. The diagram is provided for illustrative purposes only and does not represent all legal entities affiliated with us.

(1) The Sponsors, the public stockholders and management will hold %, % and % of shares of common stock, respectively, if the underwriters exercise in full their option to purchase additional shares.

(2) See "Description of Certain Indebtedness."

(3) Co-Issuer of EP Energy LLC's senior secured notes and senior notes.

(4) Guarantors of RBL Facility, senior secured term loans, senior secured notes and senior notes.

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Our Sponsors

Apollo Global Management, LLC (together with its subsidiaries, "Apollo"), founded in 1990, is a leading global alternative investment manager with offices in New York, Los Angeles, Houston, London, Frankfurt, Luxembourg, Singapore, Mumbai and Hong Kong. As of June 30, 2013, Apollo had assets under management of approximately $113 billion in private equity, credit and real estate funds invested across a core group of nine industries, including natural resources, where Apollo has considerable knowledge and resources. Apollo's team of more than 250 seasoned investment professionals possesses a broad range of transactional, financial, managerial and investment skills, which has enabled the firm to deliver strong long-term investment performance throughout expansionary and recessionary economic cycles.

Riverstone Holdings LLC (together with its affiliates, "Riverstone"), founded in 2000, is an energy and power-focused private equity firm with approximately $25 billion of equity capital raised across seven investment funds and co-investments. Riverstone conducts buyout and growth capital investments in the midstream, exploration & production, oilfield services, power and renewable sectors of the energy industry. With offices in New York, London and Houston, the firm has committed approximately $23.7 billion to 102 investments in North America, Latin America, Europe, Africa and Asia.

Access Industries ("Access") is a privately held, U.S.-based industrial group with long-term holdings worldwide. Founded by industrialist Len Blavatnik, Access' focus spans three key sectors: natural resources and chemicals; telecommunications and media; and real estate. Access has offices in New York, London and Moscow.

Korea National Oil Corporation ("KNOC") was incorporated in 1979 to engage in the development of oil fields, distribution of crude oil, maintenance of petroleum reserve stock and improvement of the petroleum distribution structure under the Korea National Oil Corporation Act. KNOC is wholly owned by the Korean government and located in Anyang, Gyeonggi-do in Korea. KNOC also has nine petroleum stockpile offices, one domestic gas field management office, 13 overseas offices in Vietnam and other countries and numerous overseas subsidiaries and affiliates in the United States and other countries.

Corporate Information

Our principal executive offices are located at 1001 Louisiana Street, Houston, Texas 77002. Our telephone number is (713) 997-1000. Our website address is www.epenergy.com. We expect to make available our periodic reports and other information filed with or furnished to the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

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The Offering

Issuer	EP Energy Corporation
Common stock offered by us	shares
Common stock to be outstanding immediately after the offering	shares
Class B common stock to be outstanding immediately after the offering	shares (see "Description of Capital Stock Class B common stock").
Underwriters' option to purchase additional shares of common stock in this offering	We have granted to the underwriters a 30-day option to purchase up to additional shares at the initial public offering price less underwriting discounts and commissions.
Common stock voting rights	Each share of our common stock will entitle its holder to one vote.
Dividend policy	We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends will be made by our board of directors (our "Board") in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements and other contracts, including requirements under the Stockholders Agreement described elsewhere in this prospectus, and other factors our Board deems relevant. See "Dividend Policy."
Use of proceeds	We estimate that our net proceeds from this offering will be approximately $ million after deducting the estimated underwriting discounts and commissions and other expenses of $ million payable by us, assuming the shares are offered at $ per share, which represents the midpoint of the range set forth on the front cover of this prospectus. We intend to use the net proceeds (i) to redeem all of the outstanding 8.125%/8.875% Senior PIK Toggle Notes due 2017 issued by our subsidiaries, EPE Holdings LLC and EP Energy Bondco Inc., and pay the redemption premium and the accrued and unpaid interest on those notes, (ii) to repay outstanding borrowings under the RBL Facility, (iii) to pay an approximately $ million fee under the transaction fee agreement with certain affiliates of our Sponsors and (iv) for general corporate purposes. See "Use of Proceeds."
Listing	We intend to list our common stock on the New York Stock Exchange ("NYSE") under the trading symbol "EPE."
Risk factors	You should carefully read and consider the information set forth under "Risk Factors" beginning on page 19 of this prospectus and all other information set forth in this prospectus before deciding to invest in our common stock.

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Summary Historical and Pro Forma Consolidated Financial Data

Set forth below is the summary historical consolidated financial data for the periods and as of the dates indicated for EPE Acquisition, LLC, the ultimate holding company prior to our Corporate Reorganization. Historical financial results of EPE Acquisition, LLC in this prospectus for the period before the Acquisition on May 24, 2012 are referred to as those of the predecessor and after the Acquisition are referred to as those of the successor in accordance with the required GAAP presentation. See "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and related notes appearing elsewhere in this prospectus.

We have derived the summary historical consolidated balance sheet data as of December 31, 2012 (successor) and December 31, 2011 (predecessor), and the statements of income data and statements of cash flow data for the period from February 14, 2012 (inception) to December 31, 2012 (successor), the period from January 1, 2012 through May 24, 2012 (predecessor) and each of the two years in the period ended December 31, 2011 (predecessor), from the audited consolidated financial statements of EPE Acquisition, LLC appearing elsewhere in this prospectus. We have derived the summary historical consolidated balance sheet data as of December 31, 2010 from the audited consolidated financial statements not included herein of EP Energy Corporation, the predecessor of EPE Acquisition, LLC and referred to herein as Historical EP Energy Corporation. The summary unaudited historical consolidated financial data as of and for the six months ended June 30, 2013 have been derived from the unaudited consolidated financial statements of EPE Acquisition, LLC appearing elsewhere in this prospectus, which have been prepared on a basis consistent with the audited consolidated financial statements of EPE Acquisition, LLC. In the opinion of management, such unaudited financial data reflects all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of the results for such period. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year or any future period.

The table below also includes EP Energy Corporation's (issuer) unaudited pro forma condensed consolidated statement of income data, giving pro forma effect to the pending and recently completed divestitures, certain debt repayments, a distribution, the Corporate Reorganization, certain other adjustments in connection with the Acquisition and this offering, all as if they had occurred on January 1, 2012. The unaudited pro forma condensed consolidated balance sheet has been prepared as if these transactions had occurred on June 30, 2013. The pro forma adjustments are based upon available information and certain assumptions that we believe are reasonable. The summary unaudited pro forma condensed consolidated financial data are based upon available information and certain assumptions that management believes are factually supportable and that are reasonable under the circumstance. The pro forma financial data is provided for informational purposes only and do not purport to represent what our results of operations or financial position actually would have been if these transactions had occurred at any other date, and such data does not purport to project our results of operations for any future period.

The following summary historical and pro forma financial data should be read in conjunction with the information included under the headings " Recent Divestitures," " Corporate History and Structure," " The Offering," "Selected Historical Consolidated Financial Data," "Use of Proceeds," "Capitalization" and "Management's Discussion and Analysis of Financial Condition and Results of

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Operations" and the historical and pro forma consolidated financial statements and related notes included elsewhere in this prospectus.

	EP Energy Corporation Pro Forma		EPE Acquisition, LLC Historical				
	Six months ended June 30, 2013	Year ended December 31, 2012	Six months ended June 30, (Successor) 2013	February 14 (inception) to December 31, (Successor) 2012	January 1 to May 24, (Predecessor) 2012	Year ended December 31, (Predecessor) 2011	2010
	(unaudited)		(unaudited)				
			(in millions)				
Statement of income data							
Operating revenues:							
Oil and condensate	$	$	$ 568	$ 555	$ 322	$ 552	$ 346
Natural gas			215	278	262	973	974
NGL			32	32	29	57	60
Physical sales			815	865	613	1,582	1,380
Financial derivatives(1)			35	(62)	365	284	390
Other						1	19
Total operating revenues			850	803	978	1,867	1,789
Operating expenses:							
Natural gas purchases			10	19			
Transportation costs			46	51	45	85	73
Lease operating expenses			98	96	96	217	193
General and administrative expenses			118	371	75	201	190
Depreciation, depletion and amortization			277	217	319	612	477
Impairments/Ceiling test charges			10	1	62	158	25
Exploration expense			27	50			
Taxes, other than income taxes			43	51	45	91	85
Other							15
Total operating expenses			629	856	642	1,364	1,058
Operating income (loss)			221	(53)	336	503	731
Income (loss) from unconsolidated affiliate(2)			6	(1)	(5)	(7)	(7)
Other income (expense)			(1)	3	(3)	(2)	3
Loss on extinguishment of debt			(3)	(14)			
Interest expense, net of capitalized interest			(178)	(219)	(14)	(12)	(21)
Income (loss) from continuing operations before income taxes			45	(284)	314	482	706
Income tax expense			2	2	136	220	263
Income (loss) from continuing operations			43	$ (286)	$ 178	$ 262	$ 443
Income from discontinued operations			44	30			
Net income (loss)	$	$	$ 87	$ (256)	$ 178	$ 262	$ 443
Net income (loss) per common share Basic and Diluted							

Weighted Average common shares Outstanding Basic and Diluted							
Statement of cash flows data							
Net cash provided by (used in):							
Operating activities			$ 450	$ 449	$ 580	$ 1,426	$ 1,067
Investing activities			(906)	(7,893)	(628)	(1,237)	(1,130)
Financing activities			670	7,513	110	(238)	(46)
Other financial data							
Capital expenditures(3)	$	$	$ 937	$ 941	$ 619	$ 1,644	$ 1,318
Adjusted EBITDAX(4)			574	782	533	1,391	1,205
Pro forma Adjusted EBITDAX(4)			563	751	458	832	505

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	Pro Forma		Historical			
	EP Energy Corporation		EPE Acquisition, LLC			Historical EP Energy Corporation
	As of June 30, 2013	As of December 31, 2012	As of June 30, (Successor) 2013	As of December 31, (Successor) 2012	As of December 31, (Predecessor) 2011	As of December 31, (Predecessor) 2010
	(in millions)					
Balance sheet data						
Cash and cash equivalents	$		$ 283	$ 69	$ 25	$ 74
Total assets			9,181	8,306	5,099	4,942
Total debt			5,392	4,695	851	301
Members'/stockholders' equity			2,842	2,748	3,100	3,067

(1) Includes $5 million, $11 million and $11 million for the period from January 1 to May 24, 2012 and the years ended December 31, 2011 and 2010, respectively, reclassified from accumulated other comprehensive income associated with accounting hedges. No amount was reclassified for the period from February 14 (inception) to December 31, 2012 or thereafter.

(2) Includes equity earnings from Four Star, our unconsolidated affiliate, net of amortization of the excess of our investment in Four Star over the underlying equity in its net assets.

(3) Represent accrual based capital expenditures including acquisitions capital, and excludes asset retirement obligations.

(4) Adjusted EBITDAX and Pro Forma Adjusted EBITDAX are non-GAAP measures and are not measurements of operating performance computed in accordance with GAAP and should not be considered as substitutes for operating income, income (loss) from continuing operations, net income or cash flows from operating activities computed in accordance with GAAP. These measures may not be comparable to similarly titled measures of other companies. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Supplemental Non-GAAP Measures."

The following table provides an unaudited reconciliation of income (loss) from continuing operations to Adjusted EBITDAX and Pro Forma Adjusted EBITDAX:

	EP Energy Corporation Pro Forma		EPE Acquisition, LLC Historical				
	Six months ended June 30, 2013	Year ended December 31, 2012	Six months ended June 30, (Successor) 2013	February 14 (inception) to December 31, (Successor) 2012	January 1 to May 24, (Predecessor) 2012	Years ended December 31, (Predecessor) 2011	2010
				(in millions)			
Income (loss) from continuing operations	$	$	43	$ (286)	$ 178	$ 262	$ 443
Income tax expense			2	2	136	220	263
Interest expense, net of capitalized interest			178	219	14	12	21
Depreciation, depletion and amortization			277	217	319	612	477
Exploration expense			27	50			
EBITDAX			527	202	647	1,106	1,204
Net impact of financial derivatives(a)			(12)	285	(200)	47	(99)
Impairments and ceiling test charges			10	1	62	158	25
Transition and restructuring costs(b)			8	215	5	6	
Dividends from unconsolidated affiliate(c)			17	13	8	46	50
(Income) loss from unconsolidated affiliate(d)			(6)	1	5	7	7
Non-cash compensation expense(e)			14	35	6	21	18
Management fee(f)			13	16			
Loss on extinguishment of debt(g)			3	14			
Adjusted EBITDAX			574	782	533	1,391	1,205
Less: Adjusted EBITDAX divested assets(h)			11	31	75	559	700
Pro Forma Adjusted EBITDAX	$	$	$ 563	$ 751	$ 458	$ 832	$ 505

(a) Represents the non-cash net change in the fair value of derivatives, net of actual cash settlements received/(paid) related to these derivatives, including any related cash premiums.

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

(c) Represents cash dividends received from Four Star, our unconsolidated affiliate in which we hold an approximate 49% equity interest.

(d) Reflects the elimination of non-cash 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.

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

(f) Represents the pro-rata portion of the annual management fee to be paid to affiliates of the Sponsors and other investors. The annual management fee of $25 million will terminate in connection with the closing of this offering.

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

(h) Consists of Adjusted EBITDAX contributions related to assets that have been or are in the process of being divested, including our (i) Brazil operations, (ii) CBM, South Texas and Arklatex assets, (iii) Gulf of Mexico assets, (iv) Blue Creek West, Minden and Powder River operations and (v) Catapult operations and Altamont processing plant and related gathering systems.

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Summary Pro Forma Operating and Reserve Information

Proved Reserves

The following table summarizes our estimated net proved reserves and related PV-10 as of June 30, 2013, after giving effect to our pending and recently completed divestitures described in " Recent Divestitures." The proved reserves as of June 30, 2013 are 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 "Risk Factors." Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at June 30, 2013. You should refer to "Risk Factors," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business" in evaluating the material presented below. The information in the following table does not give any effect to or reflect our commodity hedges.

Ryder Scott conducted an audit of the estimates of the proved reserves that we prepared as of June 30, 2013 and concluded that the overall procedures and methodologies we utilized in preparing these estimates 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.

		Pro Forma as of June 30, 2013
Proved reserves(1):		
Natural gas (MMcf)		1,024,768
Oil/Condensate (MBbls)		287,194
NGLs (MBbls)		42,972
Total estimated net proved reserves (MBoe)		500,960
Proved developed producing (MBoe)		167,425
Proved developed non-producing (MBoe)		18,752
Proved undeveloped (MBoe)		314,784
Percent proved developed reserves (%)		37%
PV-10 (in millions)(2)	$	7,386

(1) Includes our approximate 49% equity interest in Four Star. Net proved reserves represented by our approximate 49% interest in Four Star as of June 30, 2013 were 34.3 MMBoe, consisting of 2.1 MMBbls of oil, 6.2 MMBbls of NGLs and 155.9 Bcf of natural gas.

(2) PV-10 is a non-GAAP measure and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Our PV-10 differs from our standardized measure because our standardized measure reflects discounted future income taxes related to our investment in Four Star. For our domestic operations we were not subject to federal income taxes as of June 30, 2013. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the relative monetary significance of our oil, natural gas and NGLs properties regardless of tax structure. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil, natural gas and NGLs properties. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil (including NGLs) and natural gas reserves. The unweighted arithmetic average of the historical first-day-of-the-month prices for the prior 12 months was $91.60 per barrel of oil and $3.44 per MMBtu of natural gas as of June 30, 2013.

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The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows (in millions):

	Pro Forma as of June 30, 2013
PV-10	$ 7,386
Income taxes, discounted at 10%	(99)
Standardized measure of discounted future net cash flows	$ 7,287

Production, Revenues and Price History

The following table sets forth information regarding net production and certain price and cost information for each of the periods indicated.

	Six months ended June 30, 2013	Year ended December 31, 2012	Year ended December 31, 2011
Production data(1):			
Oil/Condensate (MBbls)	6,015	8,986	4,760
Natural gas (MMcf)	57,179	150,409	136,750
NGLs (MBbls)	1,327	1,779	794
Combined production (MBoe)	16,873	35,833	28,345
Average combined daily production (MBoe/d)	93.2	97.9	77.7
Average realized prices on physical sales(2):			
Oil (Bbl)	$ 94.81	$ 92.02	$ 88.36
Natural gas (Mcf)	3.42	2.57	3.82
NGLs (Bbl)	28.68	36.93	52.39
Average realized prices, including financial derivative settlements(2)(3):			
Oil (Bbl)	$ 101.39	$ 97.61	$ 86.78
Natural gas (Mcf)	3.12	5.08	6.64
NGLs (Bbl)	28.68	36.93	52.39
Average cash operating cost per Boe(4):			
Lease operating expenses	$ 5.11	$ 3.49	$ 3.29
Production taxes(5)	3.01	2.04	1.38
General and administrative expenses	7.36	13.04	6.29
Taxes other than production and income taxes	(0.56)	(0.10)	0.20
Total	$ 14.92	$ 18.47	$ 11.16
Depreciation, depletion and amortization	$ 17.73	$ 12.25	$ 12.93

(1) Includes the production amounts represented by our approximate 49% equity interest in Four Star. Specifically, production amounts represented by our approximate 49% equity interest in Four Star (i) as of December 31, 2012 were 282 MBbls oil and condensate, 15,552 MMcf natural gas, 478 MBbls NGLs, 3,352 MBoe combined production and 9.2 MBoe/d average combined daily production and (ii) as of June 30, 2013 were 136 MBbls oil and condensate, 7,317 MMcf natural gas, 229 MBbls NGLs, 1,585 MBoe combined production and 8.8 MBoe/d.

(2) Average prices shown in the table do not include Four Star production.

(3) Amounts reflect settlements on derivative instruments, including cash premiums.

(4) Total adjusted cash operating costs per unit for each period were $12.63/Boe, $9.94/Boe and $10.10/Boe. Adjusted cash operating cost is a non-GAAP measure. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Year-to-Date Period Ended June 30, 2013 to Year-to-Date Period Ended June 30, 2012 Operating Expenses Cash Operating Costs and Adjusted Cash Operating Costs" for a reconciliation of this measure to operating expenses, the most directly comparable GAAP measure.

(5)

Production taxes include ad valorem and severance taxes.

RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risks and uncertainties described below, as well as other information contained in this prospectus, before investing in our common stock. If any of the following risks actually occur, our business, financial condition, operating results or cash flow could be materially and adversely affected. Additional risks and uncertainties not presently known to us or not believed by us to be material may also negatively impact us.

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 other 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;
- 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.

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***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 become 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 production 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 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.

In addition, we have certain areas in which we have incurred material costs to explore for and develop reserves. These unproved property costs include non-producing leasehold, geological and geophysical costs associated with unevaluated leasehold or drilling interests, and exploration drilling costs in investments in unproved properties and major development projects in which we own a direct interest. If costs are determined to be impaired, we record in our income statement the amount of any impairment.

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

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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 due to 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 has been 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.

In addition, our commodity derivative activities could have the effect of reducing our revenue and net income. As of June 30, 2013, the net unrealized asset represented by our commodity hedging contracts was $186 million. We may continue to incur significant unrealized gains or losses in the future from our commodity derivative activities to the extent market prices increase or decrease and our hedging arrangements remain in place.

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 still ongoing, and we cannot yet predict the ultimate effect of the rules and regulations on our business.

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We currently qualify as a "non-financial entity" for purposes of the End-User Exception and expect to satisfy the other requirements of the End-User Exception. As a result, our hedging activity will not be subject to mandatory clearing, 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. Although the CFTC is appealing that decision and, if unsuccessful, is likely to adopt a new rule, we cannot predict whether or when such a rule will be adopted or the effect of such a 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 2013 of approximately $1.9 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 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 equity and debt markets and complete future asset monetization transactions is also dependent upon oil, natural gas and NGLs prices, in addition to a number of other

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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 stockholder'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

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

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

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

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

Our industry is cyclical, and historically there have been shortages of drilling rigs, equipment, supplies or qualified personnel. 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.

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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 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

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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.

Some of our operations and interests are subject to joint ventures or are operated by other companies, including our approximate 49% equity interest in Four Star. Although we operate the substantial majority of the properties in our business, certain of our properties are operated by joint venture partners or other third-party working interest owners. In certain 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 six months ended June 30, 2013, three purchasers accounted for more than 74% of our oil revenues. We depend upon a limited number of significant purchasers for the sale of most of our production. The loss of any of these customers should we be unable to replace them could adversely affect our revenues and have a material adverse effect on our financial condition and results of operations. We cannot assure you that any of our customers will continue to do business with us or that we will continue to have access to suitably liquid markets for our future production.

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

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

- the location of wells;
- methods of drilling and completing wells;
- allowable production from wells;
- unitization or pooling of oil and gas properties;
- spill prevention plans;
- limitations on venting or flaring of natural gas;
- disposal of fluids used and wastes generated in connection with operations;
- access to, and surface use and restoration of, well properties;

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- plugging and abandoning of 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, over time 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. 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

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

The leadership of our executive officers and other members of our senior management has been a critical element of our success. These individuals have substantial experience and expertise in our business and have made significant contributions to our 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 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

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bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

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

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

We describe potential drilling locations and our plans to explore those potential drilling locations in this prospectus. 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 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.

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

The marketability of our oil, natural gas and NGLs production depends in large part on the operation, availability, proximity, capacity and expansion of processing, gathering and transportation facilities owned by third parties. We can provide no assurance that sufficient processing, gathering and/or transportation capacity will exist or that we will be able to obtain sufficient processing, gathering and/or transportation capacity on economic terms. A lack of available capacity on processing, gathering and transportation facilities or delays in their planned expansions could result in the shut-in of producing wells or the delay or discontinuance of drilling plans for properties. A lack of availability of these facilities for an extended period of time could negatively impact our revenues. In addition, we have entered into contracts for firm transportation and any failure to renew those contracts on the same or better commercial terms could increase our costs and our exposure to the risks described above.

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

Water currently is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from local land owners for use in our operations. According to the Lower Colorado River Authority, during 2011, Texas experienced the lowest inflows of water of any year in recorded history. As a result of this severe drought, 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;
- 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 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 and 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

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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.

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 Department of the Interior ("DOI"), the Bureau of Indian Affairs ("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

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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 be sold by the end of the first quarter of 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. 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 other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. 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 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.

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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.

Partially as a result of an explosion on an offshore platform of a third party in 2010 and subsequent release of oil into the Gulf of Mexico, there have been various regulations proposed and implemented that could materially impact the costs of exploration and production operations, as well as 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 also 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,

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

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

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

We use hydraulic fracturing extensively in our operations. The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The Safe Drinking Water Act (the "SDWA") regulates the underground injection of substances through the Underground Injection Control ("UIC") program. While hydraulic fracturing generally is exempt from regulation under the UIC program, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the UIC program as "Class II" UIC wells. On October 21, 2011, the EPA announced its intention to propose federal Clean Water Act regulations 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 16, 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 is presently subject to an extended 90-day public comment period, which ended on August 23, 2013.

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.

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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. The EPA revised portions of these rules on August 2, 2013 (awaiting Federal Register publication) for VOCs emissions for production oil and gas storage tanks, in part phasing in emissions controls on storage tanks past October 15, 2013. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

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" takes 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 Bureau of Land Management ("BLM") has proposed rules requiring similar disclosure of hydraulic fracturing fluid used on BLM lands to FracFocus.org and optionally directly to the BLM.

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

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

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

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

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current expensing of intangible drilling and development costs;
- the elimination of the deduction for certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will be enacted or how soon such changes could be effective. The elimination of such U.S. federal tax deductions, as well as any other changes to or the imposition of new federal, state, local or non-U.S. taxes (including 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 by the end of the first quarter of 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 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 condensed consolidated financial statements included elsewhere in this prospectus. 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 have 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 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.

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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 substantial indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from making debt service payments.

We are a highly leveraged company. As of June 30, 2013, after giving effect to our pending and recently completed divestitures and repayment of certain debt obligations, we had approximately $4.1 billion of outstanding indebtedness, and for the six months ended June 30, 2013, after giving effect to our pending and recently completed divestitures and repayment of certain debt obligations, we had total debt service payment obligations of $154 million.

Our substantial indebtedness could have important consequences for you. For example, it could:

- limit our ability to borrow money for our working capital, capital expenditures, debt service requirements, strategic initiatives or other purposes;
- make it more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt instruments, including restrictive covenants and borrowing conditions, could result in an event of default under the agreements governing our indebtedness;
- require us to dedicate a substantial portion of our cash flow from operations to the repayment of our indebtedness, thereby reducing funds available to us for other purposes;
- limit our flexibility in planning for, or reacting to, changes in our operations or business;
- make us more highly leveraged than some of our competitors, which may place us at a competitive disadvantage;
- make us more vulnerable to downturns in our business or the economy;
- restrict us from making strategic acquisitions, engaging in development activities, introducing new technologies or exploiting business opportunities;
- cause us to make non-strategic divestitures;
- limit, along with the financial and other restrictive covenants in our indebtedness, among other things, our ability to borrow additional funds or dispose of assets; or
- expose us to the risk of increased interest rates, as certain of our borrowings, including borrowings under the RBL Facility and our senior secured term loan, are at variable rates of interest.

In addition, the agreements governing our indebtedness contain restrictive covenants that limit our ability to engage in activities that may be in our long-term best interest. Our failure to comply with those covenants could result in an event of default which, if not cured or waived, could result in the acceleration of substantially all of our indebtedness.

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Despite our substantial indebtedness, we may still be able to incur significantly more debt, which could intensify the risks described above.

We and our subsidiaries may be able to incur substantial indebtedness in the future. Although the terms of the agreements governing our indebtedness contain restrictions on our ability to incur additional indebtedness, these restrictions are subject to a number of important qualifications and exceptions, and the indebtedness incurred in compliance with these restrictions could be substantial. These restrictions also will not prevent us from incurring obligations that do not constitute indebtedness. After completion of this offering, we will have $2.5 billion available for borrowing under the RBL Facility, all of which would be secured. In addition, the covenants under any other existing or future debt instruments could allow us to incur a significant amount of additional indebtedness. The more leveraged we become, the more we, and in turn our investors, will be exposed to certain risks described above under " Our substantial indebtedness could adversely affect our ability to raise additional capital to fund our operations, limit our ability to react to changes in the economy or our industry and prevent us from making debt service payments."

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness that may not be successful.

Our ability to pay principal and interest on our debt obligations will depend upon, among other things:

- our future financial and operating performance, which will be affected by prevailing economic, industry and competitive conditions and financial, business, legislative, regulatory and other factors, many of which are beyond our control; and

- our future ability to borrow under the RBL Facility, which depends on, among other things, our compliance with the covenants in the credit agreement governing such facility.

We cannot assure you that our business will generate cash flow from operations, or that we will be able to draw under the RBL Facility or otherwise, in an amount sufficient to fund our liquidity needs, including the payment of principal and interest on our debt obligations.

If our cash flows and capital resources are insufficient to service our indebtedness, we may be forced to reduce or delay capital expenditures, sell assets, seek additional capital or restructure or refinance our indebtedness. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of existing or future debt agreements may restrict us from adopting some of these alternatives. If we are required to dispose of material assets or operations to meet our debt service and other obligations, we may not be able to consummate those dispositions for fair market value or at all. Furthermore, any proceeds that we could realize from any such dispositions may not be adequate to meet our debt service obligations then due. The Sponsors and their affiliates have no continuing obligation to provide us with debt or equity financing. Our inability to generate sufficient cash flow to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, could result in a material adverse effect on our business, results of operations and financial condition and could negatively impact our ability to satisfy our obligations under our indebtedness, which in turn could negatively impact your investment in our common stock.

If we cannot make scheduled payments on our indebtedness, we will be in default and lenders could declare all outstanding principal and interest to be due and payable, terminate their commitments to loan money, foreclose against the assets securing their indebtedness and we could be

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forced into bankruptcy or liquidation. All of these events could cause you to lose all or part of your investment in our common stock.

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 significant operating and financial restrictions on us, including restrictions on our and our subsidiaries ability to, among other things:

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

In addition, the RBL Facility requires us to comply with certain financial covenants. See "Description of Certain Indebtedness The RBL Facility."

As a result of these covenants, we will 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.

If any of our outstanding indebtedness under the RBL Facility or our other indebtedness were to be accelerated, there can be no assurance that our assets would be sufficient to repay such indebtedness in full. See "Description of Certain Indebtedness."

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Risks Related to This Offering and Our Common Stock

There is no existing market for our common stock, and we do not know if an active trading market will develop, which could impede your ability to sell your shares and may depress the market price of our common stock.

There has not been a public market for our common stock prior to this offering. We cannot predict the extent to which investor interest in us will lead to the development of an active trading market or how liquid that market might become. If an active trading market does not develop, you may have difficulty selling any of our common stock that you buy. The initial public offering price for the common stock will be determined by negotiations between us and the underwriters and may not be indicative of prices that will prevail in the open market following this offering. See "Underwriting." Consequently, you may be unable to sell our common stock at prices equal to or greater than the price you pay in this offering.

The interests of our Sponsors may conflict with or differ from your interests as a stockholder.

After the consummation of this offering, our Sponsors, as a group, will collectively own approximately % of our common stock, assuming the underwriters do not exercise their option to purchase additional shares, or % if the underwriters exercise their option in full. As a result, subject to the rights of the other Legacy Class A Stockholders contained in the Stockholders Agreement described in this prospectus, our Sponsors will continue to control all matters affecting us, including decisions regarding extraordinary business transactions, fundamental corporate transactions, appointment of members to our management, election of directors and our corporate and management policies. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of our Sponsors with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, could conflict with your interests as a holder of our common stock. For example, the concentration of ownership held by our Sponsors could delay, defer or prevent a change of control of us or impede a merger, takeover or other business combination that you as a stockholder may otherwise view favorably. Further, a sale of a substantial number of shares of stock in the future by our Sponsors could cause our stock price to decline.

In addition, the Stockholders Agreement that we have entered into with the Sponsors and the other Legacy Class A Stockholders provides that, except as otherwise required by applicable law, the Sponsors will have certain rights with respect to the designation of directors to serve on our Board. See "Certain Relationships and Related Party Transactions Stockholders Agreement Composition of the Board." In addition, 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 Party Transactions."

Furthermore, the Sponsors and their respective affiliates either operate businesses, or may from time to time acquire businesses, that compete directly or indirectly with us, as well as businesses that represent major customers of our business, or are in the business of making investments, or managing funds that make investments, in companies and one or more of them may from time to time acquire and hold interests, or manage funds that acquire and hold interests, in businesses that compete directly or indirectly with us, as well as businesses that represent major customers of our business. The Sponsors and their affiliates, including funds managed by certain of the Sponsors and their respective affiliates, may also pursue acquisition opportunities that may be complementary to our business and, as a result, those acquisition opportunities may not be available to us.

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Our Second Amended and Restated Certificate of Incorporation to be effective upon the completion of this offering (the "Second Amended and Restated Certificate of Incorporation") provides that we expressly renounce any interest or expectancy in any business opportunity in which any Legacy Class A Stockholder or any of our directors who is also, without limitation, an employee, partner, officer or director of a Legacy Class A Stockholder or any of their affiliates (each, a "Covered Person") participates or desires or seeks to participate in. See "Certain Relationships and Related Party Transactions Stockholders Agreement" and "Description of Capital Stock Corporate Opportunity."

We will be a "controlled company" within the meaning of the NYSE rules and, as a result, will qualify for, and intend to rely on, exemptions from certain corporate governance requirements.

Upon the closing of this offering, our Sponsors and the other Legacy Class A Stockholders, as a group, will continue to control a majority of our voting common stock. As a result, we will be a "controlled company" within the meaning of applicable corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by an individual, group or another company is a "controlled company" and may elect not to comply with certain corporate governance requirements, including:

- the requirement that we have a majority of independent directors on our Board;
- the requirement that we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the requirement that we have a compensation committee that is composed entirely of independent directors; and
- the requirement for an annual performance evaluation of the nominating and compensation committees.

Following this offering, we intend to utilize the foregoing exemptions from the applicable corporate governance requirements. As a result, we will not have a majority of independent directors. In addition, our compensation committee will not consist entirely of independent directors and we will not be required to have an annual performance evaluation of the compensation committee. See "Management." Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the NYSE's corporate governance requirements.

The price of our common stock may fluctuate significantly and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- changes in earnings estimates or recommendations by securities analysts who track our common stock or industry;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy; and
- sales of common stock by us, our stockholders, our Sponsors, or members of our management team.

In addition, the stock market has experienced significant price and volume fluctuations in recent years. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industry, and the changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with us, and these fluctuations could materially reduce our share price.

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We currently have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

We currently have no plans to pay regular dividends on our common stock. Any payment of future dividends will be at the discretion of our Board and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, contractual restrictions applying to the payment of dividends, and other considerations that our Board deems relevant. The terms of the agreements governing our indebtedness include limitations on our ability to pay dividends and/or the ability of our subsidiaries to pay dividends to us. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

We are a holding company and rely on dividends and other payments, advances and transfers of funds from our subsidiaries to meet our dividend and other obligations.

We are a holding company and have no direct operations and no material assets other than our direct or indirect ownership of 100% of the equity interests of EPE Acquisition, our wholly owned holding company that holds our operating subsidiaries indirectly through its subsidiaries. Because we conduct our operations through our subsidiaries, we depend on those entities for dividends and other payments to generate the funds necessary to meet our financial obligations and to pay any dividends on our common stock and have no other means of generating revenue. Legal and contractual restrictions in the RBL Facility, our other existing debt agreements and other agreements that may govern future indebtedness of our subsidiaries, may limit our ability to obtain cash from our subsidiaries. The earnings from, or other available assets of, our subsidiaries may not be sufficient to pay dividends or make distributions or loans to enable us to pay any dividends on our common stock or other obligations. To the extent we need funds and EPE Acquisition or any of our other subsidiaries are restricted from making such distributions under applicable law or regulation or under the terms of their financing arrangements, or they are otherwise unable to provide such funds, it could materially adversely affect our liquidity and financial condition.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock.

We may sell additional shares of common stock in subsequent public offerings or otherwise, including to finance acquisitions. Our Second Amended and Restated Certificate of Incorporation authorizes us to issue shares of common stock, of which shares will be outstanding upon completion of this offering (if the underwriters' option to purchase additional shares is exercised in full). The outstanding share number includes shares that we are selling in this offering, which may be resold immediately in the public market. The remaining outstanding shares are restricted from immediate resale under the lock-up agreements with the underwriters described in "Underwriting," but may be sold into the market in the near future. Following the expiration of the applicable lock-up period, which is days after the date of this prospectus, shares of our common stock will be freely transferable without restriction or further registration under the Securities Act, except for any such shares which are held or may be acquired by any of our "affiliates" as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144. See "Shares Eligible for Future Sale" for a discussion of the shares of our common stock that may be sold into the public market in the future.

Pursuant to the Registration Rights Agreement, the Legacy Class A Stockholders have certain rights to demand underwritten registered offerings in respect of the approximately shares of common stock that they will own immediately following this offering, and we have granted the Sponsors and the other Legacy Class A Stockholders incidental registration rights, in respect of shares of common stock. Upon the effectiveness of a registration statement, all shares covered by the registration statement would be freely transferable without restriction or further registration under the Securities Act, except for any such shares which are held or may be acquired by any of our "affiliates" as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144. See "Certain Relationships and Related Party Transactions Registration Rights Agreement."

Pursuant to our Second Amended and Restated Certificate of Incorporation, in connection with certain sales of common stock by Apollo and/or Riverstone (the "Specified Stockholders"), holders of Class B common stock will have their Class B shares exchanged for shares of newly issued common stock. In connection with the exchanges of Class B common stock, we intend to file one or more shelf registration statements under the Securities Act covering the newly issued shares of common stock. Accordingly, these registered shares may become available for sale in the open market upon the completion of such exchanges, subject to Rule 144 limitations applicable to our affiliates. See "Description of Capital Stock Class B common stock" and "Description of Capital Stock Class B Exchange." As soon as practicable after the completion of this offering, we intend to file a registration statement on Form S-8 under the Securities Act covering shares of our common stock reserved for issuance under the Omnibus Incentive Plan described elsewhere in this prospectus. Accordingly, shares of our common stock registered under such registration statement may become available for sale in the open market upon grants under the Omnibus Incentive Plan, subject to vesting restrictions, Rule 144 limitations applicable to our affiliates and contractual lock-up provisions.

We cannot predict the size of future issuances of our common stock or the effect, if any, that future issuances and sales of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including any shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices for our common stock.

Our organizational documents and the Stockholders Agreement may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our Second Amended and Restated Certificate of Incorporation, our amended and restated bylaws to be effective upon the completion of this offering (our "Amended and Restated Bylaws") and the Stockholders Agreement may make it more difficult for, or prevent a third party from, acquiring control of us without Special Board Approval (as defined below). These provisions include:

- granting each Sponsor, for so long as it beneficially owns certain percentages of its ownership of common stock as of the effective time of the registration statement of which this prospectus forms a part (the "Effective Time"), the right to designate a certain number of directors and the sole right to remove any director designated by it, with or without cause, and to fill any vacancy caused by the removal of any such director;

- classifying our Board into three classes of directors;

- prohibiting cumulative voting in the election of directors;

- authorizing the issuance of "blank check" preferred stock without stockholder approval; and

- for so long as the Negative Control Condition (as defined below) is satisfied, requiring Special Board Approval (as defined below) for certain corporate actions, including amendments to our organizational documents, equity issuances, acquisitions or dispositions of material assets, changing the composition of our Board, hiring or firing our chief executive officer, chief financial officer and any other member of senior management and certain other significant matters (see "Certain Relationships and Related Party Transactions Stockholders Agreement").

In addition, for so long as the Negative Control Condition is satisfied, our Board may, by Special Board Approval, issue preferred stock in one or more series, designate the number of shares constituting any series, and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, redemption price or prices and liquidation preferences of such series. The issuance of preferred stock may have the effect of delaying,

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deferring or preventing a change in control without further action by the stockholders, even where stockholders are offered a premium for their shares. Under our Stockholders Agreement, (i) "Negative Control Condition" means that the Legacy Class A Stockholders hold at least 25% of our outstanding common stock and either Apollo or Riverstone is entitled to designate at least one director pursuant to the Stockholders Agreement and (ii) "Special Board Approval" means the approval by a majority of our Board, which majority includes (a) at least one director designated to our Board by Apollo and (b) at least one director designated to our Board by one of the other Sponsors or one replacement director designated to our Board 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 in the event a Sponsor has lost its right to designate its applicable director and the Legacy Class A Stockholders hold at least 50% of our outstanding common stock.

Together, our organizational documents and the Stockholders Agreement could make the removal of management more difficult and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our common stock. Furthermore, the existence of the foregoing provisions, as well as the significant common stock owned by the Sponsors following this offering and their individual rights to designate a specified number of directors in certain circumstances, could limit the price that investors might be willing to pay in the future for our common stock. Our organizational documents and the Stockholders Agreement could also deter potential acquirers of us, thereby reducing the likelihood that you could receive a premium for your common stock in an acquisition. See "Description of Capital Stock Certain Anti-Takeover, Limited Liability and Indemnification Provisions" and See "Certain Relationships and Related Party Transactions Stockholders Agreement Consent Rights."

The corporate opportunity provisions in our Second Amended and Restated Certificate of Incorporation could enable the Sponsors to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our Second Amended and Restated Certificate of Incorporation provides, among other things, that:

- any Covered Person has the right to, and has no duty to abstain from, exercising such right to conduct business with any business that is competitive or in the same line of business as us, do business with any of our clients or customers, or invest or own any interest publicly or privately in, or develop a business relationship with, any business that is competitive or in the same line of business as us;

- if a Covered Person acquires knowledge of a potential transaction that could be a corporate opportunity, he or she has no duty to offer such corporate opportunity to us; and

- we have renounced any interest or expectancy in, or in being offered an opportunity to participate in, such corporate opportunities.

As a result, the Legacy Class A Stockholders and their affiliates may become aware, from time to time, of certain business opportunities, such as acquisition opportunities, and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be presented to the Legacy Class A Stockholders and their affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours. Please read "Description of Capital Stock Corporate Opportunities."

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We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies, as described under the caption "Certain Relationships and Related Party Transactions." The resolution of any conflicts that may arise in connection with any related party transactions that we have entered into with the Sponsors, the other Legacy Class A Stockholders or their affiliates, including pricing, duration or other terms of service, may not always be in our or our stockholders' best interests because the Sponsors and the other Legacy Class A Stockholders may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, please read " The interests of our Sponsors may conflict with or differ from your interests as a stockholder."

You will experience an immediate and substantial dilution in the net tangible book value of the common stock you purchase.

After giving effect to this offering and the other adjustments described in "Dilution," we expect that our pro forma as adjusted net tangible book value as of June 30, 2013 would be $ per share. Based on an assumed initial public offering price of $ per share, the midpoint of the range set forth on the cover page of this prospectus, you will experience immediate and substantial dilution of approximately $ per share in net tangible book value of the common stock you purchase in this offering. See "Dilution," including the discussion of the effects on dilution from a change in the price of this offering.

We may issue preferred stock with terms that could adversely affect the voting power or value of our common stock.

Our Second Amended and Restated Certificate of Incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our Board may determine, subject to Special Board Approval for so long as the Negative Control Condition is satisfied. The terms of any class or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock. See "Description of Capital Stock Certain Anti-Takeover, Limited Liability and Indemnification Provisions."

We have issued shares of Class B common stock to management with terms that may adversely affect the value of our common stock.

Certain of our employees and members of our management team indirectly hold 808,304 shares of our Class B common stock, par value $0.01 per share. In addition, we will issue an additional 70,000 shares of our 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 the proceeds paid in respect of such shares of Class B common stock pursuant to the Second Amended and Restated Certificate of Incorporation. The terms, preferences and rights of the Class B common stock set forth in our Second Amended and Restated Certificate of Incorporation may under certain circumstances reduce the amount of dividends and liquidation proceeds otherwise distributable to holders of common stock and dilute existing holders of common stock as a result of an exchange of shares of Class B common stock for shares of common stock. 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 a liquidation of the

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company. In connection with certain sales of shares of common stock by Apollo and Riverstone, holders of shares of Class B common stock will have their shares exchanged for shares of newly issued common stock. 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 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 an exchange will depend on the return on invested capital in the Company and EPE Acquisition received by Apollo and Riverstone subject to an adjustment multiple (with respect to exchanges of Class B common stock). See "Description of Capital Stock Class B common stock," "Description of Capital Stock Distributions Upon a Liquidation" and "Description of Capital Stock Class B Exchange."

The additional requirements of having a class of publicly traded equity securities may strain our resources and distract management.

Even though EP Energy LLC currently files reports with the SEC, after the consummation of this offering, we will be subject to additional reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the Sarbanes-Oxley Act of 2002 (the "Sarbanes-Oxley Act") and the Dodd-Frank Act. The Dodd-Frank Act effects comprehensive changes to public company governance and disclosures in the United States and will subject us to additional federal regulation. We cannot predict with any certainty the requirements of the regulations ultimately adopted or how the Dodd-Frank Act and such regulations will impact the cost of compliance for a company with publicly traded common stock. We are currently evaluating and monitoring developments with respect to the Dodd-Frank Act and other new and proposed rules and cannot predict or estimate the amount of the additional costs we may incur or the timing of such costs. All laws, regulations and standards are subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. We intend to invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management's time and attention from revenue-generating activities to compliance activities. If our efforts to comply with new laws, regulations and standards differ from the activities intended by regulatory or governing bodies due to ambiguities related to practice, regulatory authorities may initiate legal proceedings against us and our business may be harmed. We also expect that being a company with publicly traded common stock subject to these new rules and regulations will make it more expensive for us to obtain director and officer liability insurance, and we may be required to accept reduced coverage or incur substantially higher costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our Board, particularly to serve on our audit committee, and qualified executive officers.

The Sarbanes-Oxley Act requires that we maintain effective disclosure controls and procedures and internal control over financial reporting. These requirements may place a strain on our systems and resources. Under Section 404 of the Sarbanes-Oxley Act, we will be required to include a report of management on our internal control over financial reporting in our Annual Reports on Form 10-K beginning with the Form 10-K for the year ending December 31, 2014. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight will be required. This may divert management's attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. If we are unable to conclude that our disclosure controls and procedures and internal control over financial reporting are effective, investors may lose confidence in our financial reports and our stock price may decline.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus 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-looking statements. All of our forward-looking statements are expressly qualified by these and the other cautionary statements in this prospectus, including those set forth in "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 our 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 "Risk Factors."

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 our forward-looking statements, whether as a result of new information, subsequent events, anticipated or unanticipated circumstances or otherwise.

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USE OF PROCEEDS

Assuming an initial public offering price of $ per share, the midpoint of the range set forth on the cover page of this prospectus, we estimate that we will receive net proceeds from this offering of approximately $ million, after deducting underwriting discounts and commissions and other estimated expenses of $ million payable by us.

Each $1.00 increase (decrease) in the assumed initial public offering price of $ per share would increase (decrease) the net proceeds to us from this offering by $ million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated expenses payable by us. An increase (decrease) of 1,000,000 in the number of shares we are offering would increase (decrease) the net proceeds to us from this offering, after deducting the estimated underwriting discounts and commissions and estimated expenses payable by us, by approximately $ million, assuming the initial public offering price per share remains the same.

We intend to use the net proceeds from this offering (i) to redeem all of the outstanding 8.125%/8.875% Senior PIK Toggle Notes due 2017 issued by our subsidiaries, EPE Holdings LLC and EP Energy Bondco Inc., and pay the redemption premium and the accrued and unpaid interest on the notes, (ii) to repay outstanding borrowings under the RBL Facility, (iii) to pay an approximately $ million fee under the transaction fee agreement with certain affiliates of our Sponsors and (iv) for general corporate purposes. We will also reimburse the Legacy Stockholders for expenses incurred in connection with the Corporate Reorganization and this offering.

The PIK notes were issued on December 21, 2012 and mature on December 15, 2017. The issuers may elect to pay interest on the PIK notes (i) in cash, (ii) by increasing the principal amount of the outstanding notes or issuing new notes ("PIK interest") or (iii) in cash on 50% of the outstanding principal amount of the notes and in PIK interest on the remaining 50% of the outstanding principal amount of the notes. The PIK notes accrue cash interest at a rate of 8.125% per annum and PIK interest at a rate of 8.875% per annum. The PIK notes may be redeemed with the net cash proceeds of this offering at a redemption price equal to 102% of the principal amount plus accrued and unpaid interest to the redemption date. See "Description of Certain Indebtedness Senior PIK Toggle Notes." As of August 31, 2013, we had $372 million of outstanding aggregate principal amount of PIK notes.

As of August 31, 2013, we had $175 million of outstanding borrowings under the RBL Facility. The RBL Facility matures on May 24, 2017 and bears interest at LIBOR plus 1.50%. The borrowings to be repaid were incurred primarily to fund capital expenditures and other general corporate expenditures. See "Description of Certain Indebtedness RBL Facility."

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DIVIDEND POLICY

We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends in the future will be made by our Board in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements and other contracts, including requirements under our Second Amended and Restated Certificate of Incorporation and the Stockholders Agreement described elsewhere in this prospectus, and other factors our Board deems relevant. See "Certain Relationships and Related Party Transactions Stockholders Agreement."

We are a holding company and have no direct operations. We will only be able to pay dividends from our available cash on hand and funds received from our subsidiaries, whose ability to make any payments to us will depend upon many factors, including their operating results and cash flows. In addition, the RBL Facility and the indentures governing our subsidiaries' existing notes limit the ability of our subsidiary, EP Energy LLC, to pay distributions on its equity interests. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources," " Contractual Obligations," " Commitments and Contingencies" and "Description of Certain Indebtedness."

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CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of June 30, 2013:

(1) on a historical basis,

(2) on a pro forma as adjusted basis to give effect to (i) our pending and completed divestitures and the use of proceeds therefrom as described in "Summary Recent Divestitures," (ii) the repayment of $500 million under our senior secured term loans in August 2013, and (iii) the $200 million distribution EPE Acquisition made to its members in August 2013, and

(3) on a pro forma as further adjusted basis to give effect to (i) the Corporate Reorganization and (ii) our sale of shares of common stock in this offering at an assumed offering price of $, which is the midpoint of the range listed on the cover page of this prospectus, and our use of the estimated net proceeds from this offering as described under "Use of Proceeds."

You should read this table in conjunction with "Selected Historical Consolidated Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our historical consolidated financial statements and the related notes appearing elsewhere in this prospectus, as well as the sections "Summary Summary Historical and Pro Forma Consolidated Financial Data," "Use of Proceeds" and "Unaudited Pro Forma Condensed Consolidated Financial Data" included in this prospectus.

	June 30, 2013		
	EPE Acquisition, LLC Historical(1)	EP Energy Corporation Pro Forma as Adjusted	EP Energy Corporation Pro Forma as Further Adjusted(2)
	(in millions)		
Cash and cash equivalents	$ 283	$ 66	$
Debt:			
RBL Facility(3)	$ 785	$	$
Senior secured term loans	1,142	642	
Senior secured notes due 2019	750	750	
9.375% senior notes due 2020	2,000	2,000	
7.750% senior notes due 2022	350	350	
8.125% / 8.875% PIK notes due 2017	365	365	
Total debt	$ 5,392	$ 4,107	$
Total equity	2,842	2,817	
Total capitalization	$ 8,234	$ 6,924	$

(1) The data has been derived from the unaudited financial statements of EPE Acquisition included elsewhere in this prospectus.

(2) A $1.00 increase (decrease) in the assumed initial public offering price of $ per share would increase (decrease) cash and total capitalization by $ million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated expenses payable by us.

(3) At the completion of this offering, we will have borrowing availability of $2.5 billion under the RBL Facility. See "Description of Certain Indebtedness The RBL Facility."

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DILUTION

Dilution is the amount by which the offering price paid by the purchasers of the common stock to be sold in this offering exceeds the net tangible book value per share of common stock after the offering. Net tangible book value per share is determined at any date by subtracting our total liabilities from the total book value of our tangible assets and dividing the difference by the number of shares of common stock deemed to be outstanding at that date. There will be shares of our common stock reserved for future awards under the Omnibus Incentive Plan as of the consummation of this offering.

Our net tangible book value (tangible assets less total liabilities) as of June 30, 2013, after giving pro forma effect to the transactions described in " Summary Historical and Pro Forma Consolidated Financial Data" was approximately $2.8 billion, or $ per share of common stock. Pro forma net tangible book value per share is determined by dividing our pro forma net tangible book value by our shares of common stock that will be outstanding immediately prior to the closing of this offering, including giving effect to the transactions described above. After giving effect to the receipt of approximately $ million of estimated net proceeds from our sale of shares of common stock in this offering at an assumed offering price of $ per share, the midpoint of the range set forth on the front cover of this prospectus, our pro forma net tangible book value as of June 30, 2013 would have been approximately $ million, or $ per share. This represents an immediate decrease in our pro forma net tangible book value of $ per share to our existing stockholders and an immediate dilution of $ per share to new investors purchasing shares of common stock in the offering. The following table illustrates this substantial and immediate per share dilution to new investors:

	Per Share
Assumed initial public offering price per share	$
Pro forma net tangible book value prior to the offering	
Increase per share attributable to investors in the offering	
Pro forma net tangible book value after the offering	
Dilution per share to new investors	$

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share would decrease (increase) our pro forma net tangible book value by $ million, or $ per share, and increase (decrease) the dilution per share to new investors in this offering by $, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same and after deducting the estimated underwriting discounts and commissions and estimated expenses payable by us.

The following table summarizes on an as adjusted basis as of June 30, 2013, giving effect to:

- the total number of shares of common stock purchased from us;

- the total consideration paid to us, assuming an initial public offering price of $ per share (before deducting the estimated underwriting discount and commissions and offering expenses payable by us in connection with this offering); and

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the average price per share paid by our existing stockholders and by new investors purchasing shares in this offering:

	Shares Purchased		Total Consideration		Average Price Per Share
	Number	Percent	Amount	Percent	
Existing stockholders		%	$	%	$
Investors in this offering		%		%	
Total		100%	$	100%	$

A $1.00 increase (decrease) in the assumed initial public offering price of $ per share (the midpoint of the range set forth on the cover page of this prospectus) would increase (decrease) total consideration paid by new investors, total consideration paid by all stockholders and the average price per share by $ million, $ million and $ million, respectively, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same.

The tables and calculations above also assume no exercise of the underwriters' option to purchase additional shares. If the underwriters exercise their option to purchase additional shares in full, then new investors would purchase shares, or approximately % of shares outstanding, the total consideration paid by new investors would increase to $ million, or % of the total consideration paid (based on the midpoint of the range set forth on the cover page of this prospectus), and the additional dilution per share to new investors would be $.

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SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

We have derived the selected historical consolidated balance sheet data as of December 31, 2012 (successor) and December 31, 2011 (predecessor), and the statements of income data and statements of cash flow data for the period from February 14 (inception) to December 31, 2012 (successor), the period from January 1, 2012 through May 24, 2012 (predecessor) and each of the two years in the period ended December 31, 2011 (predecessor), from the audited consolidated financial statements of EPE Acquisition, LLC, which are included elsewhere in this prospectus. EPE Acquisition, LLC, was the ultimate holding company prior to our Corporate Reorganization. Historical financial results of EPE Acquisition, LLC in this prospectus for the period before the Acquisition on May 24, 2012, are referred to as the predecessor and after the Acquisition are referred to as the successor in accordance with the required GAAP presentation.

We have derived the selected historical consolidated balance sheet data as of December 31, 2010, 2009, and 2008, and the statements of income data and statements of cash flow data for the years ended December 31, 2009 and 2008 from the audited consolidated financial statements of EP Energy Corporation, the predecessor of EPE Acquisition, LLC and referred to herein as Historical EP Energy Corporation, which are not included in this prospectus. The selected unaudited historical consolidated financial data as of and for the six months ended June 30, 2013 (successor) and for the period from February 14, 2012 through June 30, 2012 (successor), have been derived from the unaudited consolidated financial statements of EPE Acquisition, LLC appearing elsewhere in this prospectus, which have been prepared on a basis consistent with the audited consolidated financial statements of EPE Acquisition, LLC. In the opinion of management, such unaudited financial data reflects all adjustments, consisting only of normal and recurring adjustments, necessary for a fair presentation of the results for such period. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year or any future period.

The following selected historical consolidated financial data should be read in conjunction with the information included under the headings "Summary Corporate History and Structure" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and related notes included elsewhere in this prospectus.

	EPE Acquisition, LLC						Historical EP Energy Corporation	
	Six months ended June 30, (Successor)	February 14 (inception) to June 30, (Successor)	February 14 (inception) to December 31, (Successor)	January 1 to May 24, (Predecessor)	Years ended December 31, (Predecessor)		Years ended December 31,	
	2013	2012	2012	2012	2011	2010	2009	2008
	(in millions)							
Statement of income data								
Operating revenues:								
Oil and condensate	$ 568	$ 74	$ 555	$ 322	$ 552	$ 346	$ 214	$ 436
Natural gas	215	46	278	262	973	974	830	1,960
NGL	32	4	32	29	57	60	53	105
Physical sales	815	124	865	613	1,582	1,380	1,097	2,501
Financial derivatives(1)	35	57	(62)	365	284	390	687	196
Other					1	19	44	65
Total operating revenues	850	181	803	978	1,867	1,789	1,828	2,762
Operating expenses:								
Natural gas purchases	10	4	19					
Transportation costs	46	9	51	45	85	73	66	79
Lease operating expenses	98	15	96	96	217	193	197	244
General and administrative expenses	118	208	371	75	201	190	195	160
Depreciation, depletion and amortization	277	26	217	319	612	477	440	818
Impairments/Ceiling test charges	10	1	1	62	158	25	2,148	2,824
Exploration expense	27	6	50					
Taxes, other than income taxes	43	10	51	45	91	85	68	132
Other						15	31	38
Total operating expenses	629	279	856	642	1,364	1,058	3,145	4,295
Operating income (loss)	221	(98)	(53)	336	503	731	(1,317)	(1,533)
Income (loss) from unconsolidated affiliates	6	(1)	(1)	(5)	(7)	(7)	(30)	(93)
Other income (expense)	(1)	1	3	(3)	(2)	3	(1)	7
Loss on extinguishment of debt	(3)		(14)					
Interest expense, net of capitalized interest	(178)	(53)	(219)	(14)	(12)	(21)	(25)	(57)
Income (loss) from continuing operations before income taxes	45	(151)	(284)	314	482	706	(1,373)	(1,676)
Income tax expense (benefit)	2		2	136	220	263	(462)	(413)
Income (loss) from continuing operations	$ 43	$ (151)	$ (286)	$ 178	$ 262	$ 443	$ (911)	$ (1,263)

(1) Includes $5 million for the periods from January 1 to May 24, 2012, and $11 million, $11 million, ($406) million and $88 million for the years ended December 31, 2011, 2010, 2009 and 2008, respectively, reclassified from accumulated other comprehensive income associated with accounting hedges.

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	EPE Acquisition, LLC						Historical EP Energy Corporation	
	Six Months ended June 30, (Successor)	February 14 (inception), to June 30, (Successor)	February 14 (inception), to December 31, (Successor)	January 1, to May 24, (Predecessor)	Years ended December 31, (Predecessor)		Years ended December 31,	
	2013	2012	2012	2012	2011	2010	2009	2008
	(in millions)							
Statement of cash flows data								
Net cash provided by (used in):								
Operating activities	$ 450	$ (92)	$ 449	$ 580	$ 1,426	$ 1,067	$ 1,573	$ 2,218
Investing activities	(906)	(7,254)	(7,893)	(628)	(1,237)	(1,130)	(1,156)	(993)
Financing activities	670	7,401	7,513	110	(238)	(46)	(336)	(1,237)

	EPE Acquisition, LLC			Historical EP Energy Corporation		
	As of June 30, (Successor)	As of December 31, (Successor)	As of December 31, (Predecessor)	As of December 31,		
	2013	2012	2011	2010	2009	2008
	(in millions)					
Balance sheet data						
Cash and cash equivalents	$ 283	$ 69	$ 25	$ 74	$ 183	$ 102
Total assets	9,181	8,306	5,099	4,942	4,457	6,384
Total debt	5,392	4,695	851	301	835	915
Members'/ Stockholder's equity	2,842	2,748	3,100	3,067	2,529	3,697

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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 included elsewhere in this prospectus. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in "Risk Factors." Actual results may differ materially from those contained in any forward-looking statements. Additionally, the financial results for the successor periods include the application of the acquisition method of accounting and the application of the successful efforts method of accounting for oil and natural gas properties. The successor periods also present certain of our 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 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 EPE Acquisition, LLC (subsequently reorganized as a directly and indirectly owned subsidiary of EP Energy Corporation (the issuer) in the third quarter of 2013) 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), the Uinta Basin (Utah) and the Haynesville Shale (North Louisiana).

During the third quarter of 2013, we sold certain of our natural gas properties, including our CBM properties located in the Raton, Black Warrior and Arkoma basins, the majority of our Arklatex natural gas properties and our natural gas properties in South Texas. As of June 30, 2013, these assets represented 1,014 Bcfe of proved reserves (96% natural gas). The total consideration from these transactions was approximately $1.3 billion. In addition, 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 by the end of the first quarter of 2014, subject to Brazilian regulatory approval and certain other customary closing conditions.

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

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

In addition to these factors, our future profitability and performance will be affected by 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.

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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 the six months ended June 30, 2013, approximately 95% of our liquids production and 90% of our natural gas production were hedged and settled at average floor prices of $99.93 per barrel and $3.57 per MMBtu, respectively. In conjunction with the sale of certain of our non-core natural gas assets, we entered into offsetting positions on natural gas derivatives of 36 TBtu on anticipated 2013 production and 42 TBtu on anticipated 2014 production. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of June 30, 2013.

	2013		2014		2015	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil						
Fixed Price Swaps(2)	8,684	$ 100.09	12,117	$ 97.70	6,231	$ 94.57
Ceilings	1,042	$ 98.24	1,095	$ 100.00	1,095	$ 100.00
Three Way Collars Ceiling		$	2,920	$ 103.76		$
Three Way Collars Floors(3)		$	2,920	$ 95.00		$
Basis Swaps	2,645	Various	4,380	Various	3,650	Various
Natural Gas						
Fixed Price Swaps	49	$ 3.37	67	$ 4.02	44	$ 4.28
Ceilings	1	$ 3.75	13	$ 4.02		$

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

(2) On 3,128 MBbls, if market prices settle at or below $71.47 in 2013, we will receive a "locked-in" cash settlement of the market price plus $24.27 per Bbl.

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

Between July 1 and August 29, 2013, we added fixed price oil derivatives covering volumes of 4 MMBbl, 12 MMBbl and 2 MMBbl to our 2014, 2015 and 2016 anticipated production, respectively. These derivatives are not reflected in the table above.

Summary of Liquidity and Capital Resources. As of June 30, 2013, we had available liquidity, including existing cash, of approximately $2.0 billion. We believe we have sufficient liquidity for the foreseeable future from our cash flows from operations, combined with the availability under our RBL Facility and available cash, to fund our capital spending plan, debt obligations, and projected working capital requirements. Additionally, the earliest maturity date of our debt obligations is in 2017. See "Liquidity and Capital Resources" for more information.

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Capital Expenditures. Our capital expenditures for the six months ended June 30, 2013 and rig count as of June 30, 2013 were:

	Capital Expenditures (In millions)	Rig Count
Eagle Ford Shale	$ 600	5
Wolfcamp Shale	236	3
Uinta Basin	94	2
Haynesville Shale	1	
Other	6	
Total capital expenditures	$ 937	10

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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 following periods:

	Six months ended June 30,		Year ended December 31,		
	2013	**2012**	**2012**	**2011**	**2010**
United States (MBoe/d)					
Eagle Ford Shale	33	15	20	6	1
Wolfcamp Shale	3	2	2		
Uinta Basin	11	10	11	9	8
Haynesville Shale	32	53	48	45	25
Other domestic	5	9	7	7	7
Divested assets(1)		39	20	57	74
Brazil (MBoe/d)	5	6	6	6	5
Total Consolidated	89	134	114	130	120
Unconsolidated affiliate (MBoe/d)	9	9	9	10	10
Total Combined (MBoe/d)	98	143	123	140	130
Oil and condensate (MBbls/d)					
Consolidated volumes	33	21	25	13	8
Divested assets(1)		1		3	5
Unconsolidated affiliate volumes	1	1	1	1	1
Total Combined	34	23	26	17	14
Natural Gas (MMcf/d)					
Consolidated volumes	300	425	391	355	226
Divested assets(1)		214	114	306	392
Unconsolidated affiliate volumes	40	43	42	46	47
Total Combined	340	682	547	707	665
NGLs (MBbls/d)					
Consolidated volumes	6	3	3	1	
Divested assets(1)		2	2	2	4
Unconsolidated affiliate volumes	1	1	1	1	2
Total Combined (MBbls/d)	7	6	6	4	6

(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.

Eagle Ford Shale Our Eagle Ford Shale equivalent volumes increased 18 MBoe/d for the six months ended June 30, 2013 compared to the same period in 2012 and 14 MBoe/d for the year ended December 31, 2012 compared to 2011, due in both cases to the success of our drilling program in the area. Eagle Ford oil production increased by 11 MBbls/d (or 106%) compared with the six months ended June 30, 2012. During the six months ended June 30, 2013, we drilled 67 additional wells and during the year ended December 31, 2012, we drilled 84 additional wells in our Eagle Ford area. We had a total of

203 net operated wells as of June 30, 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 NGLs production in the area.

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Wolfcamp Shale Our Wolfcamp Shale equivalent volumes increased 2 MBoe/d for the six months ended June 30, 2013 compared to the same period in 2012 and 2 MBoe/d for the year ended December 31, 2012 compared to the same period in 2011. We continue to progress the development of our Wolfcamp Shale drilling program where we drilled 17 additional wells during 2012 and drilled 25 additional wells during the first six months of 2013, for a total of 56 net operated wells as of June 30, 2013.

Uinta Basin Our Uinta Basin equivalent volumes increased 1 MBoe/d for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 and 2 MBoe/d for the year ended December 31, 2012 compared to same period in 2011. The Uinta Basin produced an average of 8 MBbls/d of oil during the six months ended June 30, 2013, and we drilled an additional 13 operated oil wells at Uinta for a total of 319 net operated wells at June 30, 2013.

Haynesville Shale Our Haynesville Shale equivalent volumes decreased 21 MBoe/d for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 and increased 3 MBoe/d for the year ended December 31, 2012 compared to same period in 2011. The decrease in 2013 was 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 June 30, 2013 we had 99 net operated wells in the Haynesville Shale, and our total production for the six months ended June 30, 2013 was approximately 189 MMcf/d.

Divested assets Our divested assets were reclassified as discontinued operations for the six-month period ended June 30, 2013 and thus volumes related to these assets were not reflected in the table above. Equivalent volumes of divested assets in 2012, 2011 and 2010 include volumes for CBM, South Texas and the majority of our Arklatex assets, each sold in 2013, and Gulf of Mexico assets sold in 2012.

Brazil Production volumes related to our Brazil operations were 5 MBoe/d in each of the six-month periods ended June 30, 2013 and 2012 and 6 MBoe/d for the year ended December 31, 2012. On July 16, 2013, we entered into a Quota Purchase Agreement to sell our Brazil operations which is expected to close by the end of the first quarter of 2014, subject to Brazilian regulatory approval and certain other customary closing conditions.

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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 long-term 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 or proved reserve additions attributable to investments accounted for using the equity method. 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 " 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 " 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."

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 June 30, 2013, proved developed reserves represented approximately 35% of our total consolidated 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 the six months ended June 30, 2013 and for each of the years ended December 31 2012, 2011 and 2010:

	Including Price Revisions				Excluding Price Revisions			
	Six months ended June 30,	Year ended December 31,			Six months ended June 30,	Year ended December 31,		
	2013	2012	2011	2010	2013	2012	2011	2010
Reserve Replacement Ratios	357%	47%	416%	370%	343%	298%	418%	306%
Reserve Replacement Costs(1)($/Boe)	$ 16.96	$ 67.56	$ 8.52	$ 7.74	$ 17.67	$ 10.74	$ 8.46	$ 9.36

(1) Proved and unproved acquisition and leasehold costs are included in all calculations. Excluding property acquisition costs would not materially impact our reserve replacement cost or reserve replacement ratio.

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 the three years ended December 31, 2012.

	Including Price Revisions	Excluding Price Revisions
	Three years ended December 31, 2012	
	($/Boe)	
Reserve Replacement Costs	$ 11.88	$ 9.42

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Results of Operations

The information below reflects financial results for EPE Acquisition, LLC (the ultimate holding company prior to the Corporate Reorganization) for the six months ended June 30, 2013 (successor), for the periods from February 14 (inception) to June 30, 2012 (successor) and December 31, 2012 (successor), for the period from January 1 to May 24, 2012 (predecessor) and for the predecessor years ended December 31, 2011 and 2010. Beginning with the Acquisition in May 2012, our successor period 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 our domestic natural gas assets divested in 2013 as discontinued operations. For periods prior to the Acquisition, we have not reflected the domestic natural gas assets divested in 2013 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. As a result, trends and results in future periods are different than those prior to the Acquisition.

The successor, EPE Acquisition, LLC, had no independent oil and gas operations prior to the Acquisition in 2012 and accordingly there were no operational exploration and production activities that changed as a result of the acquisition of the predecessor, Historical EP Energy Corporation. Consequently, in certain period-to-period explanations that follow we have provided supplemental information that compares (i) results for the six months ended June 30, 2013 with results for the successor period from February 14 (inception) to June 30, 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 six months ended June 30, 2012") and (ii) results from the successor period from February 14 (inception) 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 referred to as 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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Year-to-Date Period Ended June 30, 2013 to Year-To-Date Period Ended June 30, 2012

	Year-to-Date Periods		
	2013	2012	
	Successor	Successor	Predecessor
	Six months ended June 30	February 14 (inception) to June 30	January 1 to May 24
Operating revenues:			
Oil and condensate	$ 568	$ 74	$ 322
Natural gas	215	46	262
NGLs	32	4	29
Total physical sales	815	124	613
Financial derivatives	35	57	365
Total operating revenues	850	181	978
Operating expenses:			
Natural gas purchases	10	4	
Transportation costs	46	9	45
Lease operating expense	98	15	96
General and administrative	118	208	75
Depreciation, depletion and amortization	277	26	319
Impairments/Ceiling test charges	10	1	62
Exploration expense	27	6	
Taxes, other than income taxes	43	10	45
Total operating expenses	629	279	642
Operating income (loss)	221	(98)	336
Earnings (loss) from unconsolidated affiliates	6	(1)	(5)
Other (expense) income	(1)	1	(3)
Loss on extinguishment of debt	(3)		
Interest expense	(178)	(53)	(14)
Income (loss) from continuing operations before income tax	45	(151)	314
Income tax expense	2		136
Income (loss) from continuing operations	43	(151)	178
Income from discontinued operations	44	1	
Net income (loss)	$ 87	$ (150)	$ 178

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the six-month period ended June 30, 2013 and for each of the successor and predecessor periods in 2012. 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	
	Successor	Successor	Predecessor
	Six months ended June 30	February 14 (inception) to June 30	January 1 to May 24
Operating revenues(1):			
Oil and condensate	$ 568	$ 74	$ 322
Natural gas	215	46	262
NGLs	32	4	29
Total physical sales	815	124	613
Financial derivatives	35	57	365
Total operating revenues	$ 850	$ 181	$ 978
Volumes(1):			
Oil and condensate			
Consolidated volumes (MBbls)	5,976	905	3,209
Unconsolidated affiliate volumes (MBbls)	136	28	115
Natural gas			
Consolidated volumes (MMcf)	54,351	17,182	99,158
Unconsolidated affiliate volumes (MMcf)	7,317	1,538	6,310
NGLs			
Consolidated volumes (MBbls)	1,098	147	673
Unconsolidated affiliate volumes (MBbls)	229	47	190
Equivalent volumes			
Consolidated MBoe	16,133	3,915	20,408
Unconsolidated affiliate MBoe	1,585	331	1,357
Total combined MBoe	17,718	4,246	21,765
Consolidated MBoe/d	89		
Unconsolidated affiliate MBoe/d	9		
Total Combined MBoe/d	98		
Consolidated prices per unit(2):			
Oil and condensate			
Average realized price on physical sales ($/Bbl)	$ 94.97	$ 82.08	$ 100.44
Average realized price, including financial derivatives ($/Bbl)(3)	$ 101.44	$ 93.80	$ 99.18
Natural gas			
Average realized price on physical sales ($/Mcf)	$ 3.77	$ 2.42	$ 2.64
Average realized price, including financial derivatives ($/Mcf)(3)	$ 3.49	$ 4.48	$ 4.31
NGLs			
Average realized price on physical sales ($/Bbl)	$ 28.68	$ 28.87	$ 42.94

(1) Operating revenues and volumes in the successor periods do not include those revenues and volumes associated with domestic natural gas assets classified as discontinued operations at June 30, 2013.

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(2) Natural gas prices for the six months ended June 30, 2013 and six months ended June 30, 2012 are calculated reflecting a reduction of $16 million and $4 million for natural gas purchases in the applicable period associated with managing our physical sales.

(3) Average realized price, including financial derivatives for successor periods, does not reflect volumes associated with domestic natural gas assets classified as discontinued operations.

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the year to date period in 2013, increases in oil sales were due primarily to oil volume growth from our Eagle Ford drilling program and increases in natural gas prices which more than offset a reduction in natural gas volumes.

Oil and condensate sales for the six months ended June 30, 2013 compared to the combined six months ended June 30, 2012 increased by $172 million (43%), due primarily to oil and volume growth from our Eagle Ford drilling program. In 2013, Eagle Ford production increased by 11 MBbls (or 106%) compared with the year-to-date period ended June 30, 2012.

Natural gas sales for the six months ended June 30, 2013 and successor period from February 14 (inception) to June 30, 2012 were $215 million and $46 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $262 million (including approximately $88 million of natural gas sales related to divested assets). Natural gas sales (excluding amounts related to divested assets) remained relatively flat for the six months ended June 30, 2013 compared with the combined six months ended June 30, 2012, primarily due to an increase in average realized natural gas prices which offset the decrease in volumes due to natural production declines in the Haynesville Shale. During the first quarter of 2012, we suspended our drilling program in the Haynesville Shale due to low natural gas prices.

NGLs sales remained relatively flat for the six months ended June 30, 2013 compared with the combined six months ended June 30, 2012. Average realized prices for the six months ended June 30, 2013 decreased compared to 2012, offset by an increase in NGLs volumes primarily attributable to our Eagle Ford drilling program. Eagle Ford NGLs volumes increased by 3 MBbls/d (or approximately 176%) compared with the year-to-date period ended June 30, 2012.

As of June 30, 2013, the NYMEX spot price of a barrel of oil was $96.56 versus the NYMEX spot price of natural gas of $3.57, a ratio of 27 to 1. We will continue to target increases in our oil volumes in 2013 due to the value of oil in relation to the value of natural gas, 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 with sustained current prices of oil.

Realized and unrealized gains or losses on financial derivatives. We record realized and unrealized gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. During the six months ended June 30, 2013, we recorded $35 million of derivative losses compared to derivative gains of $422 million during the combined six months ended June 30, 2012.

Operating Expenses

Transportation costs. Transportation costs for the six months ended June 30, 2013 and successor period from February 14 (inception) to June 30, 2012 were $46 million and $9 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 divested assets) for the six months ended June 30, 2013 compared to same period in 2012 increased for the six months ended June 30, 2013 due to oil transportation costs associated with our Eagle Ford area as a result of our production growth in that area.

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Lease Operating Expense. Lease operating expense for the six months ended June 30, 2013 and successor period from February 14 (inception) to June 30, 2012 were $98 million and $15 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $96 million (including approximately $31 million related to divested assets). Lease operating expenses for the combined six months ended June 30, 2013 increased over 2012 due to increased equipment and chemical costs in our Eagle Ford area and higher maintenance, repair and power costs.

General and administrative expenses. General and administrative expenses for the six months ended June 30, 2013 decreased $165 million compared to the combined six months ended June 30, 2012. The decrease was primarily due to transition and restructuring costs of $183 million recorded in 2012 as a result of the Acquisition offset by an increase of $10 million in 2013 in management consulting and advisory service charges compared to 2012. Prior to the Acquisition, we were allocated general and administrative costs based on the estimated level of resources devoted to our operations and the relative size of our earnings before interest and taxes, gross property and payroll.

Depreciation, depletion and amortization expense. Our depreciation, depletion and amortization costs increased in 2013 compared with 2012 due to the ongoing development of higher cost oil programs (e.g. Eagle Ford and Wolfcamp). Our average depreciation, depletion and amortization costs per unit for the year-to-date ended June 30 were:

	Year-to-Date Periods		
	2013	**2012**	
	Successor Six months ended June 30	**Successor February 14 (inception) to June 30**	**Predecessor January 1 to May 24**
Depreciation, depletion and amortization ($/Boe)(1)	$ 17.15	$ 6.74	$ 15.62

(1) Includes $0.18 per Boe for the six months ended June 30, 2013, $0.24 per Boe for the successor period from February 14 (inception) to June 30, 2012 and $0.26 for the predecessor period from January 1 to May 24, 2012 related to accretion expense on asset retirement obligations.

Impairments/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. During the six months ended June 30, 2013, we recorded an impairment of approximately $10 million to our oil and natural gas properties in Brazil based on our entry into a Quota Purchase Agreement for these assets in July 2013. 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 natural gas prices from present levels could result in an impairment of the carrying value of our proved properties in the future.

The predecessor used the full cost method of accounting. Under this method of accounting, the predecessor conducted quarterly ceiling tests of capitalized costs in each of the full cost pools. During the predecessor period from January 1, 2012 to May 24, 2012, we recorded non-cash charges of approximately $62 million as a result of our decision to end exploration activities in Egypt. In June 2012, we sold all our interests in Egypt.

Exploration expense. For the six months ended June 30, 2013, we recorded $27 million of exploration expense compared to $6 million for the successor period from February 14 (inception) to June 30, 2012 as a result of applying the successful efforts method of accounting following the Acquisition. Prior to the Acquisition, exploration costs were capitalized under full cost accounting.

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Included in exploration expense for the six months ended June 30, 2013 is $23 million of amortization of unproved property costs.

Taxes, other than income taxes. Taxes, other than income taxes, for the six months ended June 30, 2013 and the successor period from February 14 (inception) to June 30, 2012 were $43 million and $10 million, respectively, and for the predecessor period from January 1 to May 24, 2012 were $45 million (including approximately $9 million of taxes, other than income taxes related to the divested assets). Taxes, other than income taxes, were lower in 2013 compared with 2012 due primarily to recording a reduction in sales and use taxes of $13 million in the second quarter of 2013 associated with settling the remaining Texas sales and use tax audit for $3 million, including penalties and fees.

Cash Operating Costs and Adjusted Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas. Cash operating costs is a non-GAAP measure calculated on a per Boe basis and includes total operating expenses less depreciation, depletion and amortization expense, transportation costs, exploration expense, natural gas purchases, impairments and ceiling test charges and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition and restructuring costs, management fees paid to the Sponsors and non-cash compensation expense. We believe cash operating costs and adjusted cash operating costs per unit are valuable measures of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses for the year-to-date periods below:

	Year-to-Date Periods					
	2013		2012			
	Successor		Successor		Predecessor	
	Six months ended June 30		February 14 (inception) to June 30		January 1 to May 24	
	Total	Per Unit(1)	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)					
Total continuing operating expenses	$ 629	$ 38.96	$ 279	$ 71.25	$ 642	$ 31.48
Depreciation, depletion and amortization	(277)	(17.15)	(26)	(6.74)	(319)	(15.62)
Transportation costs	(46)	(2.83)	(9)	(2.36)	(45)	(2.22)
Exploration expense	(27)	(1.69)	(6)	(1.38)		
Natural gas purchases	(10)	(0.63)	(4)	(1.03)		
Impairments/Ceiling test charges	(10)	(0.61)	(1)	(0.26)	(62)	(3.02)
Total continuing cash operating costs	259	16.05	233	59.48	216	10.62
Transition/restructuring costs and non-cash compensation expense(2)	(35)	(2.19)	(192)	(48.99)	(11)	(0.56)
Total adjusted cash operating costs and adjusted per-unit cash costs(2)	$ 224	$ 13.86	$ 41	$ 10.49	$ 205	$ 10.06
Total equivalent volumes (MBoe)(3)	16,133		3,915		20,408	

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

(2) The six months ended June 30, 2013 includes $8 million of severance costs, $13 million of management fees paid to our Sponsors, and $14 million of non-cash compensation expense. The period from February 14 (inception) to June 30, 2012 includes $178 million of transition and severance costs, $2 million of management fees paid to Sponsors and $11 million of non-cash compensation expense. The period from January 1 to May 24, 2012 includes $5 million of severance costs and $6 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	
	Successor Six months ended June 30	Successor February 14 (inception) to June 30	Predecessor January 1 to May 24
Average cash operating costs ($/Boe)			
Lease operating expenses	$ 6.07	$ 3.86	$ 4.70
Production taxes(1)	3.17	2.11	1.97
General and administrative expenses	7.31	53.23	3.70
Taxes, other than production and income taxes	(0.50)	0.28	0.25
Total cash operating costs	$ 16.05	$ 59.48	$ 10.62
Transition/restructuring costs and non-cash compensation expense	$ (2.19)	$ (48.99)	$ (0.56)
Total adjusted cash operating costs	$ 13.86	$ 10.49	$ 10.06

(1) Production taxes include ad valorem and severance taxes which increased during the six months ended June 30, 2013 primarily due to higher ad valorem taxes associated with our oil producing areas.

Other Income Statement Items

Interest expense. Interest expense for the six months ended June 30, 2013 increased $111 million compared to the combined six months ended June 30, 2012 primarily due to the issuance of approximately $4.25 billion of debt related to 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 August 2013, we repaid $785 million of amounts outstanding under our RBL Facility using proceeds from recently completed asset divestitures and repaid approximately $500 million under our term loans. We will use a portion of the proceeds from this offering to repay our outstanding Senior PIK Toggle Notes.

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Year Ended December 31, 2012 to Year Ended December 31, 2011 and Year Ended December 31, 2011 to Year Ended December 31, 2010

	Successor	Predecessor		
	February 14 (inception), to December 31, 2012	January 1, to May 24, 2012	Years ended December 31, 2011	Years ended December 31, 2010
	(In millions)			
Operating revenues:				
Oil and condensate	$ 555	$ 322	$ 552	$ 346
Natural gas	278	262	973	974
NGLs	32	29	57	60
Total physical sales	865	613	1,582	1,380
Financial derivatives	(62)	365	284	390
Other			1	19
Total operating revenues	803	978	1,867	1,789
Operating expenses:				
Natural gas purchases	19			
Transportation costs	51	45	85	73
Lease operating expense	96	96	217	193
General and administrative	371	75	201	190
Depreciation, depletion and amortization	217	319	612	477
Impairments/Ceiling test charges	1	62	158	25
Exploration expense	50			
Taxes, other than income taxes	51	45	91	85
Other				15
Total operating expenses	856	642	1,364	1,058
Operating (loss) income	(53)	336	503	731
Loss from unconsolidated affiliates	(1)	(5)	(7)	(7)
Other income (expenses)	3	(3)	(2)	3
Loss on extinguishment of debt	(14)			
Interest expense, net of capitalized interest	(219)	(14)	(12)	(21)
(Loss) income from continuing operations before income tax	(284)	314	482	706
Income tax expense	2	136	220	263
(Loss) income from continuing operations	(286)	178	262	443
Income from discontinued operations	30			
Net (loss) income	$ (256)	$ 178	$ 262	$ 443

Operating Revenues

The table below provides our operating revenues, volumes and prices per unit. We present (i) average realized prices based on physical sales of oil and condensate, natural gas and NGLs as well

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as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received and/or paid during the respective period.

	Year-to-Date Periods			
	Successor	Predecessor		
	February 14 (inception), to December 31, 2012	January 1, to May 24, 2012	Years ended December 31, 2011	2010
	($ in millions)			
Operating revenues(1)				
Oil and condensate	$ 555	$ 322	$ 552	$ 346
Natural gas	278	262	973	974
NGLs	32	29	57	60
Total physical sales	865	613	1,582	1,380
Financial derivatives	(62)	365	284	390
Other			1	19
Total operating revenues	$ 803	$ 978	$ 1,867	$ 1,789
Volumes(1):				
Oil and condensate				
Consolidated volumes (MBbls)	6,198	3,209	6,034	4,747
Unconsolidated affiliate volumes (MBbls)	167	115	306	364
Natural gas				
Consolidated volumes (MMcf)	85,347	99,158	241,083	225,611
Unconsolidated affiliate volumes (MMcf)	9,242	6,310	16,881	17,165
NGLs				
Consolidated volumes (MBbls)	940	673	1,068	1,423
Unconsolidated affiliate volumes (MBbls)	288	190	556	573
Equivalent volumes				
Consolidated MBoe	21,363	20,408	47,283	43,772
Unconsolidated affiliate MBoe	1,995	1,357	3,675	3,798
Total Combined MBoe	23,358	21,765	50,958	47,570
Consolidated MBoe/d			130	120
Unconsolidated affiliate MBoe/d			10	10
Total Combined MBoe/d			140	130
Consolidated prices per unit:				
Oil and condensate				
Average realized price on physical sales ($/Bbl)	$ 89.58	$ 100.44	$ 91.40	$ 72.83
Average realized price, including financial derivatives($/Bbl)(2)(3)	$ 97.50	$ 99.18	$ 90.23	$ 71.13
Natural gas				
Average realized price on physical sales ($/Mcf)	$ 3.04	$ 2.64	$ 4.04	$ 4.32
Average realized price, including financial derivatives($/Mcf)(2)(3)	$ 5.08	$ 4.31	$ 5.34	$ 4.97
NGLs				
Average realized price on physical sales ($/Bbl)	$ 33.83	$ 42.94	$ 53.50	$ 42.38

(1)

Operating revenues and volumes in the successor period do not include those volumes associated with domestic natural gas assets held for sale at June 30, 2013 that were reflected as discontinued operations in that period.

(2)

Amounts reflect settlements on derivative instruments, including cash premiums.

(3)

The successor period from February 14 (inception), to December 31, 2012, includes approximately $175 million and the predecessor period from January 1, to May 24, 2012 includes approximately $165 million and the years ended December 31, 2011 and 2010 include approximately $338 million and $306 million of cash receipts for the settlement of natural gas derivative contracts. The successor period from February 14 (inception), to December 31, 2012 includes approximately $45 million of cash receipts for the settlement of crude oil derivatives contracts. The years ended December 31, 2011 and 2010, include approximately $7 million and $8 million of cash paid for the settlement of crude oil derivative contracts.

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Physical sales. Oil and condensate sales for the combined year ended December 31, 2012 increased over 2011 due primarily to oil volume growth from our Eagle Ford, Wolfcamp and Uinta core areas which were up 11 MBbls/d compared with 2011. In 2011, oil revenues increased over 2010 due to both higher oil prices of $112 million and a 27% increase in consolidated oil production volumes of $94 million. For the years ended December 31, 2012 and 2011 our oil and condensate sales increased 59% and 60%, respectively, from the prior year's physical sales.

Natural gas sales were $278 million for the successor period from February 14 (inception) to December 31, 2012 and $262 million for the predecessor period from January 1, 2012 to May 24, 2012 (including $88 million related to divested assets). Natural gas sales for the predecessor periods in 2011 and 2010 were $973 million and $974 million, respectively, including $397 million and $528 million, respectively, related to divested assets. Natural gas sales (excluding amounts related to divested assets) decreased in 2012 compared with 2011 primarily due to lower natural gas prices. Natural gas sales (excluding amounts related to divested assets) were largely flat comparing 2011 to 2010 as increases in production volumes were offset with lower natural gas prices.

Realized and unrealized gains on financial derivatives. Realized and unrealized gains for the combined year ended December 31, 2012, increased by $19 million compared to 2011 and for the year ended December 31, 2011 decreased by $106 million compared to 2010. We record realized and unrealized gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

Operating Expenses

Transportation costs. Transportation costs were $51 million for the successor period from February 14 (inception) to December 31, 2012 and $45 million for the predecessor period from January 1, 2012 to May 24, 2012 (including $18 million related to divested assets). Transportation costs for the predecessor periods in 2011 and 2010 were $85 million and $73 million, respectively, including $40 million and $44 million, respectively, related to divested assets. Total transportation costs (excluding amounts related to divested assets) in 2012 compared to 2011 increased mainly due to new transportation contracts entered into in 2012 primarily related to our Eagle Ford area in response to growth in that area. Transportation costs (excluding amounts related to divested assets) for the year ended December 31, 2011 increased compared to 2010 primarily due to increased production from the Haynesville area as we expanded that program.

Lease operating expense. Lease operating expense was $96 million for the successor period from February 14 (inception) to December 31, 2012, and $96 million for the predecessor period from January 1, 2012 to May 24, 2012 (including $31 million related to divested assets). Lease operating expense for the predecessor periods in 2011 and 2010 was $217 million and $193 million, including $88 million and $94 million related to divested assets. Lease operating expense (excluding amounts related to divested assets) increased $32 million compared to 2011 due to increased water disposal, equipment and chemical costs in our Eagle Ford area as activity ramped up in that area. Lease operating expenses (excluding amounts related to divested assets) for the year ended December 31, 2011 increased compared to 2010 due to higher maintenance, repair and power costs in our Uinta Basin area, higher costs in our Eagle Ford area due to early well testing and higher expenses in our International area.

General and administrative expenses. General and administrative expenses for the combined year ended December 31, 2012 increased $245 million compared to 2011 primarily due to transition and restructuring costs of $221 million incurred in 2012. The costs include acquisition related costs of $173 million and transition and severance costs of $48 million. General and administrative expenses for the year ended December 31, 2011 increased $11 million compared to 2010 due to severance costs related to an office closure and higher employee benefit costs.

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Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the year ended December 31, 2012 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. For the year ended December 31, 2011 depreciation, depletion and amortization increased compared to 2010 as a result of higher depletion rates (due to focusing on our capital on oil programs) under the full cost method of accounting and higher production volumes compared to 2010. Our average depreciation, depletion and amortization costs per unit for the periods ended December 31, 2012, 2011 and 2010 were:

	Successor February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Predecessor Year Ended December 31, 2011	Year Ended December 31, 2010
Depreciation, depletion and amortization ($/MBoe)(1)	$ 10.15	$ 15.62	$ 12.96	$ 10.90

(1) Includes $0.19 per Boe, $0.26 per Boe, $0.27 per Boe and $0.37 per Boe for the periods from February 14 (inception) to December 31, 2012, the period from January 1 to May 24, 2012, and the years ended December 31, 2011 and 2010, respectively, related to accretion expense on asset retirement obligations.

Exploration expense. During the period from February 14 (inception) to December 31, 2012 we recorded $50 million of exploration expense as a result of applying the successful efforts method of accounting following the Acquisition. Prior to the Acquisition, exploration expense was capitalized under full cost accounting. Included in exploration expense was $23 million of amortization of unproved property costs.

Impairments/Ceiling test charges. During 2012 we recorded a non-cash charge of approximately $62 million as a result of our decision to end exploration activities in Egypt. In June of 2012, we sold all our interests in Egypt. During the year ended December 31, 2011 we recorded a non-cash charge of approximately $152 million related to our Brazil oil and natural gas operations and a $6 million impairment of certain oil field related equipment and supplies.

Taxes, other than income taxes. Taxes, other than income taxes, were $51 million for the successor period from February 14 (inception) to December 31, 2012, and $45 million for the predecessor period from January 1, 2012 to May 24, 2012 (including $9 million related to divested assets). Taxes, other than income taxes for the predecessor periods in 2011 and 2010 include $36 million in both periods related to divested assets. For the year ended December 31, 2012, taxes, other than income taxes (excluding amounts related to divested assets), increased $32 million 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. Production taxes for the year ended December 31, 2011 compared to 2010 also increased due to higher oil production volumes.

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Cash Operating Costs and Adjusted Cash Operating Costs. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses:

	Successor		Predecessor					
	February 14 (inception) to December 31, 2012		January 1 to May 24, 2012		Year ended December 31, 2011		Year ended December 31, 2010	
	(In millions, except per unit costs)							
	Total	Per Unit	Total	Per Unit(1)	Total	Per Unit(1)	Total	Per Unit(1)
Total operating expenses	$ 856	$ 40.07	$ 642	$ 31.48	$ 1,364	$ 28.85	$ 1,058	$ 24.17
Depreciation, depletion and amortization	(217)	(10.16)	(319)	(15.62)	(612)	(12.94)	(477)	(10.90)
Transportation costs	(51)	(2.40)	(45)	(2.22)	(85)	(1.79)	(73)	(1.67)
Exploration expense	(50)	(2.33)						
Natural gas purchases	(19)	(0.91)						
Impairments/Ceiling test charges	(1)	(0.05)	(62)	(3.02)	(158)	(3.36)	(25)	(0.58)
Other							(15)	(0.34)
Total cash operating costs and per-unit cash costs	518	24.22	216	10.62	509	10.76	468	10.68
Transition/restructuring costs and non-cash compensation expense(2)	(266)	(12.44)	(11)	(0.56)	(27)	(0.56)	(18)	(0.40)
Total adjusted cash operating costs and adjusted per-unit cash costs	$ 252	$ 11.78	$ 205	$ 10.06	$ 482	$ 10.20	$ 450	$ 10.28
Total equivalent volumes (MBoe)(3)	21,363		20,408		47,283		43,772	

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

(2) 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. The year ended December 31, 2010 includes $18 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:

	Successor	Predecessor		
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011	Year ended December 31, 2010
Average cash operating costs ($/Boe)				
Lease operating expenses	$ 4.50	$ 4.70	$ 4.59	$ 4.42
Production taxes(1)	2.17	1.97	1.71	1.60
General and administrative expenses	17.35	3.70	4.24	4.34
Taxes, other than production and income taxes	0.20	0.25	0.22	0.32
Total cash operating costs	$ 24.22	$ 10.62	$ 10.76	$ 10.68
Transition/restructuring costs and non-cash compensation expense	$ (12.44)	$ (0.56)	$ (0.56)	$ (0.40)
Total adjusted cash operating costs	$ 11.78	$ 10.06	$ 10.20	$ 10.28

(1) Production taxes include ad valorem and severance taxes which increased in 2012 primarily due to higher severance and ad valorem taxes associated with our oil producing areas.

Other Income Statement Items

Loss on extinguishment of debt. For the successor period 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 combined year ended December 31, 2012 increased compared to 2011 primarily due to the issuance of approximately $4.25 billion of debt in 2012 related to the Acquisition.

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, net of cash settlements and premiums related to these derivatives), impairment and/or ceiling test charges, adjustments to reflect cash distributions of the earnings from our unconsolidated affiliates, non-cash compensation expense, non-recurring transition and restructuring costs, advisory fees paid to our sponsors, losses or gains on extinguishment of debt and losses or gains on sale of assets. 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

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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		
				Years ended December 31,	
	Six months ended, June 30, 2013	February 14 (inception), to December 31, 2012	January 1 to May 24, 2012	2011	2010
			(in millions)		
Income (loss) from continuing operations	$ 43	$ (286)	$ 178	$ 262	$ 443
Income tax expense	2	2	136	220	263
Interest expense, net of capitalized interest	178	219	14	12	21
Depreciation, depletion and amortization	277	217	319	612	477
Exploration expense	27	50			
EBITDAX	527	202	647	1,106	1,204
Net impact of financial derivatives(a)	(12)	285	(200)	47	(99)
Impairments/ceiling test charges	10	1	62	158	25
Transition and restructuring costs(b)	8	215	5	6	
Dividends from unconsolidated affiliate(c)	17	13	8	46	50
(Income) loss from unconsolidated affiliate(d)	(6)	1	5	7	7
Non-cash compensation expense(e)	14	35	6	21	18
Management fee(f)	13	16			
Loss on extinguishment of debt(g)	3	14			
Adjusted EBITDAX	574	782	533	1,391	1,205
Less: Adjusted EBITDAX divested assets(h)	11	31	75	559	700
Pro Forma Adjusted EBITDAX	$ 563	$ 751	$ 458	$ 832	$ 505

(a) Represents the non-cash net change in the fair value of derivatives, net of actual cash settlements received/(paid) related to these derivatives, including any related cash premiums.

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

(c) Represents cash dividends received from Four Star, our unconsolidated affiliate in which we hold an approximate 49% equity interest.

(d) Reflects the elimination of non-cash 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.

(e)

Represents the non-cash portion of compensation expense.

(f)

Represents the pro-rata portion of the annual management fee to be paid to affiliates of the Sponsors and other investors. The annual management fee of $25 million will terminate in connection with the closing of this offering.

(g)

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

(h)

Consists of Adjusted EBITDAX contributions related to assets that have been or are in the process of being divested, including our (i) Brazil operations, (ii) CBM, South Texas and Arklatex assets, (iii) Gulf of Mexico assets, (iv) Blue Creek West, Minden and Powder River operations and (v) Catapult operations and Altamont processing plant and related gathering systems.

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Liquidity and Capital Resources

Overview. 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. As of June 30, 2013, our available liquidity was approximately $2.0 billion, including approximately $1.7 billion of additional borrowing capacity available under the RBL Facility. In August 2013, we completed our semi-annual redetermination, maintaining the borrowing base of our RBL Facility at $2.5 billion.

During June 2013, we entered into three separate purchase and sale agreements for the sale of our CBM properties (Raton, Arkoma and Black Warrior basins), the majority of our Arklatex natural gas properties and our natural gas properties in South Texas. In July and August we completed these asset divestitures receiving total consideration of approximately $1.3 billion. We will experience lower cash flow from operations than originally planned as a result of these asset divestitures initially, but used the proceeds, among other items, to pay down debt and invest incremental capital in our core oil programs to generate higher oil production growth and expand our financial returns.

As of June 30, 2013, our total debt was approximately $5.4 billion, comprised of $3.1 billion in senior notes due in 2019, 2020 and 2022, $1.15 billion in senior secured term loans with maturity dates in 2018 and 2019, $785 million outstanding under the RBL Facility expiring in 2017 and $365 million in Senior PIK toggle notes due December 2017. While our debt and interest expense is significantly higher than in predecessor periods due to debt incurred with the Acquisition, we have repaid approximately $785 million of amounts outstanding under our RBL Facility with proceeds from our asset divestitures in July and August 2013. We also repaid approximately $500 million under our term loans. Additionally, we anticipate utilizing a portion of the proceeds from this offering (i) to redeem all of the outstanding 8.125%/8.875% Senior PIK Toggle Notes due 2017 issued by our subsidiaries, EPE Holdings LLC and EP Energy Bondco Inc., and pay the redemption premium and the accrued and unpaid interest on the notes, (ii) to repay outstanding borrowings under the RBL Facility, (iii) to pay an approximately $ million fee under the transaction fee agreement with certain affiliates of our Sponsors and (iv) for general corporate purposes. See "Use of Proceeds." Where favorable debt markets allow, we also evaluate opportunities to reduce our interest cost. In May 2013, we repriced our $750 million term loan due 2018 that reduced the specified margin over LIBOR from 4.00% to 2.75%, and reduced the minimum LIBOR floor from 1.00% to 0.75% over the remaining life of the term loan. In August 2013, we distributed $200 million to our Sponsors. For additional details on our debt, see "Capitalization" and Note 7 to our historical consolidated financial statements and related notes included elsewhere in this prospectus.

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 for the foreseeable future. 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 (e.g. by entering into oil and natural gas derivative contracts to reduce the financial impact of downward commodity price movements on a substantial portion of our anticipated production), but we could be required to take additional future actions if necessary to address further changes in the financial or commodity markets.

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

	Successor			Predecessor		
	Six months ended June 30, 2013	February 14 (inception) to June 30, 2012	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	December 31, 2011	December 31, 2010
Cash Flow from Operations						
Operating activities						
Net (loss) income	$ 87	$ (150)	$ (256)	$ 178	$ 262	$ 443
Impairments	10	1	1			
Ceiling test charges				62	158	25
Other income adjustments	381	48	351	537	973	859
Change in other assets and liabilities	(28)	9	353	(197)	33	(260)
Total cash flow from operations	$ 450	$ (92)	$ 449	$ 580	$ 1,426	$ 1,067
Other Cash Inflows						
Investing activities						
Net proceeds from the sale of assets	$ 10	$ 22	$ 110	$ 9	$ 612	$ 155
Other						4
	10	22	110	9	612	159
Financing activities						
Proceeds from debt	985	4,323	5,825	215	2,030	500
Contributions		3,300	3,323	960		
Net change in note payable with parent						489
	985	7,623	9,148	1,175	2,030	989
Total cash inflows	$ 995	$ 7,645	$ 9,258	$ 1,184	$ 2,642	$ 1,148
Cash Outflows						
Investing activities						
Capital expenditures	$ 914	$ 150	$ 877	$ 636	$ 1,591	$ 1,238
Cash paid for acquisitions	2	7,126	7,126	1	22	51
Increase in note receivable with parent					236	
	916	7,276	8,003	637	1,849	1,289
Financing activities						
Repayment of debt	305	80	1,139	1,065	1,480	1,034
Net change in note payable with parent company and affiliates					781	
Member distribution	5		337			
Debt issuance costs	5	142	159		7	1
	315	222	1,635	1,065	2,268	1,035
Total cash outflows	$ 1,231	$ 7,498	$ 9,638	$ 1,702	$ 4,117	$ 2,324

Net change in cash and cash equivalents	$	214	$	55	$	69	$	62	$	(49)	$	(109)

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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 June 30, 2013, for each of the periods presented:

	2013	2014 - 2015	2016 - 2017	Thereafter	Total
			(In millions)		
Long-term financing obligations:					
Principal	$	$	$ 1,323	$ 4,250	$ 5,573
Interest	166	666	652	667	2,151
Liabilities from derivatives	5	2			7
Operating leases	7	26	21		54
Other contractual commitments and purchase obligations:					
Volume and transportation commitments(1)	54	180	169	284	687
Other obligations	48	79	55	159	341
Total contractual obligations	$ 280	$ 953	$ 2,220	$ 5,360	$ 8,813

(1) Includes a total of approximately $25 million of volume and transportation commitments related to divested assets.

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 August 2013, we repaid $785 million outstanding under our RBL Facility and $500 million under our term loans. Additionally, we anticipate using a portion of the proceeds from this offering to repay our outstanding senior PIK toggle notes.

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

Operating Leases. We maintain 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 and storage capacity.

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. We are also party to a management fee agreement requiring an annual management fee of $25 million to be paid to our Sponsors. The management fee agreement will be terminated at the closing of this offering.

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Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Note 8 to our historical consolidated financial statements and related notes included elsewhere in this prospectus.

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, an effect on our financial condition or results of operations.

Critical Accounting Estimates

Our significant accounting policies are described in Note 1 to our historical consolidated financial statements and related notes included elsewhere in this prospectus. 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 properties. Under the successful efforts method, exploratory non-drilling costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred while acquisition costs, development costs and the costs associated with drilling exploratory wells are capitalized pending the determination of proved oil and gas reserves. Therefore, at any point in time, we may have capitalized costs on our consolidated balance sheet associated with exploratory wells that could 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 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 review our oil and natural gas properties periodically (at least annually) to determine if impairment of such properties is necessary. Significant proved undeveloped leasehold costs are assessed for impairment at a field level or resource play based on total future undiscounted net cash flows. Estimates of future undiscounted cash flows require significant judgment based on estimates of such items as estimates of oil and natural gas reserve quantities, future commodity prices, operating costs and future production among other factors. Leasehold acquisition costs associated with prospective areas that have limited or no previous exploratory drilling are generally 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. Proved oil and natural gas property values are reviewed when circumstances suggest the need for such a review and may occur if a field discovers lower than anticipated reserves, reservoirs produce below original estimates or in a mix that is different than anticipated or if commodity prices fall below 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. 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. From the Acquisition (May 25, 2012) to December 31, 3012, we did not record any impairments of our oil and gas properties. For the six months ended June 30, 2013, we recorded a $10 million impairment based on comparing the fair market value of our Brazil operations to their underlying carrying value.

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, regardless of whether reserves were actually discovered. 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. Prior to the Acquisition, our predecessor recorded ceiling test charges of $62 million, $152 million, $25 million and $2,123 million for the period from January 1, 2012 through May 24, 2012 and for the years ended 2011, 2010, and 2009, 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 test charges on our income statements, among other items. The process of estimating oil and natural gas reserves is complex and requires significant judgment to evaluate all available geological, geophysical engineering and economic data. Our proved reserves are estimated at a property level and compiled for reporting purposes by a centralized group of experienced reservoir engineers who work closely with the operating groups. These engineers interact with engineering and geoscience personnel in each of our operating areas and accounting and marketing personnel to obtain the necessary data for projecting future production, costs, net revenues and economic recoverable reserves. Reserves are reviewed internally with senior management quarterly and presented to the board of managers 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 managers, conducts an audit of the estimates of a significant portion of our proved reserves.

As of June 30, 2013, 65% of our total consolidated proved reserves were undeveloped (61% including Four Star) and 5% 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 June 30, 2013, our net asset retirement liability was approximately $86 million of which $37 million is related to our Brazil operations, which we expect to have sold by the end of the first quarter of 2014.

Derivatives. We record the derivative instruments used in our derivative activities 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 June 30, 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)	$ 179	$ (158)	$ (337)	$ 504	$ 325

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

Deferred Taxes and Uncertain Income Tax Positions. Subsequent to the Corporate Reorganization, we will record deferred income tax assets and liabilities reflecting tax consequences deferred to future periods based on differences between the financial statement carrying value of assets and liabilities and the tax basis of assets and liabilities. Additionally, our deferred tax assets and liabilities will reflect our assessment of tax positions taken, and the resulting tax basis, and 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 will include, but are not limited to, the realization of our deferred tax assets, uncertain tax positions, and undistributed earnings of our unconsolidated subsidiary which involve the exercise of significant judgment which could change and impact our financial condition or results of operations.

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 held; 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.

Where practical, we manage these 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 Notes 1 and 5 to our consolidated financial statements included elsewhere in this prospectus.

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 price risk management activities to changes in fair values arising from immediate selected potential changes in oil and natural gas prices, discount rates and credit rates at June 30, 2013:

	Oil and Natural Gas Derivative Instruments				
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
		(in millions)			
Price impact(1)	$ 179	$ (158)	$ (337)	$ 504	$ 325

	Oil and Natural Gas Derivative Instruments				
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
		(in millions)			
Discount rate(2)	$ 179	$ 176	$ (3)	$ 182	$ 3
Credit rate(3)	$ 179	$ 177	$ (2)	$ 180	$ 1

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

(2) Presents the hypothetical sensitivity of our commodity-based derivative instruments 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 derivative instruments 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 interest-bearing debt by expected maturity date as well as the total fair value of the debt. The fair value of our debt has been estimated primarily based on quoted market prices for the same or similar issues.

	June 30, 2013								December 31, 2012	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
						(in millions)				
Fixed rate debt	$	$	$	$	$ 538	$ 3,100	$ 3,638	$ 3,805	$ 3,449	$ 3,779
Average interest rate	8.6%	8.6%	8.6%	8.6%	8.6%	8.4%				
Variable rate debt	$	$	$	$	$ 785	$ 1,141	$ 1,926	$ 1,925	$ 1,246	$ 1,260
Average interest rate	3.5%	3.5%	3.5%	3.5%	3.6%	4.5%				

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BUSINESS

Overview

We are an independent exploration and production company engaged in the acquisition and development of unconventional onshore oil and natural gas properties in the United States. We are focused on creating shareholder value through the development of our low-risk drilling inventory located in four core areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas), the Uinta Basin (Utah) and the Haynesville Shale (North Louisiana). In our core areas, we have identified in excess of 5,200 drilling locations, of which approximately 96% are oil wells. At current activity levels, this represents approximately 24 years of drilling inventory. As of June 30, 2013, we had domestic proved reserves of 501 MMBoe (57% oil and 66% liquids) and for the three months ended June 30, 2013, we had average net daily domestic production of 93,674 Boe/d (37% oil and 46% liquids).

Our management team has a proven track record of identifying, acquiring and developing unconventional oil and natural gas assets. The majority of our senior management team has worked together for over a decade and the team has significant experience at prominent oil and gas companies that have included El Paso Corporation, ConocoPhillips and Burlington Resources. We believe our management's experience in both acquiring resource-rich leasehold positions and efficiently developing those properties will enable us to generate attractive rates of return from our capital programs.

Each of our core areas is characterized by a favorable operating environment, long-lived reserve base and high drilling success rates. We have established significant contiguous leasehold positions in each area, representing approximately 450,000 net (620,000 gross) acres in total. Beginning in 2012, our capital programs have focused predominantly on the Eagle Ford Shale, the Wolfcamp Shale and the Uinta Basin, three of the premier unconventional oil plays in the United States, resulting in oil reserve and production growth of 47% and 88%, respectively, from December 31, 2011 to December 31, 2012. In July and August 2013, we divested non-core natural gas assets for a total consideration of approximately $1.3 billion. Additionally, in July 2013, we entered into a Quota Purchase Agreement relating to the sale of our Brazil operations, which is expected to close by the end of the first quarter of 2014. As a result of this strategic repositioning, 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 in the future to this natural gas-weighted asset.

The following table provides a summary of oil, natural gas and NGLs reserve and production information for each of our areas of operation as of June 30, 2013. Our estimated proved reserves have

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been prepared by our internal reserve engineers and audited by Ryder Scott Company, L.P., our independent petroleum engineering consultants since 2004.

Estimated Proved Reserves

	Oil (MMBbls)	NGL (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Liquids (%)	Proved Developed (%)	PV-10(1) Value ($MM)	% of Total (%)	Average Net Daily Production(2) (MBoe/d)	R/P (Years)(3)
Core Areas										
Eagle Ford Shale	167.7	27.3	217.4	231.2	84%	22%	4,084	55%	34.9	18.1
Wolfcamp Shale	43.4	8.6	58.3	61.7	84%	22%	711	10%	4.4	38.6
Uinta Basin	71.9		148.4	96.6	74%	35%	1,765	24%	11.4	23.2
Haynesville Shale			373.1	62.2	0%	69%	430	6%	29.0	5.9
Total Core Areas	**283.1**	**35.8**	**797.2**	**451.7**	**71%**	**31%**	**6,991**	**95%**	**79.7**	**15.5**
Other(4)	2.0	1.0	71.7	14.9	20%	83%	135	2%	5.3	7.7
Total Consolidated	**285.0**	**36.8**	**868.9**	**466.7**	**69%**	**33%**	**7,126**	**97%**	**85.0**	**15.0**
Four Star	2.1	6.2	155.9	34.3	24%	93%	260	3%	8.7	10.8
Total Combined	**287.2**	**43.0**	**1,024.8**	**501.0**	**66%**	**37%**	**7,386**	**100%**	**93.7**	**14.7**

(1) PV-10 is a non-GAAP measure and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. To determine PV-10 we used SEC pricing, including the unweighted arithmetic average of the historical first-day-of-the-month prices for the prior 12 months, which were $91.60 per barrel of oil and $3.44 per MMBtu of natural gas as of June 30, 2013. Please see " Summary Operating and Reserve Information."

(2) Represents the three months ended June 30, 2013.

(3) Calculated as total proved reserves divided by the annualized Average Net Daily Production for the three months ended June 30, 2013.

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

Approximately 186 MMBoe, or 37%, of our total combined proved reserves are proved developed assets, which for the three months ended June 30, 2013 generated average production of 93,674 Boed from approximately 1,275 wells. As of June 30, 2013, we had 287 MMBbls of proved oil reserves, 43 MMBbls of proved NGLs reserves and 1,025 Bcf of proved natural gas reserves in the United States, representing 57%, 9% and 34%, respectively, of our total proved reserves. For the six months ended June 30, 2013, 73% of our revenues (excluding realized and unrealized gains on financial derivatives) were related to oil and NGLs versus 58% during the same period in 2012, and over that same period and on that same basis, our oil production has grown by approximately 60%. As a result of our development program and recently completed divestitures, the oil-weighting of our reserves is 57% as of June 30, 2013 as compared to 42% as of December 31, 2012 without giving effect to the recently completed divestitures. In 2013, we anticipate that approximately 95% of our capital expenditures will be allocated to our core oil programs.

We operate over 83% of our producing wells and have operational control over approximately 95% of our core area drilling inventory as of June 30, 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 the first six months of 2013, we drilled 105 wells with a success rate of 99%, adding approximately 65 MMBoe of proved reserves as compared to December 31, 2012. The reserve replacement cost was $17.67 per Boe, excluding price revisions, 79% of which was oil. Please see "Management's Discussion and Analysis of Financial Condition and Results of Operations Reserve Replacement Ratio/Reserve Replacement Costs."

Our Properties and 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, having produced over 750 MMBoe since 2008, including approximately 348 MMBoe in 2012. We were an early entrant into this play in late 2008, and since that

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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), which results in some of the most prolific acreage in the area. 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. We currently have 97,689 net (105,416 gross) acres in the Eagle Ford, in which we have identified 983 drilling locations.

For the three months ended June 30, 2013, our average net daily production was 34,944 Boe/d, representing growth of 115% over the same period in 2012. As of June 30, 2013, we had five rigs running and plan to drill 126 wells in 2013 (of which 67 have been drilled through June 30, 2013), representing 58% of our total wells planned in 2013. For the six months ended June 30, 2013 our average cost per well was $7.5 million, representing an 11% decline from our average cost per well for the same period in 2012. We expect our average cost per well to continue to decline.

Wolfcamp Shale. The Wolfcamp Shale is located in the Permian Basin, which has produced more than 29 billion barrels of oil and 75 Tcf of gas over the past 90 years and is estimated by industry experts to contain recoverable oil and natural gas reserves exceeding what has already been produced. With oil production of over 880 MBbls/d from over 80,000 wells during the six months ended June 30, 2013, the Permian Basin represented 51% of the crude oil produced in the State of Texas and approximately 17% of the crude oil and condensate produced onshore in the lower 48 United States. The basin is characterized by numerous, stacked oil reservoirs that provide excellent targets for horizontal drilling. We are currently targeting the Wolfcamp Shale in the Southern Midland Basin, where industry horizontal drilling has added over 50 MBoe/d to the basin's production since 2010.

In 2009 and 2010, we leased 138,130 net (138,468 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. Following our drilling results in 2012, we moved forward to full development of the Wolfcamp B, and began delineation of the Wolfcamp C. Our initial 30-day oil equivalent production rates are up to 600 Boe/d for the Wolfcamp B. As of June 30, 2013, we have identified 2,938 drilling locations in the Wolfcamp A, the Wolfcamp B and the Wolfcamp C across our acreage. 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 to test this development approach.

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.

For the three months ended June 30, 2013, our average net daily production was 4,382 Boe/d, representing growth of 152% over the same period in 2012. As of June 30, 2013, we had three rigs running and plan to drill 65 wells in 2013 (of which 25 have been drilled through June 30, 2013), representing 30% of our total wells planned in 2013. For the six months ended June 30, 2013 our average cost per well was $5.9 million, representing a 24% decline from our average cost per well for the same period in 2012. Similar to the Eagle Ford Shale, we expect our average costs per well to continue to decline.

Uinta Basin. The Uinta Basin, located in northeastern Utah, has produced 577 MMbbls since its discovery in 1949 and is characterized by naturally fractured, tight oil sands with multiple zones. Our operations are primarily focused on developing the Altamont Field (including the Bluebell and Cedar Rim fields), which is the largest field in the basin. We own 172,293 net (318,568 gross) acres in

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Duchesne and Uinta Counties, making us the largest lease owner in the Altamont Field. Since their discovery, the Altamont, Bluebell and Cedar Rim fields have produced a combined total of over 300 MMBbls from the oil-rich Wasatch and Green River sandstones. With gross thicknesses over 4,300 feet across multiple sandstone and carbonate intervals, 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 900 Boe/d. Our current activity is mainly focused on the development of our vertical inventory on 160-acre spacing. We have identified an inventory of 1,104 drilling locations (758 vertical and 346 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 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.

For the three months ended June 30, 2013, our average net daily production was 11,433 Boe/d, representing growth of 14% over the same period in 2012. As of June 30, 2013, we had two rigs running and plan to drill 26 wells in 2013 (of which 13 have been drilled as of June 30, 2013), representing 12% of our total wells planned in 2013. For the six months ended June 30, 2013 our average cost per well was $5.2 million, representing a 13% decline from our average cost per well for the same period in 2012.

Haynesville Shale. In addition to our key 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. This area is within the core of the Haynesville Shale with net thickness of 114 feet (210 feet gross), resulting in initial 30-day gas equivalent production rates up to 18 MMcfe/d. We currently have 40,029 net (59,210 gross) acres in this area. As of June 30, 2013, we have identified 190 drilling locations.

For the three months ended June 30, 2013, our average net daily production was 174 MMcfe/d. As of June 30, 2013, we had 191 producing wells, which provide cash flow to fund the development of our core oil programs. We do not plan to drill any new wells in the Haynesville in 2013. 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.

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The following table provides a summary of acreage and inventory data for our core areas, as of June 30, 2013:

Core Acreage and Inventory Summary as of June 30, 2013

	Acres		Drilling Locations(1) (#)	2013 Drilling Locations(2) (#)	Inventory (Years)(3)	Working Interest (%)	Net Revenue Interest (%)
	Gross	Net					
Core Areas							
Eagle Ford Shale	105,416	97,689	983	126	7.8	90%	67%
Wolfcamp Shale	138,468	138,130	2,938	65	45.2	96%	72%
Wolfcamp A			1,001			96%	72%
Wolfcamp B			939			96%	72%
Wolfcamp C			998			96%	72%
Uinta Basin	318,568	172,293	1,104	26	42.5	72%	60%
Vertical			758			72%	61%
Horizontal			346			69%	58%
Haynesville Shale	59,210	40,029	190		NA	78%	62%
Holly			97			81%	67%
Non-Holly			93			74%	57%
Total Core Areas	**621,662**	**448,141**	**5,215**	**217**	**24.0**	**89%**	**68%**

(1) Our inventory as of June 30, 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 the Uinta Basin, (i) vertical infill locations and (ii) horizontal drilling locations in the Wasatch and Green River formations.

(2) Represents gross operated wells to be completed in 2013.

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

Our 5,215 low-risk drilling locations across our core areas, of which 96% are oil wells, provide us with over 24 years of drilling inventory. We have used the data from our development programs to identify and prioritize our inventory. These drilling locations are only included in our inventory after they have been evaluated technically.

Other Oil and Natural Gas Properties and Assets

We have other producing assets that contribute cash flow toward the development of our oil-focused core areas. During the first six months of 2013, we invested an aggregate of $6 million in capital expenditures in the following areas:

South Louisiana Wilcox. In our South Louisiana Wilcox area we control 67,706 total net (74,344 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, which have recently traded at premium levels relative to the WTI index.

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During most of 2012, we operated one drilling rig in South Louisiana Wilcox. In the fourth quarter of 2012, we idled drilling activity to allow completion of a regional model based on our well results and seismic data. For the six months ended June 30, 2013 we had average daily production of 1.7 MBoe/d and as of that date we had 22 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 six months ended June 30, 2013, we had average daily production of 3.6 MBoe/d and as of that date we had 274 net producing wells.

Unconsolidated Affiliate Four Star Oil & Gas Company ("Four Star"). We have an approximate 49% equity interest in Four Star. Four Star operates primarily in the San Juan, Permian, Hugoton and South Alabama basins. Production is from conventional and CBM assets in several basins. For the six months ended June 30, 2013, our equity interest in Four Star's daily equivalent production averaged approximately 8.7 MBoe/d.

Brazil. Our Brazilian assets consist of producing fields along with exploration and development projects offshore Brazil. Our Brazilian operations are in the Camamu, Espirito Santo and Potiguar basins covering approximately 111,000 net acres. For the six months ended June 30, 2013, we invested less than $1 million of capital expenditures in Brazil and averaged 4.7 MBoe/d of production. We have agreed to sell all of our Brazil operations. See " Recent Divestitures."

Recent Divestitures

During the third quarter of 2013, we sold certain of our natural gas properties, including our CBM properties (Raton, Arkoma and Black Warrior Basin), the majority of our Arklatex natural gas properties and our natural gas properties in South Texas, in three separate transactions. The total consideration was approximately $1.3 billion, and proceeds were used to repay outstanding borrowings under the RBL Facility and to fund capital expenditures.

Additionally, in July 2013, certain of our subsidiaries entered into a Quota Purchase Agreement relating to the sale of all of our Brazil operations. Pursuant to the Quota Purchase Agreement, the subsidiaries have agreed to sell all of our equity interests in two Brazilian subsidiaries to a third party. The transaction is expected to close by the end of the first quarter of 2014, subject to Brazilian regulatory approval and certain other customary closing conditions.

Business Strategy

We are a high-growth, 100% onshore U.S., oil-weighted company with a large inventory of high-return, low-risk drilling locations. We are focused on creating shareholder value by implementing the following strategies:

Grow Oil Production, Cash Flow and Reserves through the Development of our Extensive Drilling Inventory

We have assembled a drilling inventory of over 5,200 drilling locations across approximately 450,000 net (620,000 gross) acres in the Eagle Ford Shale, the Wolfcamp Shale, the Uinta Basin and the Haynesville Shale. The concentration and scale of our core leasehold positions, coupled with our technical understanding of the reservoirs, should allow us to efficiently develop our core areas and allocate capital to maximize the value of our resource base. In 2012, we invested $1.5 billion (92% in

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our core oil areas) of capital expenditures and grew domestic oil production by 11,511 Bbls/d, or 88%, from an average of 13,042 Bbls/d in 2011 to an average of 24,553 Bbls/d in 2012. Pro Forma Adjusted EBITDAX increased by 46% from 2011 to 2012. We also increased domestic proved oil reserves by 82 MMBbls, or 47%, from 175 MMBbls at December 31, 2011 to 257 MMBbls at December 31, 2012. In 2013, we plan to invest approximately $1.9 billion of capital expenditures, of which 95% is dedicated to developing our core oil areas. For the six months ended June 30, 2013, $937 million of capital expenditures had been spent. We believe that our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, cash flow and reserve growth and create shareholder value. We consider our inventory of drilling locations to be low risk because those locations were selected based on our (and the industry's) extensive drilling and production experience and success in the relevant areas. For additional information regarding Adjusted EBITDAX, please read "Management's Discussion and Analysis of Financial Condition and Results of Operations Supplemental Non-GAAP Measures."

Maintain an Extensive Low-Risk Drilling Inventory

We have a demonstrated track record of identifying and cost effectively acquiring low-risk resource development opportunities. We follow a geologically driven strategy to establish large, contiguous leasehold positions in the core of prolific basins and opportunistically add to those positions through bolt-on acquisitions over time. We were an early entrant into the Eagle Ford and Wolfcamp Shales through grassroots leasing efforts, amassing average positions of over 100,000 net acres, and we methodically expanded our position in the Uinta Basin through targeted acquisitions. We will continue to identify and opportunistically acquire additional acreage and producing assets to add to our multi-year drilling inventory.

Enhance Returns by Continuously Improving Capital and Operating Efficiencies

We maintain a disciplined, returns-focused approach to capital allocation. Our large and diverse portfolio of drilling locations allows us to conduct cost-efficient operations and allocate capital to our highest-margin assets in a variety of commodity price environments. We continuously monitor and adjust our development program in order to maximize the value of our extensive portfolio of drilling opportunities. In each of our core areas, we have realized improvements in EURs while delivering reductions in drilling and completion costs since 2011. We have reduced our average cost per well in the Wolfcamp by 40%, Eagle Ford by 24% and Uinta Basin by 22% from 2011 through the first half of 2013. The cost reductions to date have been due to many improvements, including substantial reductions in cycle times and successful negotiations for supplies and services. We expect further cost reductions going forward due to additional learning and efficiencies, including drilling wells from common pad sites, shared use of pre-existing central facilities and other economies of scale.

Identify and Develop Additional Drilling Opportunities in our Portfolio

Our existing asset base provides numerous opportunities for our highly experienced technical team to create shareholder value by increasing our inventory beyond our currently identified drilling locations. In the Permian Basin, we have evaluated multiple Wolfcamp horizons, and we are currently running pilot delineation programs in the Wolfcamp A and C horizons. Additionally, this acreage is prospective for the Cline Shale, the Spraberry and other stacked formations. The Uinta Basin has a significant inventory of low-risk, vertical infill drilling locations and is also currently being assessed for additional horizontal development potential in multiple shale and tight sands intervals. Our primary focus in the Eagle Ford is increasing incremental returns through a reduction in drilling and completion costs. Our 3-D seismic programs in the Uinta and Permian Basins should further enhance our ability to increase the number of and high grade our drilling locations.

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Maintain Liquidity and Financial Flexibility

We intend to fund our organic growth predominantly with internally generated cash flows while maintaining ample liquidity. We will continue to maintain a disciplined approach to spending whereby we allocate capital in order to optimize returns and create shareholder value. Upon completion of this offering, we will have $2.5 billion available for borrowing under the RBL Facility. As we pursue our strategy of developing high-return opportunities in our core areas, we expect our cash flow and borrowing base to grow, thereby further enhancing our liquidity and financial strength. We protect these future cash flows and liquidity levels by maintaining a three year rolling hedge program. In general, we target hedging levels of over 50% of expected production on a rolling three year basis.

Competitive Strengths

We believe the following strengths provide us with significant competitive advantages:

Large, Concentrated Operated Positions in the Core Areas of Prolific Oil Resource Plays

We own and operate contiguous leasehold positions in the core areas of three of the premier North American oil resource plays: the Eagle Ford Shale, the Wolfcamp Shale and the Uinta Basin. We have approximately 410,000 net (560,000 gross) acres across these three plays that we have substantially de-risked through our ongoing drilling programs. Since 2010, we have drilled and completed 338 wells across these three plays with a success rate of approximately 99%. Based on our analysis of subsurface data and the production history of our wells and those of offset operators, we have confirmed high quality reservoir characteristics across a broad aerial extent with significant hydrocarbon resources in place. Based upon our well costs and production rates, we believe our core oil areas offer some of the best single well rates of return of all North American resource plays.

Multi-Year Inventory of Low-Risk Drilling Opportunities

Our 5,215 low-risk drilling locations across our core areas as of June 30, 2013 provide us with approximately 24 years of drilling inventory, of which 96% are oil wells. We have used the subsurface data from our development programs to identify and prioritize our inventory. These drilling locations are included in our inventory after they have passed through a rigorous technical evaluation. In addition to our 5,215 identified drilling locations, we believe we have the potential to increase our multi-year drilling inventory with horizontal drilling locations in the Cline Shale and vertical drilling locations in the Spraberry and other stacked formations in the Permian Basin, and vertical infill and horizontal drilling locations in the Wasatch and Green River formations in the Uinta Basin. Our ongoing technical assessment and development activities provide the potential for identification of additional drilling opportunities on our properties. A portion of this acreage is also prospective for the Cline Shale. In the Uinta Basin, we have potential for additional vertical infill drilling locations.

High-Quality Proved Reserve Base with Substantial Current Production

Our leasehold position and inventory of low-risk drilling locations is complemented by a substantial proved reserve base. As of June 30, 2013, we had domestic proved reserves of 501 MMBoe (57% oil and 66% liquids) with a PV-10 of $7.4 billion (86% oil and 91% liquids). For the three months ended June 30, 2013, our average domestic net daily production was 93,674 Boe/d, which was 37% oil and 46% liquids. Our current production provides a stable source of cash flow to fund the development of our core programs. This significantly reduces our reliance on outside sources of capital. In addition, our extensive inventory improves our ability to replace and grow proved reserves.

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Significant Operational Control with Low Cost Operations

Our significant operational control permits us to efficiently manage the amount and timing of our capital outflows, allowing us to continually improve our drilling and operating practices. We operate over 83% of our producing wells and have operational control of approximately 95% of our core area drilling inventory as of June 30, 2013. We employ a centralized operational structure to accelerate our internal knowledge transfer between our drilling and completion programs and to continually enhance our field operations and base production performance. We have decreased our average cost per well by 24%, 11% and 13% in the Wolfcamp Shale, Eagle Ford Shale and Uinta Basin, respectively, for the six months ended June 30, 2013, compared to our average cost per well for the same period in 2012.

Capital Allocation Flexibility and Scale across Multiple Basins

Our existing assets are geographically diversified among many of the major basins of North America, which helps to insulate us from regional commodity pricing and cost dislocations that occur from time to time. While our existing producing assets are well diversified, they are also of a critical mass (on average over 100,000 net acres in each core area), which enables us to drive efficiencies and benefit from economies of scale across multiple basins. Furthermore, because of our centralized operational structure, we are able to quickly transfer operational efficiencies from one project to the next. From January 1, 2008 to June 30, 2013, we have drilled 386 horizontal shale wells. From this deep operational knowledge base and sizeable, concentrated positions in multiple basins, we have the flexibility to allocate significant amounts of capital across our properties in an efficient and value-maximizing manner.

Ability to Direct Capital to the Prolific Haynesville Shale

The Haynesville Shale is a key asset for us and is likely to compete for development capital if natural gas prices improve. Because our operations are surrounded by existing infrastructure, future returns are primarily driven by drilling and completion costs and natural gas prices. Since our Haynesville wells have demonstrated high initial production rates and strong EURs, small movements in natural gas prices can drive significant incremental value creation. Since these leases are held-by-production, we have the ability to redirect capital to this prolific asset in the future.

Significant Liquidity and Financial Flexibility

Upon completion of this offering, we will have $2.5 billion available for borrowing under our RBL Facility. We maintain a robust hedging program in order to protect our cash flows through commodity cycles. As of August 2, 2013, our hedged volumes for 2013, 2014, 2015 and 2016 represent 89%, 83%, 61% and 6%, respectively, based on our total equivalent domestic production for the three months ended June 30, 2013. After the completion of this offering, we expect that liquidity provided by operating cash flow, availability under the RBL Facility and available cash will give us the financial flexibility to pursue our planned capital expenditures for the foreseeable future.

Experienced Management Team with Proven Track Record

With an average of 24 years of experience, our senior management team has a strong track record built at El Paso Corporation and in former leadership roles with Burlington Resources, ConocoPhillips and other leading energy companies. The majority of our senior management team has worked together for over a decade and has significant experience in identifying, acquiring and developing unconventional oil and natural gas assets, including experience in horizontal drilling and developing shales. Through a combination of invested equity and incentive programs, we believe our management is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

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2013 Capital Budget

We have a projected 2013 capital program of approximately $1.9 billion. Our capital program will remain focused on continuing to grow production, cash flows, and reserves in our highest return oil programs. In particular, the Eagle Ford currently generates the highest returns in our portfolio and, as a result we are investing the majority of our capital in this program. We expect that liquidity provided by operating cash flow, availability under the RBL Facility and available cash will be sufficient to fund the 2013 capital plan.

	2013 Capital Program						Six months ended June 30, 2013	
($ in Millions)	**Drilling & Completion**	**Facilities & Other**	**Total**	**% of Total**	**Active Rigs(2)**	**2013 Drilling Locations(3)**	**Capital Expenditures**	**Gross Wells Drilled**
Core Areas								
Eagle Ford Shale	$ 897	$ 221	$ 1,118	58%	5	126	$ 600	67
Wolfcamp Shale	447	54	501	26%	3	65	236	25
Uinta Basin	137	58	195	10%	2	26	94	13
Haynesville Shale		1	1	0%			1	
Total Core Areas	**$ 1,481**	**$ 334**	**$ 1,815**	**95%**	**10**	**217**	**$ 931**	**105**
Other(1)	14	85	99	5%		1	6	
Total	**$ 1,495**	**$ 419**	**$ 1,914**	**100%**	**10**	**218**	**$ 937**	**105**

(1) Consists of South Louisiana Wilcox and Arklatex Tight Gas and approximately $70 million of capitalized general and administrative, interest and other costs.

(2) Active Rigs as of June 30, 2013.

(3) Represents gross operated wells to be completed in 2013.

In the beginning of the year, we projected a 2013 capital program of approximately $1.7 billion. Based on the results of the first half of the year and the results of our asset divestitures, we increased our 2013 capital program by up to $175 million for incremental drilling and completion activity. This incremental capital has added 36 wells to the original budget of 182 wells to be drilled and completed this year.

2013 Capital Budget
$1.9 Billion(1)

2013 Drilling Locations
218 Locations(2)

(1) Includes approximately $70 million of capitalized interest, information technology and capitalized direct labor costs.

(2) Represents gross operated wells to be completed in 2013.

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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 proved reserves as of June 30, 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 "Risk Factors." Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at June 30, 2013.

	Net Proved Reserves as of June 30, 2013				
	Oil (MMBbls)	NGL (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	Percent (%)
Reserves by Classification					
Consolidated:					
Domestic					
Proved Developed					
Core Areas					
Eagle Ford Shale	35.2	7.0	56.6	51.5	10%
Wolfcamp Shale	9.2	1.9	13.2	13.3	3%
Uinta Basin	25.1		54.9	34.4	7%
Haynesville Shale			257.0	42.8	8%
Total Core Areas	69.5	8.9	381.7	142.0	28%
Other	1.2	0.4	64.5	12.3	2%
Total Proved Developed(1)	70.7	9.3	446.2	154.3	30%
Proved Undeveloped					
Core Areas					
Eagle Ford Shale	132.6	20.3	160.8	179.7	35%
Wolfcamp Shale	34.3	6.6	45.2	48.4	9%
Uinta Basin	46.7		93.4	62.4	12%
Haynesville Shale			116.1	19.3	4%
Total Core Areas	213.6	26.9	415.5	309.8	60%
Other	0.7	0.6	7.2	2.6	1%
Total Proved Undeveloped	214.3	27.5	422.7	312.4	61%
Total Consolidated Domestic	285.0	36.8	868.9	466.7	91%
Unconsolidated Affiliate(2)					
Proved Developed	2.2	5.5	145.4	31.8	6%
Proved Undeveloped		0.7	10.5	2.5	1%
Total Unconsolidated Affiliate(2)	2.2	6.2	155.9	34.3	7%
Total Combined Domestic	287.2	43.0	1,024.8	501.0	98%
Brazil(3)					
Proved Developed	2.0		63.2	12.5	2%

Proved Undeveloped					0%
Total Brazil	2.0		63.2	12.5	2%
Total Combined Worldwide	289.2	43.0	1,088.0	513.5	100%

(1) Includes 137 MMBoe of proved developed producing reserves representing 29% of consolidated proved reserves and 18 MMBoe of proved developed non-producing reserves representing 4% of consolidated proved reserves at June 30, 2013.

(2) Represents our approximate 49% equity interest in Four Star.

(3) We have entered into an agreement to sell these operations. See "Recent Divestitures."

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Our consolidated 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 proved reserves were prepared by our internal reserve engineers and audited by Ryder Scott Company, L.P., our independent petroleum engineering consultants since 2004.

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

Our primary internal technical person in charge of overseeing our reserves estimates, including the reserves estimate we prepare related to our investment in Four Star, 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 "Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Estimates."

Ryder Scott conducted an audit of the estimates of the proved reserves that we prepared as of June 30, 2013 for each of our core areas as well as our Arklatex Tight Gas assets. Our estimates of proved reserves for our South Louisiana Wilcox assets, Four Star and the natural gas assets that we divested as described in " Recent Divestitures" were not included in the Ryder Scott audit. In connection with its audit, Ryder Scott reviewed 70% (by volume) of our total proved reserves on a barrel of oil equivalent basis, representing 86% of the total discounted future net cash flows of these proved reserves (before giving effect to our pending and recently completed divestitures). For the reviewed properties, 91% of our total PUD reserves (before giving effect to our pending and recently completed divestitures) were evaluated. Ryder Scott concluded the overall procedures and methodologies that we utilized in preparing our estimates of proved reserves as of June 30, 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 SPE auditing standards.

Although Ryder Scott did not conduct a mid-year 2013 audit of Four Star, they did review these properties in 2012. As of December 31, 2012, Ryder Scott reviewed 85% (by value) of Four Star total proved reserves on a natural gas equivalent basis, representing 92% of the total discounted future net cash flows of these proved reserves. For the Four Star properties, 100% of our total PUD reserves were evaluated and Ryder Scott concluded the overall procedures and methodologies that we utilized in preparing our estimates of proved reserves as of December 31, 2012 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 SPE auditing standards.

Ryder Scott's reports are included as exhibits to the registration statement of which this prospectus forms a part.

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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 nine 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.

Proved Undeveloped Reserves (PUDs)

As of June 30, 2013, we have 630 net PUD locations, of which 619 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 June 30, 2013, we had 312 MMBoe of consolidated PUD reserves, representing an increase of 19 MMBoe of PUD reserves compared to December 31, 2012, excluding sales related to our recent divestitures of 22 MMBoe of PUD reserves. During the six months ended June 30, 2013, we added 47 MMBoe of PUD reserves primarily from our drilling activities in the Eagle Ford Shale and the Wolfcamp Shale, we had 19 MMBoe of PUD reserves transferred to proved developed reserves and negative revisions of 9 MMBoe primarily due to forecast updates. As of June 30, 2013, we had no PUD reserves associated with our Brazil assets.

We spent approximately $370 million, $587 million and $601 million, during the first six months of 2013, and for the entirety of 2012 and 2011, respectively, to convert approximately 6% or 19 MMBoe, 10% or 32 MMBoe and 17% or 35 MMBoe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our June 30, 2013 internal reserve report, the amounts estimated to be spent in 2013, 2014 and 2015 to develop our consolidated worldwide PUD reserves are $591 million, $1,042 million and $1,156 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 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 312 MMBoe of consolidated PUD reserves at June 30, 2013, none are scheduled to remain undeveloped beyond five years.

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The following table summarizes our changes in consolidated PUDs during 2012 and the last six months ended June 30, 2013 (in MMBoe):

Balance, December 31, 2011	320
Purchase of minerals-in-place	131
Extensions and discoveries	0
Revisions of previous estimates(1)	(103)
Transfers to proved developed	(32)
Divestitures	(1)
Balance, December 31, 2012	**315**
Purchase of minerals-in-place	0
Extensions and discoveries	47
Revisions of previous estimates	(9)
Transfers to proved developed	(19)
Divestitures	(22)
Balance, June 30, 2013	**312**

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

Acreage and Wells

The following tables detail (i) our interest in developed and undeveloped acreage at June 30, 2013, (ii) our interest in oil and natural gas wells at June 30, 2013 and (iii) our exploratory and development wells drilled during the six months ended June 30, 2013 and years 2010 through 2012. 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	14,959	14,070	90,457	83,619	105,416	97,689
Wolfcamp Shale	7,398	7,398	131,070	130,732	138,468	138,130
Uinta Basin	138,830	115,824	179,738	56,469	318,568	172,293
Haynesville Shale	35,844	28,306	23,366	11,723	59,210	40,029
Total Core Areas	197,031	165,598	424,631	282,543	621,662	448,141
Other	127,604	28,607	468,091	326,112	595,695	354,719
Total Acreage Domestic	324,635	194,205	892,722	608,655	1,217,357	802,860
Brazil(3)	47,377	14,492	398,732	96,418	446,109	110,910
Total Acreage Worldwide	372,012	208,697	1,291,454	705,073	1,663,466	913,770

(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)

We have entered into an agreement to sell these operations. See "Recent Divestitures."

Our net developed acreage is concentrated primarily in Texas (14%), Louisiana (24%), and Utah (58%). Our net undeveloped acreage is concentrated primarily in Texas (37%), Louisiana (10%), and Utah (10%). Approximately 5%, 6% and 8% of our net undeveloped acreage is held under leases

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that have minimum remaining primary terms expiring in 2013, 2014 and 2015, 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.

	Natural Gas		Oil		Total		Wells Being Drilled at June 30, 2013(1)	
	Gross(2)(3)	Net(4)	Gross(2)	Net(4)	Gross(2)	Net(4)(5)	Gross(2)	Net(4)
Productive Wells								
Core Areas								
Eagle Ford Shale	3	3	211	201	214	204	24	22
Wolfcamp Shale			56	56	56	56	29	26
Uinta Basin	3	1	418	325	421	326	8	3
Haynesville Shale	191	106			191	106		
Total Core Areas	197	110	685	582	882	692	61	51
Other	387	291	5	5	392	296		
Total Productive Wells Domestic	584	401	690	587	1,274	988	61	51
Brazil(6)	12	4	2	1	14	5		
Total Productive Wells Worldwide	596	405	692	588	1,288	993	61	51

(1) Comprised of wells that were spud as of June 30, 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 June 30, 2013, we operated 973 of the 993 net productive wells.

(6) We have entered into an agreement to sell these operations. See "Recent Divestitures."

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	Net Exploratory(1)				Net Development(1)			
	Six months ended June 30,	Year ended December 31,			Six months ended June 30,	Year ended December 31,		
	2013	2012	2011	2010	2013	2012	2011	2010
Wells Drilled								
Core Areas								
Productive	6	13	73	28	92	116	57	46
Dry		1			1	2		
Total Core Areas	6	14	73	28	93	118	57	46
Other Domestic								
Productive		7	9			5	2	
Dry						1		
Total Other Domestic		7	9			6	2	
Divested Assets(2)								
Productive			5	7		11	36	9
Dry								2
Total Divested Assets			5	7		11	36	11
Consolidated Domestic								
Productive	6	20	87	35	92	132	95	55
Dry		1			1	3		2
Total Domestic	6	21	87	35	93	135	95	57
Brazil								
Productive								
Dry			1					
Total Brazil			1					
Total Worldwide								
Productive	6	20	87	35	92	132	95	55
Dry		1	1		1	3		2
Total Worldwide	6	21	88	35	93	135	95	57

(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, 2011 and 2010 include those for our CBM, South Texas and Arklatex assets, each sold in 2013 and of our Gulf of Mexico assets sold in 2012. See " Recent Divestitures."

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, average sales prices received, average transportation costs, average lease operating expense and average production taxes associated with the sale of oil and natural gas for the periods indicated:

	Six months ended June 30,		Year ended December 31,		
	2013	**2012**	**2012**	**2011**	**2010**
Volumes:					
Consolidated Net Production Volumes					
Core Areas					
Oil and Condensate (MBbls)	5,718	3,428	8,277	4,220	2,451
Natural Gas (MMcf)	45,324	64,557	122,254	105,429	57,479
NGL (MBbls)	1,032	361	1,056	216	38
Total Core Areas (MMBoe)	14,304	14,548	29,709	22,008	12,069
Other Domestic					
Oil and Condensate (MBbls)	161	218	427	234	129
Natural Gas (MMcf)	4,538	7,384	12,603	14,440	18,652
NGL (MBbls)	66	155	245	22	60
Total Other (MMBoe)	984	1,604	2,772	2,662	3,298
Total Domestic Continuing					
Oil and Condensate (MBbls)	5,879	3,646	8,704	4,454	2,580
Natural Gas (MMcf)	49,862	71,941	134,857	119,869	76,131
NGL (MBbls)	1,098	516	1,301	238	98
Total Domestic(MMBoe)	15,288	16,152	32,481	24,670	15,367
Divested Assets					
Oil and Condensate (MBbls)		281	297	1,226	1,783
Natural Gas (MMcf)		39,019	39,419	110,800	139,774
NGL (MBbls)		304	312	830	1,325
Total (MMBoe)		7,088	7,179	20,523	26,403
Consolidated Domestic					
Oil and Condensate (MBbls)	5,879	3,927	9,001	5,680	4,363
Natural Gas (MMcf)	49,862	110,960	174,276	230,669	215,905
NGL (MBbls)	1,098	820	1,613	1,068	1,423
Total (MMBoe)	15,288	23,240	39,660	45,193	41,770
MBoe/d	*84.4*	*127.7*	*108.4*	*123.8*	*114.4*
Unconsolidated Affiliate(1)					
Oil and Condensate (MBbls)	136	143	282	306	364
Natural Gas (MMcf)	7,317	7,848	15,552	16,881	17,165
NGL (MBbls)	229	237	478	556	573
Total (MMBoe)	1,585	1,688	3,352	3,675	3,798
MBoe/d	*8.8*	*9.3*	*9.2*	*10.1*	*10.4*
Total Combined Volumes Domestic					
Oil and Condensate (MBbls)	6,015	4,070	9,283	5,986	4,727
Natural Gas (MMcf)	57,179	118,808	189,828	247,550	233,070
NGL (MBbls)	1,327	1,057	2,091	1,624	1,996
Total Equivalent Volumes (MMBoe)	16,873	24,927	43,012	48,868	45,568
MBoe/d	*93.2*	*137.0*	*117.6*	*133.9*	*124.8*

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	Six months ended June 30,		Year ended December 31,		
	2013	2012	2012	2011	2010
Brazil					
Oil and Condensate (MBbls)	97	187	406	354	384
Natural Gas (MMcf)	4,489	5,380	10,230	10,414	9,706
NGL (MBbls)					
Total Brazil (MMBoe)	845	1,084	2,111	2,090	2,002
MBoe/d	*4.7*	*6.0*	*5.8*	*5.7*	*5.5*
Total Combined Volumes Worldwide					
Oil and Condensate (MBbls)	6,112	4,257	9,689	6,340	5,111
Natural Gas (MMcf)	61,668	124,188	200,058	257,964	242,776
NGL (MBbls)	1,327	1,057	2,091	1,624	1,996
Total Equivalent Volumes (MMBoe)	17,718	26,011	45,123	50,958	47,570
MBoe/d	*97.9*	*143.0*	*123.4*	*139.6*	*130.3*

(1) Represents our approximate 49% equity interest in the volumes of Four Star.

	Six months ended June 30,		Year ended December 31,		
	2013	2012	2012	2011	2010
Eagle Ford Shale					
Oil and Condensate (MBbls)	3,849	1,882	5,023	1,702	177
Natural Gas (MMcf)	7,135	3,251	8,425	3,094	947
NGL (MBbls)	929	338	936	207	30
Total Eagle Ford Shale (MMBoe)	5,967	2,762	7,364	2,425	366
Wolfcamp Shale					
Oil and Condensate (MBbls)	403	209	489	132	
Natural Gas (MMcf)	692	391	763	212	
NGL (MBbls)	99	21	116		
Total Wolfcamp Shale (MMBoe)	617	295	734	168	
Uinta Basin					
Oil and Condensate (MBbls)	1,466	1,337	2,765	2,385	2,273
Natural Gas (MMcf)	3,332	3,262	6,632	5,677	4,915
NGL (MBbls)	4	2	4	7	5
Total Uinta Basin (MMBoe)	2,026	1,884	3,876	3,338	3,097
Haynesville Shale					
Oil and Condensate (MBbls)				1	1
Natural Gas (MMcf)	34,165	57,653	106,434	96,446	51,617
NGL (MBbls)				2	3
Total Haynesville Shale (MMBoe)	5,694	9,608	17,736	16,077	8,606

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	Six months ended June 30,		Year ended December 31,		
	2013	2012	2012	2011	2010
Consolidated Prices and Costs per Unit:					
Oil and Condensate Average Realized Sales Price ($/Bbl)					
Consolidated Domestic					
Physical Sales	$ 94.81	$ 95.83	$ 92.58	$ 90.22	$ 72.37
Including Financial Derivatives(1)	$ 101.39	$ 97.51	$ 97.19	$ 88.98	$ 70.52
Brazil					
Physical Sales	$ 104.39	$ 108.30	$ 108.81	$ 110.33	$ 78.02
Including Financial Derivatives(1)	$ 104.39	$ 108.30	$ 108.81	$ 110.33	$ 78.02
Total Consolidated Worldwide					
Physical Sales	$ 94.96	$ 96.40	$ 93.28	$ 91.40	$ 72.83
Including Financial Derivatives(1)	$ 101.44	$ 98.00	$ 97.69	$ 90.23	$ 71.13
Natural Gas Average Realized Sales Price ($/Mcf)					
Consolidated Domestic					
Physical Sales	$ 3.42	$ 2.36	$ 2.54	$ 3.91	$ 4.26
Including Financial Derivatives(1)	$ 3.12	$ 4.17	$ 4.49	$ 5.37	$ 5.71
Brazil					
Physical Sales	$ 7.65	$ 7.77	$ 7.66	$ 6.94	$ 5.65
Including Financial Derivatives(1)	$ 7.65	$ 7.77	$ 7.66	$ 6.94	$ 4.93
Total Consolidated Worldwide					
Physical Sales	$ 3.77	$ 2.61	$ 2.82	$ 4.04	$ 4.32
Including Financial Derivatives(1)	$ 3.49	$ 4.34	$ 4.66	$ 5.44	$ 5.67
NGL Average Realized Sales Price ($/Bbl)					
Consolidated Domestic					
Physical Sales	$ 28.68	$ 40.42	$ 37.63	$ 53.50	$ 42.38
Brazil					
Physical Sales	$	$	$	$	$
Total Consolidated Worldwide					
Physical Sales	$ 28.68	$ 40.42	$ 37.63	$ 53.50	$ 42.38

(1) Amounts reflect settlements on derivative instruments, including cash premiums.

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	Six months ended June 30, 2013	Six months ended June 30, 2012	Year ended December 31, 2012	Year ended December 31, 2011	Year ended December 31, 2010
Average Transportation Costs					
Core Areas					
Oil and Condensate ($/Bbl)	$ 2.13	$ 1.46	$ 2.09	$ 0.05	$ 0.04
Natural Gas ($/Mcf)	$ 0.55	$ 0.37	$ 0.40	$ 0.34	$ 0.27
NGL ($/Bbl)	$ 4.97	$ 3.92	$ 2.93	$ 1.12	$ 7.66
Other Domestic					
Oil and Condensate ($/Bbl)	$ 0.01	$ 0.03	$ 0.02	$ 0.02	$ 0.37
Natural Gas ($/Mcf)	$ 0.66	$ 0.45	$ 0.46	$ 0.39	$ 0.34
NGL ($/Bbl)	$ 7.52	$ 10.41	$ 9.32	$ 11.46	$ 8.30
Divested Assets					
Oil and Condensate ($/Bbl)	$	$ 0.14	$ 0.17	$ 0.13	$ 0.14
Natural Gas ($/Mcf)	$	$ 0.43	$ 0.43	$ 0.35	$ 0.33
NGL ($/Bbl)	$	$ 6.94	$ 6.82	$ 4.33	$ 2.79
Consolidated Domestic					
Oil and Condensate ($/Bbl)	$ 2.07	$ 1.29	$ 1.93	$ 0.06	$ 0.09
Natural Gas ($/Mcf)	$ 0.56	$ 0.40	$ 0.41	$ 0.35	$ 0.31
NGL ($/Bbl)	$ 5.13	$ 6.27	$ 4.65	$ 3.83	$ 3.16
Brazil(1)					
Oil and Condensate ($/Bbl)	$	$	$	$	$
Natural Gas ($/Mcf)	$	$	$	$	$
NGL ($/Bbl)	$	$	$	$	$
Total Consolidated Worldwide					
Oil and Condensate ($/Bbl)	$ 2.04	$ 1.23	$ 1.85	$ 0.06	$ 0.08
Natural Gas ($/Mcf)	$ 0.51	$ 0.38	$ 0.39	$ 0.33	$ 0.30
NGL ($/Bbl)	$ 5.13	$ 6.27	$ 4.65	$ 3.83	$ 3.16
Average Lease Operating Expenses ($/Boe)					
Core Areas	$ 4.98	$ 3.10	$ 3.26	$ 2.53	$ 2.87
Other	$ 7.07	$ 4.66	$ 5.33	$ 5.17	$ 3.15
Divested Assets	$	$ 5.49	$ 5.44	$ 5.19	$ 4.23
Total Consolidated Domestic	$ 5.11	$ 3.94	$ 3.80	$ 3.89	$ 3.75
Brazil(1)	$ 23.43	$ 18.86	$ 19.62	$ 19.77	$ 18.43
Total Consolidated Worldwide	$ 6.07	$ 4.60	$ 4.60	$ 4.59	$ 4.42
Average Production Taxes ($/Boe)					
Core Areas	$ 2.93	$ 1.93	$ 1.93	$ 1.25	$ 1.21
Other	$ 4.21	$ 3.54	$ 3.30	$ 2.50	$ 3.50
Divested Assets	$	$ 1.19	$ 1.18	$ 1.71	$ 1.33
Total Consolidated Domestic	$ 3.01	$ 1.82	$ 1.89	$ 1.53	$ 1.47
Brazil(1)	$ 5.98	$ 5.73	$ 5.57	$ 5.45	$ 4.39
Total Consolidated Worldwide	$ 3.17	$ 1.99	$ 2.07	$ 1.71	$ 1.60

(1) We have entered into an agreement to sell these properties. See " Recent Divestitures."

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Acquisition, Development and Exploration Expenditures

The following table details information regarding the capital expenditures in our acquisition, development and exploration activities for the periods indicated:

	Successor		Predecessor		
($ in millions)	Six months ended June 30, 2013	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011	Year ended December 31, 2010
Core Areas					
Acquisition Costs:					
Proved	$ 2	$	$	$	$ 49
Unproved	10	7	31	24	177
Development Costs	864	768	491	577	160
Exploration Costs:					
Delay Rentals		4		6	
Seismic Acquisitions and Reprocessing		20		3	3
Drilling	45	58	37	752	484
Other	1	1			
Asset Retirement Obligations	4	2	8	3	(2)
Total Oil and Natural Gas Expenditures	$ 926	$ 860	$ 567	$ 1,365	$ 871
Non-Oil and Natural Gas Expenditures	4	2	2	6	5
Total Capital Expenditures	$ 930	$ 862	$ 569	$ 1,371	$ 876
Other Domestic					
Acquisition Costs:					
Proved	$	$	$	$	$ 2
Unproved	(2)	12	5	21	14
Development Costs	2	24	17	53	28
Exploration Costs:					
Delay Rentals	1	1		2	2
Seismic Acquisitions and Reprocessing		2	16	28	7
Drilling	2	19	11	57	40
Other	1	2			
Asset Retirement Obligations		8	1	1	1
Total Oil and Natural Gas Expenditures	$ 4	$ 68	$ 50	$ 162	$ 94
Non-Oil and Natural Gas Expenditures	7	12	1	6	18
Total Capital Expenditures	$ 11	$ 80	$ 51	$ 168	$ 112
Total Domestic					
Acquisition Costs:					
Proved	$ 2	$	$	$	$ 51
Unproved	8	19	36	45	191
Development Costs	866	792	508	630	188
Exploration Costs:					
Delay Rentals	1	5		8	2
Seismic Acquisitions and Reprocessing		22	16	31	10
Drilling	47	77	48	809	524
Other	2	3			
Asset Retirement Obligations	4	10	9	4	(1)
Total Oil and Natural Gas Expenditures	$ 930	$ 928	$ 617	$ 1,527	$ 965
Non-Oil and Natural Gas Expenditures	11	14	3	12	23

Total Capital Expenditures	$ 941	$ 942	$ 620	$ 1,539	$ 988
Divested Assets			17	101	250
Total Domestic Capital Expenditures	$ 941	$ 942	$ 637	$ 1,640	$ 1,238

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($ in millions)	Successor Six months ended June 30, 2013	Successor February 14 (inception) to December 31, 2012	Predecessor January 1 to May 24, 2012	Predecessor Year ended December 31, 2011	Predecessor Year ended December 31, 2010
Brazil/Other					
Acquisition Costs:					
Unproved	$	$	$	$	$
Development Costs		4		14	28
Exploration Costs:					
Seismic Acquisitions and Reprocessing		(1)		9	
Drilling				(6)	37
Other		6			
Asset Retirement Obligations		3	10		
Total Oil and Natural Gas Expenditures	$	$ 12	$ 10	$ 17	$ 65
Non-Oil and Natural Gas Expenditures				4	
Total Capital Expenditures	$	$ 12	$ 10	$ 21	$ 65
Divested Assets			3	8	22
Total Brazil/Other Capital Expenditures	$	$	$ 13	$ 29	$ 87
Total Worldwide					
Acquisition Costs:					
Proved	$ 2	$	$	$	$ 51
Unproved	8	19	36	45	191
Development Costs	866	796	508	644	216
Exploration Costs:					
Delay Rentals	1	5		8	2
Seismic Acquisitions and Reprocessing		21	16	40	10
Drilling	47	77	48	803	561
Other	2	9			
Divested Assets(1)			20	109	272
Asset Retirement Obligations	4	13	19	4	(1)
Total Oil and Natural Gas Expenditures	$ 930	$ 940	$ 647	$ 1,653	$ 1,302
Non-Oil and Natural Gas Expenditures	11	14	3	16	23
Total Capital Expenditures	$ 941	$ 954	$ 650	$ 1,669	$ 1,325

(1) Wells of divested assets in 2012, 2011 and 2010 include those for our CBM, South Texas and Arklatex assets, each sold in 2013 and our Gulf of Mexico assets sold in 2012. See " Recent Divestitures."

Operations

As of June 30, 2013, we operated approximately 83% of our producing wells. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Transportation, Markets and Customers

Our physical commodity marketing strategy seeks to ensure both maximum deliverability of our production and maximum realized prices. We leverage our knowledge of markets and transportation infrastructure to enter into optimal 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 six months ended June 30, 2013, three purchasers accounted for approximately 80% of our oil revenues. 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.

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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 50% during July 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 MMcf/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 33% during July 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 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 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 strong 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 both the West Texas Gas and DCP gathering systems, and we process the vast 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. 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 Uinta Basin 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 pioneered a crude-by-rail solution four years ago to expand the market for Uinta Basin wax crude beyond Salt Lake City. We anticipate that planned expansions of Salt Lake City refineries and expanded rail capacity will keep pace with basin-wide production growth, and we continue to develop new market solutions. Our produced natural gas is gathered and processed at 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, Enterprise Stateline Gathering, and Crosstex LIG Pipeline. We currently control 300 MMcf/d of firm capacity on these pipelines, of which we used an average of 80% during July 2013. Currently, our Haynesville Shale

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gas is produced at close to pipeline specifications and requires only CO_2 removal before delivery into takeaway pipelines. We sell our physical gas production to a wide variety of purchasers at spot market prices under short-term sales agreements. Given the abundance of pipeline infrastructure in the region and the growing demand for natural gas in the southeast, we do not anticipate any issues with production deliverability.

While most of our physical production is priced off spot market indices, we actively manage the volatility of spot market pricing through a dynamic and 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 over 1,500 square miles of 3-D seismic data. We have 435 square miles of 3-D seismic data in our four core areas which provides approximately 30% coverage 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

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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 six months ended June 30, 2013, we incurred costs of approximately $235 million associated with hydraulic fracturing.

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

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

- Conductor casing is drilled and cemented or driven in place. This string serves as the structural foundation for the well. Conductor casing is not necessary or required for all wells.

- Surface casing is set and is cemented in place. Surface casing is set on all wells. The purpose of the surface casing is to isolate and protect Underground Sources of Drinking Water ("USDW") as identified by federal and state regulatory bodies. The surface casing and cement isolates wellbore materials from any potential contact with USDWs.

- Intermediate casing is set through the surface casing to a depth necessary to isolate abnormally pressured subsurface formations from normally pressured formations. Intermediate casing is not necessary or required for all wells. Our standard practices include cementing above any hydrocarbon bearing zone and performing casing pressure tests to verify the integrity of the casing and cement.

- Production casing is set through the surface and intermediate casing through the depth of the targeted producing formation. Our standard practices include pumping cement above the confining structure of the target zone and performing casing pressure tests and other tests to verify the integrity of the casing and cement. If any problems are detected, then appropriate remedial action is taken.

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With the casing set and cemented, a barrier of steel and cement is in place that is designed to isolate the wellbore from surrounding geologic formations. This barrier as designed mitigates against the risk of drilling or fracturing fluids entering potential sources of drinking water.

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

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

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

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

Environmental

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and GHG emissions. Numerous governmental agencies, such as the EPA, issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses

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and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

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 June 30, 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.

Climate Change and Other Emissions. 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 purports to regulate 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. 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. More recently, 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 other industries, such as the March 2012 proposed GHG rule restricting future development of coal-fired power plants. 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

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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.

Restrictions on GHG emissions that may be imposed in various states could adversely affect the oil and natural gas industry. Any GHG regulation could 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. While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

Air Quality Regulations. The Clean Air Act ("CAA") and comparable state laws and regulations regulate emissions of various air pollutants through the issuance of permits and the imposition of other requirements. The EPA has developed, and continues to develop, stringent regulations governing emissions of air pollutants at specified sources. New facilities may be required to obtain permits before work can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. In August 2010, the EPA finalized a rule that impacts emissions of hazardous air pollutants from reciprocating internal combustion engines and requires us to install emission controls on engines across our operations. Engines subject to the regulations have to be in compliance by October 2013. On August 16, 2012, EPA published regulations in the Federal Register pursuant to the federal Clean Air Act to reduce various air pollutants from the oil and natural gas industry, which are discussed in more detail in " Hydraulic Fracturing Regulations." At this time, we estimate less than $1 million in 2013 capital expenditures to meet these requirements.

In 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 anticipate installation of tank emission controls. At this time, we estimate that we will incur capital expenditures of approximately $2 million in 2013 and 2014 related to the installation of these controls.

Hydraulic Fracturing Regulations. 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 SDWA regulates the underground injection of substances through the 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 U.S. Department of the Interior published a revised proposed rule on May 16, 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 is presently subject to an extended 90-day public comment period, which ends on August 23, 2013.

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

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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. Further, 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. Congress has considered legislation in recent legislative sessions 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 CAA that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA promulgated New Source Performance Standards establishing emission limits for sulfur dioxide (SO2) and volatile organic compounds (VOCs). The final rule requires a 95% reduction in VOCs emitted by mandating the use of reduced emission completions or "green completions" on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. The rules also establish new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. In response to numerous requests for reconsideration of these rules from both industry and the environmental community and court challenges to the final rules, the EPA announced its intention to issue revised rules in 2013. The EPA revised portions of these rules on August 2, 2013 (awaiting Federal Register publication) for VOCs emissions for production oil and gas storage tanks. The final revised rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

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 in June 2011, 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 a "well integrity rule," which updates the requirements for drilling, putting pipe down, and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The "well integrity rule" takes 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.

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.

Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA") Matters. The Comprehensive Environmental Response, Compensation and Liability Act, as amended, also known as the "Superfund" law, and analogous state laws, generally imposes strict and joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current owner or operator of a contaminated facility, a former owner or operator of the facility at the time of contamination, and those persons that disposed or arranged for the disposal of the hazardous substance at the facility. Under CERCLA and comparable state statutes, persons deemed "responsible parties" may be subject to strict and joint and several liability for the costs of removing or remediating previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination), for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. 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 June 30, 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 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 environmental reserve discussed above.

Waste Handling. The Resource Conservation and Recovery Act, as amended, ("RCRA") and comparable state statutes and regulations promulgated thereunder, affect oil and natural gas exploration, development and production activities by imposing requirements regarding the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. With federal approval, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Although most wastes associated with the exploration, development and production of crude oil and natural gas are exempt from regulation as hazardous wastes under RCRA, such wastes may constitute "solid wastes" that are subject to the less stringent requirements of non-hazardous waste provisions. However, we cannot assure you that the EPA or state or local governments will not adopt more stringent requirements for the handling of non-hazardous wastes or categorize some non-hazardous wastes as hazardous for future regulation. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and natural gas exploration, development and production wastes as "hazardous wastes." Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water Discharges. The Federal Water Pollution Control Act of 1972, as amended, also known as the CWA, the SDWA, the Oil Pollution Act (the "OPA") and analogous state laws and regulations promulgated thereunder impose restrictions and strict controls regarding the unauthorized discharge of pollutants, including produced waters and other gas and oil wastes, into navigable waters of the United States, as well as state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure plan requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. These laws and regulations also prohibit certain activity in wetlands unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. In addition, on October 20, 2011, the EPA announced a schedule to develop pre-treatment standards for wastewater discharges produced by natural gas extraction from underground coalbed and shale formations. The EPA stated that it will gather data, consult with stakeholders, including ongoing consultation with industry, and solicit public comment on a proposed rule for coalbed methane in 2013 and a proposed rule for shale gas in 2014. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions.

The OPA is the primary federal law for oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must develop and maintain facility response contingency plans and maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. The OPA subjects owners of facilities to strict, joint and several liability for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters.

Noncompliance with the CWA or the OPA may result in substantial administrative, civil and criminal penalties, as well as injunctive obligations. We believe we are in substantial compliance with the requirements of each of these laws.

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.

Facilities and Employees

Our principal executive offices are located at 1001 Louisiana Street, Houston, Texas 77002. Our telephone number is (713) 997-1000. As of August 15, 2013, we had 806 full-time employees in the United States. In addition, we had 32 employees in Brazil who are subject to collective bargaining arrangements. We also hire independent contractors.

Legal Proceedings

From time to time, we are a party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment related disputes. We do not believe the results of these proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity. For additional information, see Note 8 to our historical consolidated financial statements and related notes included elsewhere in this prospectus.

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MANAGEMENT

Board of Directors and Executive Officers

The following table provides information regarding our current executive officers and Board members, including the experience, qualifications, attributes or skills of such board members (with ages as of August 30, 2013). Our current directors were nominated and appointed by the Sponsors pursuant to the terms of the Stockholders Agreement. See "Certain Relationships and Related Party Transactions" for further details regarding the rights of the Sponsors to elect our directors following the consummation of this offering.

Name	Age	Position
Brent J. Smolik	52	President, Chief Executive Officer and Chairman of the Board
Clayton A. Carrell	47	Executive Vice President and Chief Operating Officer
Joan M. Gallagher	49	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	41	Director
Joshua J. Harris	48	Director
Sam Oh	43	Director
Ilrae Park	46	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 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, Historical EP Energy Corporation, 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, Historical EP Energy Corporation, 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.

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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, Historical EP Energy Corporation. In that capacity, Ms. Gallagher had HR responsibility for El Paso Corporation's exploration and production business unit and from January 2010 to February 2011 she also had HR responsibilities for shared services and midstream. Prior to 2005, Ms. Gallagher served as Vice President and Chief Administrative Officer of Torch Energy Advisors Incorporated.

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, Historical EP Energy Corporation 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 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, Historical EP Energy Corporation, 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 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 B.S. and M.S. in nuclear engineering from Brooklyn Polytech (now NYU Polytechnic) and holds an M.S. 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 from May 2012 to August 2013. Mr. Beard joined Apollo in 2010 as the Global Head of Natural Resources, based in the New York office. Mr. Beard joined Apollo with 17 years of investment experience, the last ten years 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 gas companies including Apex Energy, Athlon Energy, Belden & Blake Corporation, Canera Resources, Cobalt International Energy, Eagle Energy, Legend Natural Gas I IV, Mariner Energy, NRI Management Group, LLC, Phoenix Exploration, Pinnacle Agriculture, Talos Energy, Titan Operating, and Vantage Energy. Mr. Beard has served on the Board of various oilfield services companies, including CDM Max, CDM Resource Management, and International Logging. Mr. Beard received his BA from the University of Illinois at Urbana. Mr. Beard was appointed to our Board by Apollo. 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.

Joshua J. Harris. Mr. Harris 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 from May 2012 to August 2013. Mr. Harris is a Senior Managing Director of Apollo Global Management, LLC and Managing Partner of Apollo Management, L.P., which he co-founded in 1990. Prior to 1990, Mr. Harris was a member of the Mergers and Acquisitions Group of Drexel Burnham Lambert Incorporated. Mr. Harris currently serves on the boards of directors of Apollo Global Management, LLC, Berry Plastics Group Inc., CEVA Group plc, Momentive Performance Materials and the holding company for

Constellium and is the Managing Partner of the Philadelphia 76ers. During the past five years, Mr. Harris has served on the boards of directors of Verso Paper, Metals USA, Nalco, Covalence Specialty Materials, United Agri Products, Quality Distribution, Whitmire Distribution, Noranda Aluminum, and LyondellBasell Industries and served as a general partner of AP Alternative Assets, L.P. Mr. Harris is actively involved in charitable and political organizations. Mr. Harris graduated summa cum laude and Beta Gamma Sigma from the University of Pennsylvania's Wharton School of Business with a Bachelor of Science degree in Economics and received his Master of Business Administration from the Harvard Business School, where he graduated as a Baker and Loeb Scholar. Mr. Harris was appointed to our Board by Apollo. Based upon Mr. Harris' leadership of Apollo and his extensive financial and business experience, we believe that he possesses the requisite 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 from May 2012 to August 2013. Mr. Oh joined Apollo in 2008. He is a Senior Partner and one of the original founding members of Apollo's Natural Resources Group and is a member of the firm's Operating Committee. Prior to 2008, 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 18 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 made by Apollo managed funds, 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. Mr. Oh received a Bachelor of Science from the University of Pennsylvania's Wharton School of Business and a Master of Business Administration 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 Apollo. 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 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 M.B.A. 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 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 A.B. 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 from May 2012 to August 2013. Mr. Wilson joined Apollo in 2009, where he is currently a senior member of the Natural Resources group. 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 and Talos Energy and previously served as a director of Parallel Petroleum. Mr. Wilson graduated from the University of Texas at Austin and received his Master of Business Administration from INSEAD, Fontainebleau, France. He has also taught business courses at universities in China. Mr. Wilson was appointed to our Board by Apollo. 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. Upon the completion of this offering, we expect that our Board will have 11 directors, (i) five of whom will be designated by Apollo, (ii) two of whom will be designated by Riverstone, (iii) one of whom will be designated by Access, (iv) one of whom will be designated by KNOC, (v) one of whom will be our chief executive officer and (vi) one of whom will be an independent director designated by Apollo. Apollo has the right to designate any director as the Chairman of the Board. Apollo has 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

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directors following the Effective Time, 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 NYSE. See "Certain Relationships and Related Party Transactions" for further details.

We intend to avail ourselves of the "controlled company" exception 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 nominating committees composed entirely of independent directors. We will be required, however, to have an audit committee with one independent director during the 90-day period beginning on the Effective Time. After such 90-day period and until one year from 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.

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.

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 Party Transactions" for further details.

Audit Committee. Upon the Effective Time, we expect that our Audit Committee will consist of members: . Our Board has determined that qualifies as an "audit committee financial expert" as such term is defined in Item 407(d)(5) of Regulation S-K and that is independent as independence is defined in Rule 10A-3 of the Exchange Act and under the NYSE listing standards. We intend to avail ourselves of the "controlled company" exception under the NYSE listing rules, which means we will be required to have an audit committee with one independent director during the 90-day period beginning on the Effective Time. 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.

Compensation Committee. Upon the Effective Time, we expect that our Compensation Committee will consist of members: . The Compensation Committee is responsible for formulating, evaluating and approving the compensation and employment arrangements of our senior officers. We intend to avail ourselves of the "controlled company" exception under the NYSE listing rules which eliminates the requirement that we have a compensation committee composed entirely of independent directors.

Nominating Committee. Upon the Effective Time, we expect that our Nominating Committee will consist of members: . The 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 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 Party Transactions Stockholders

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Agreement Composition of the Board" for further details. We intend to avail ourselves of the "controlled company" exception under the NYSE listing rules which eliminates the requirement that we have a nominating and governance 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 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.

Compensation Discussion and Analysis

The following compensation discussion and analysis ("CD&A"), provides information relevant to understanding the 2012 compensation of the executive officers identified in the Summary Compensation Table below, to whom we refer as our named executive officers. They include our Chief Executive Officer, Mr. Brent J. Smolik, our Chief Financial Officer, Mr. Dane E. Whitehead, and our other three most highly compensated executive officers, Mr. Clayton A. Carrell, Mr. John D. Jensen, and Ms. Marguerite N. Woung-Chapman. The focus of this CD&A relates to our executive compensation policies and decisions following the closing of the Acquisition in May 2012. Unless otherwise stated, this compensation discussion does not give effect to the Corporate Reorganization or this offering (including the stock split). 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. 2012 Compensation Decisions

V. Other Compensation Matters

I. Compensation Objectives

In connection with the closing of the Acquisition in May 2012, we adopted new compensation programs designed to achieve the following objectives:

- attract, retain and motivate the high-performing executive talent necessary at a new privately held operating company, 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 of our Board (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.

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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.

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 2012 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 anticipated inflation
Performance-Based Annual Cash Incentive Awards	To motivate named executive officers and reward them for their 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

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Compensation Element	Objective	Key Features
*Long-Term Equity Awards** * 2012 long-term equity awards were granted in the form of equity interests in EPE Acquisition. In connection with the Corporate Reorganization, the MIPs were converted into Class B common stock and the Class A units were converted into common stock as described in "Corporate Reorganization."	To align interests of executive officers with our equity owners and encourage retention	Grant of equity awards following closing of the Acquisition consisting of following: *Management Incentive Units (MIPs)*: intended to constitute profits interests issued at no cost and have value only to the extent that the value of company increases vest ratably over 5 years or earlier in connection with certain liquidity events become payable only upon occurrence of certain liquidity events *Class A Unit "Matching" Grant*: each named executive officer purchased with his own funds Class A units in our parent company following closing of the Acquisition named executive officers awarded a "matching" Class A unit grant equal to 50% of the Class A units purchased

	Class A units are vested, but subject to transfer restrictions until earliest of four years from grant and certain liquidity events and subject to repurchase at the company's election in certain termination scenarios

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Compensation Element	**Objective**	**Key Features**
401(k) Plan	To provide retirement savings in a tax-efficient manner	Retirement benefits are provided under the following 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 a "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 $2^1/_2$ times the executive officer's annual salary

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Compensation Element	Objective	Key Features
Severance	To provide a measure of financial security in the event that an executive's employment is terminated without cause	Severance payable in the event of an executive's involuntary termination of employment without cause or voluntary 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 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 denominated in shares of common stock). In addition, following this offering, we will continue to evaluate our compensation programs in light of our status as a public company.

IV. 2012 Compensation Decisions

2012 Annual Base Salaries and 2012 Target Bonus Opportunities

Our named executive officers entered into employment agreements with EPE Acquisition in connection with the closing of the Acquisition in May 2012. 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. The following table sets forth the base salaries and annual target bonus opportunities for our named executive officers for 2012.

Annual Base Salaries and Target Bonus Opportunities

Name	2012 Base Salary ($)(1)	2012 Target Bonus Opportunity (% of salary)(2)
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) Base salary amounts became effective as of the closing of the Acquisition on May 24, 2012. Prior to such time, our named executive officers received base salary amounts from El Paso Corporation in accordance with the position each held at El Paso Corporation prior to the Acquisition.

(2) Actual bonus amounts may range from 0% - 200% of target.

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Annual Cash Incentive Awards for 2012 Performance

2012 Scorecard. Shortly following the closing of the Acquisition in May 2012, the Compensation Committee approved our 2012 scorecard for use in determining 2012 cash incentive awards. The 2012 scorecard consists of four 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 between five to nine individual 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 2012 scorecard categories and weightings are set forth in the following table.

Scorecard Category	Weighting
Current Period Returns	45%
Long-Term Value Creation	35%
Health, Safety and Ethics	10%
Transition Milestones	10%

Annual Incentive Bonus Pool Funding. The annual incentive bonus pool was designed to fund based on the achievement levels of the 2012 scorecard, with target performance resulting in 100% pool funding. The bonus pool's funding uses a sliding scale approach based on actual scorecard achievement levels and was designed with significant upside to motivate employees to achieve, and reward them for achieving superior performance. The following table sets forth the percentage that the annual incentive bonus pool is funded based on the level of performance relative to the performance goals that were established for the year.

Funding of the Annual Incentive Bonus Pool

Performance	Pool Funding
Maximum Goals Exceeded	200%(1)
Maximum Goals Met	150%(2)
Target Goals Met	100%(3)
Threshold Goals Met	50%(4)
Threshold Not Met	0%

(1) The maximum funding of the annual incentive bonus pool is 200% for performance that exceeds the maximum performance level.

(2) For performance above maximum, actual funding is between 150% and 200%, as determined by the Compensation Committee.

(3) For performance above target but below maximum, actual funding is between 100% and 150%, as determined by the Compensation Committee

(4) For performance above threshold but below target, actual funding is between 50% and 100%, as determined by the Compensation Committee.

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 in determining their 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 overall pool funding and individual performance adjustments.

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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 bonus pool funding 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 2012

	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 2012 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 2013, the Compensation Committee reviewed the actual performance of our company relative to the 2012 scorecard and, based on the achievement levels and designated weightings of each of the four scorecard categories, approved a 2012 company scorecard achievement level of 119%, reflecting above-target scorecard performance.

The Compensation Committee also evaluated each executive officer's individual performance and contributions during 2012 and discussed with our CEO his recommendation as to the appropriate bonus levels for the executive officers reporting to him.

2012 Annual Incentives. Based on the policies described above, the Compensation Committee approved the following annual incentive bonuses for our named executive officers, reflecting both 2012 scorecard achievement as well as individual performance, which were paid in March 2013.

Annual Cash Incentives for 2012 Performance

	Cash Incentive Bonus ($)
Brent J. Smolik	1,147,500
Dane E. Whitehead	630,000
Clayton A. Carrell	540,000
John D. Jensen	510,000
Marguerite N. Woung-Chapman	280,000

2012 Long-Term Incentive Award Grants

EPE Acquisition provided our named executive officers with two forms of long-term equity incentive awards, each of which is designed to align the interests of our named executive officers with that of our equity investors, as described below. These awards were granted at or shortly following the closing of the Acquisition.

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Management Incentive Units. At the time of the closing of the Acquisition, EPE Acquisition issued Management Incentive Units ("MIPs") to our executive officers, which units were intended to constitute profits interests. The number of MIPs awarded to each named executive officer is set forth in the table below.

Management Incentive Units

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

(1) The MIPs were issued on May 24, 2012. In connection with the Corporate Reorganization, each MIP was converted into one share of Class B common stock, resulting in the following holdings of Class B common stock by the named executive officers: Mr. Smolik: 207,985 Class B shares; Mr. Whitehead: 69,328 Class B shares; Mr. Carrell: 69,328 Class B shares; Mr. Jensen: 69,328 Class B shares; and Ms. Woung-Chapman: 27,731 Class B shares.

Prior to the Corporate Reorganization, each award of MIPs represented a share in future appreciation of EPE Acquisition, 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. In addition, the MIPs would have vested on an accelerated basis and become payable based on the achievement of certain predetermined performance measures, including the occurrence of certain liquidity events where our Sponsors received a return of at least one times their invested capital in our company. The MIPs were issued at no cost to the executives and would have had value only to the extent that the value of EPE Acquisition increased and a liquidity event occurred. If the named executive officer voluntarily terminated his or her employment without good reason, 25% of the vested award and all unvested awards would be forfeited. See the " Potential Payments upon Termination or Change in Control" section for further detail. In connection with the Corporate Reorganization, all outstanding MIPs were converted into shares of Class B common stock as described in the table above and such shares remain subject to all of the vesting provisions 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 Apollo 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. 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 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 an exchange will depend on the return on invested capital in the Company and EPE Acquisition received by Apollo and Riverstone subject to an adjustment multiple. See "Description of Capital Stock Class B common stock," "Description of Capital Stock Distributions Upon a Liquidation" and "Description of Capital Stock Class B Exchange."

Class A Investment Units. In addition to the MIPs described above, each of our named executive officers purchased with his or her own funds Class A units (capital interests) in EPE Acquisition shortly

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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 Sponsors. 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 "Management Executive Compensation 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 as described in "Corporate Reorganization." The number of Class A units issued to each named executive officer is set forth in the table below.

Class A Units

Name	Buy-In Units (#)(1)	Matching Units (#)(2)	Total Units (#)
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 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, resulting in the following holdings of common stock by the named executive officers in respect of their buy-in units: Mr. Smolik: 4,000 shares; Mr. Whitehead: 1,700 shares; Mr. Carrell: 1,200 shares; Mr. Jensen: 1,200 shares; and Ms. Woung-Chapman: 740 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, resulting in the following holdings of common stock by the named executive officers in respect of their matching units: Mr. Smolik: 2,000 shares; Mr. Whitehead: 850 shares; Mr. Carrell: 600 shares; Mr. Jensen: 600 shares; and Ms. Woung-Chapman: 370 shares.

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

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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 below.

2013 Guaranteed Bonus

In connection with the purchase by our named executive officers of Class A units of EPE Acquisition 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 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 CD&A. 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 will be reflected in next year's Summary Compensation Table under the "bonus" column as part of 2013 compensation in accordance with SEC reporting requirements.

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Executive Compensation

The following table and the narrative text that follows it provide a summary of the compensation earned or paid to our named executive officers on or following the closing of the Acquisition on May 24, 2012 according to applicable SEC regulations. The principal position listed for each named executive officer below reflects the current position each executive holds at EP Energy Corporation. The compensation reflected for each individual was for his or her services provided in all capacities to us and our subsidiaries.

Summary Compensation Table

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

(1) The amount in this column reflects base salary amounts earned by our named executive officers on or after the closing of the Acquisition on May 24, 2012, and as such, represents approximately seven months of base salary. The annualized base salary levels for each our named executive officers following the closing of the Acquisition are as follows: $850,000 for Mr. Smolik; $450,000 for Mr. Whitehead; $400,000 for Mr. Carrell; $400,000 for Mr. Jensen; and $370,000 for Ms. Woung-Chapman. Please see "Management Compensation Discussion and Analysis" for further detail.

(2) The amount in this column 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 9 to our consolidated financial statements included elsewhere in this prospectus. 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 "Management Compensation Discussion and Analysis" for further detail on these grants.

(3) The amount in this column reflects each named executive officer's annual cash incentive bonus earned for 2012 performance, which amounts were paid to the named executive officers in March, 2013.

(4) The compensation reflected in the "All Other Compensation" column for 2012 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 below.

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All Other Compensation included in the Summary Compensation Table for 2012

Name	Company Contributions to the 401(k) Retirement Plan ($)	Annual Executive Physicals ($)(A)	Financial Planning ($)(B)	Total ($)
Brent J. Smolik	6,750	1,300		8,050
Dane E. Whitehead	7,292	1,300		8,592
Clayton A. Carrell	16,042		5,137	21,179
John D. Jensen	9,634	1,300	6,288	17,222
Marguerite N. Woung-Chapman	15,549	1,358		16,907

(A) The amounts in this column for 2012 reflect our cost for executive officer annual physicals.

(B) The amounts in this column for 2012 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. Messrs. Smolik and Whitehead also received financial planning services during 2012; however, those services were paid for by El Paso Corporation pursuant to agreements in place prior to the sale of EP Energy and are therefore not reflected in this column. Ms. Woung-Chapman elected not to receive financial planning services during 2012.

2012 Realized Pay Table

The table below supplements the Summary Compensation Table that appears above. This table shows the compensation actually realized by our named executive officers in 2012 for service on or after the closing of the Acquisition on May 24, 2012. This table is supplementary in nature and is not intended to replace the detailed disclosures set forth in the Summary Compensation Table above. The primary difference between this supplemental table and the standard Summary Compensation Table is the removal of the "stock awards" column from this table. SEC rules require that the grant date fair value of all stock awards be reported in the Summary Compensation Table for the year in which they were granted. As noted in the Summary Compensation Table and discussed in detail in "Management Compensation Discussion and Analysis," in 2012 our named executive officers were awarded MIPs and were also awarded a "matching" Class A unit grant in connection with their purchase of Class A units in EPE Acquisition. As a result, a significant portion of the total compensation amounts reported in the Summary Compensation Table relate to stock awards that were not vested and/or are subject to significant transfer restrictions, that were not publicly traded, and for which the value is uncertain (and with respect to the MIPs, that may end up having no value at all). In

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contrast, the supplemental table below includes only amounts actually realized by our named executive officers for service in 2012 following the closing of the Acquisition.

Name and Principal Position	Year	Salary ($)(1)	Annual Incentive Bonus ($)(2)	All Other Compensation ($)(3)	Total ($)
Brent J. Smolik President & Chief Executive Officer	2012	511,063	1,147,500	8,050	1,666,613
Dane E. Whitehead Executive Vice President & Chief Financial Officer	2012	270,395	630,000	8,592	908,987
Clayton A. Carrell Executive Vice President & Chief Operating Officer	2012	240,372	540,000	21,179	801,551
John D. Jensen Executive Vice President, Operations Services	2012	240,372	510,000	17,222	767,594
Marguerite N. Woung-Chapman Senior Vice President, General Counsel & Corporate Secretary	2012	222,382	280,000	16,907	519,289

(1) Amounts shown equal the amounts reported in the "Salary" column of the Summary Compensation Table.

(2) Amounts shown equal the amounts reported in the "Non-Equity Incentive Plan Compensation" column of the Summary Compensation Table.

(3) Amounts shown equal the amounts reported in the "All Other Compensation" column of the Summary Compensation Table.

Grants of Plan-Based Awards

The following table sets forth the range of potential annual cash incentive bonuses for 2012 performance as a dollar amount for each of the named executive officers. The table also sets forth the number of MIPs and the number of matching Class A units of EPE Acquisition awarded during 2012 to the named executive officers. In satisfaction of the applicable SEC regulations, the table further sets forth the date of grant of each award.

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Grants of Plan-Based Awards
During the Year Ended December 31, 2012

Name	Grant Date(2)	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(1) Threshold ($)	Target ($)	Maximum ($)	All Other Stock Awards: Number of Shares of Stock or Units (#)(3)	Grant Date Fair Value of Stock and Option Awards ($)(4)
Brent J. Smolik						
Short-Term Incentive	N/A	425,000	850,000	1,700,000		
MIPs	5/24/2012				207,985	18,951,593
Class A Units (matching grant)	5/24/2012				2,000	2,000,000
Dane E. Whitehead						
Short-Term Incentive	N/A	225,000	450,000	900,000		
MIPs	5/24/2012				69,328	6,317,167
Class A Units (matching grant)	5/24/2012				850	850,000
Clayton A. Carrell						
Short-Term Incentive	N/A	200,000	400,000	800,000		
MIPs	5/24/2012				69,328	6,317,167
Class A Units (matching grant)	5/24/2012				600	600,000
John D. Jensen						
Short-Term Incentive	N/A	200,000	400,000	800,000		
MIPs	5/24/2012				69,328	6,317,167
Class A Units (matching grant)	5/24/2012				600	600,000
Marguerite N. Woung-Chapman						
Short-Term Incentive	N/A	101,750	203,500	407,000		
MIPs	5/24/2012				27,731	2,526,849
Class A Units (matching grant)	5/24/2012				370	370,000

(1) These columns show the potential value of the payout of the annual cash incentive bonuses for 2012 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 paid for 2012 performance is shown in the Summary Compensation Table under the "Non-Equity Incentive Plan Compensation" column.

(2) In accordance with FASB ASC Topic 718, the grant date of the MIPs and matching Class A unit awards was determined to be May 24, 2012. However, the actual transfer of Class A units (both buy-in and matching) to the named executive officers did not occur until July 23, 2012 following the receipt by EPE Acquisition of the buy-in proceeds from the named executive officers relating to their purchase of the Class A units.

(3) This column shows the number of MIPs (profits interests) and the number of matching Class A units of EPE Acquisition granted in 2012 to our named executive officers. The MIPs were scheduled to vest in five equal annual installments beginning one year from the date of grant. The Class A units were fully vested upon grant, but subject to transfer restrictions for a period of four years from the date of grant. In connection with the Corporate Reorganization, each MIP was converted into one share of Class B common stock, and each Class A unit was converted into one share of common stock, resulting in the following holdings by the named executive officers in respect of the awards disclosed in this column: Mr. Smolik: 207,985 shares of Class B common stock and 2,000 shares of common stock; Mr. Whitehead: 69,328 shares of Class B common stock and 850 shares of common stock; Mr. Carrell: 69,328 shares of Class B common stock and 600 shares of common stock; Mr. Jensen: 69,328 shares of Class B common stock and 600 shares of common stock; and Ms. Woung-Chapman: 27,731 shares of Class B common stock and 370 shares of common stock.

(4)

This column shows the grant date fair value of the MIPs and Class A matching units computed in accordance with FASB ASC Topic 718 granted to our named executive officers during 2012.

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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 "Management Compensation Discussion and Analysis."

Equity Awards

The equity awards reported in the above table are likewise described in "Management Compensation Discussion and Analysis." They include the MIPs granted to our named executive officers at the time of the closing of the Acquisition, as well as the "matching" Class A units of EPE Acquisition that our named executive officers received in connection with their purchase of Class A units of EPE Acquisition following the closing of the Acquisition.

The MIPs reflected in the table were scheduled to vest ratably over five years based on the executive's continued employment with the company, although 25% of any vested awards would have been forfeitable in the event of certain termination events. In addition, the MIPs would have vested on an accelerated basis and become payable based on the achievement of certain predetermined performance measures, including the occurrence of certain liquidity events where our Sponsors received a return of at least one times their invested capital in our company. The MIPs were issued at no cost and would have had value only to the extent that the value of EPE Acquisition increased and a liquidity event occurred. The grant date fair value per MIP granted on May 24, 2012, was determined to equal $91.12, computed using a reverse option pricing model based on several assumptions. In accordance with FASB ASC Topic 718, 75% of the aggregate grant date fair value of the MIPs will be expensed over the five-year vesting period, with the remaining 25% to be expensed upon a liquidity event when the right to such amounts become nonforfeitable. See Note 9 to our consolidated financial statements included elsewhere in this prospectus for further detail. In connection with the Corporate Reorganization, each MIP was converted into one share of Class B common stock, and each matching Class A unit was converted into one share of common stock. The shares of Class B common stock issued in exchange for the MIPs remain subject to the same vesting conditions applicable to the corresponding MIPs, as described above.

The matching Class A units reflected in the table were vested upon grant but, along with the buy-in units purchased by the executives, are subject to transfer restrictions until the earliest of four years from grant and certain liquidity events. The grant date fair value of each Class A unit was determined to equal $1,000. The shares of common stock issued in exchange for the Class A units remain subject to the same transfer restrictions.

Class A Unit Distributions

In December 2012, the Board of Managers of EPE Acquisition authorized a cash distribution to all Class A unitholders of our parent on a pro-rata basis. 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. In addition, in July 2013 the Board of Managers of EPE Acquisition authorized an additional pro-rata cash distribution to all Class A unitholders of our parent, which distribution was made prior to the Corporate Reorganization.

Employment Agreements

As discussed in the "Management 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.

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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 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 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 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 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

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certain termination events, as well as certain non-compete, non-solicitation and confidentiality restrictions.

Marguerite N. Woung-Chapman

EPE Acquisition 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 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, 2012.

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 ($)(2)
Brent J. Smolik	207,985	18,951,593
Dane E. Whitehead	69,328	6,317,167
Clayton A. Carrell	69,328	6,317,167
John D. Jensen	69,328	6,317,167
Marguerite N. Woung-Chapman	27,731	2,526,849

(1) Number of unvested MIPs as of December 31, 2012. In connection with the Corporate Reorganization, each MIP was converted into one share of Class B common stock, resulting in the following holdings by the named executive officers: Mr. Smolik: 207,985 shares; Mr. Whitehead: 69,328 shares; Mr. Carrell: 69,328 shares; Mr. Jensen: 69,328 shares; and Ms. Woung-Chapman: 27,731 shares. Similar to the corresponding MIPs, the shares of Class B common stock are subject to time-based vesting requirements and are scheduled to vest ratably over 5 years. The first tranche vested on May 24, 2013 and an additional 20% will vest on each of May 24, 2014, 2015, 2016, and 2017.

(2) The values represented in this column have been calculated by multiplying $91.12, the grant date fair value per MIP, by the number of MIPs awarded, as there was no tradable market for the MIPs at fiscal year end. The value that will ultimately be realized, if any, by the named executive officer pursuant to the MIPs is dependent upon future appreciation of the company and the occurrence of certain predetermined liquidity events, and consequently, is not determinable at this time. See Note 9 to our consolidated financial statements included elsewhere in this prospectus for further detail.

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.

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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, 2012 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			15,810	47,430	
Disability Income			300,000		
Survivor Benefit		2,125,000			
Dane E. Whitehead					
Severance Payment				2,250,000	
Continued Medical			15,810	31,620	
Disability Income			270,000		
Survivor Benefit		1,125,000			
Clayton A. Carrell					
Severance Payment				2,000,000	
Continued Medical			15,810	31,620	
Disability Income			240,000		
Survivor Benefit		1,000,000			
John D. Jensen					
Severance Payment				2,000,000	
Continued Medical			15,810	31,620	
Disability Income			240,000		
Survivor Benefit		1,000,000			
Marguerite N. Woung-Chapman					
Severance Payment				1,350,500	
Continued Medical			7,614	15,228	
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.

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Class A Units and Corresponding Common Stock

As discussed in the Compensation Discussion and Analysis, the Class A units of EPE Acquisition 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 in exchange for such Class A units issued to the named executive officers remain subject to the same vesting and transfer restrictions. In addition, the units were, and following the Corporate 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.

Management Incentive Units (MIPs) and Corresponding 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.

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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, applicable (as determined by the Board), on the repurchase date.

Director Compensation

During 2012 and 2013 to the date of this prospectus, 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. Following the completion of this offering, we expect that our independent non-employee directors will receive cash and/or equity-based compensation for their services as directors. Although the terms of our director compensation program have not yet been determined, we expect such compensation may consist of the following:

- an annual cash retainer of $;
- an additional annual cash retainer of $ for service as the chair of any standing committee; and
- an annual equity-based award granted under our Omnibus Incentive Plan, having a value as of the grant date of $. Equity-based awards are expected to be subject to vesting conditions that have not yet been determined.

Directors will also receive reimbursement for out-of-pocket expenses associated with attending board or committee meetings and director and officer liability insurance coverage. Each director will be fully indemnified by us for actions associated with being a director to the fullest extent permitted under Delaware law. In connection with this offering, we may enter into separate indemnification agreements with each of our directors and executive officers, which may be broader than the specific indemnification provisions contained in Delaware law.

Compensation Committee Interlocks and Insider Participation

The Compensation Committee is currently composed of . During 2012 and 2013 to the date of the prospectus, no member of the Compensation Committee was a former or current officer or employee of the Company. In addition, during 2012 and 2013 to the date of this prospectus, none of our executive officers served (i) as a member of the compensation committee or board of directors of another entity, one of whose executive officers served on our Compensation Committee, or (ii) as a

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member of the compensation committee of another entity, one of whose executive officers served on our Board.

EP Energy Corporation 2013 Omnibus Incentive Plan

We intend to adopt the 2013 Omnibus Incentive Plan of EP Energy Corporation (the "omnibus plan") prior to the completion of this offering, which will be effective no later than the day prior to the completion of this offering. The following is a general description of the omnibus plan. We are in the process of adopting the omnibus plan, and accordingly this summary is subject to change prior to the Effective Time.

Summary of the Omnibus Plan

Purpose of the Omnibus Plan

The purpose of the omnibus plan is to promote the interests of the company and its stockholders by enhancing the company's ability to attract and retain employees and non-employee directors through suitable recognition of their ability and experience. The omnibus plan is further intended to align the employees' and non-employee directors' interests and efforts with the long-term interests of the company's stockholders, and to provide participants with a direct incentive to achieve the company's strategic and financial goals.

Effective Date and Duration

The omnibus plan will become effective when it is approved by our Board of Directors, which will occur prior to the completion of this offering. The plan authorizes the granting of awards for up to ten years from the plan's effective date. The omnibus plan will remain in effect, subject to the right of our Board of Directors to terminate the plan at any time, until no awards remain outstanding.

Administration of the Omnibus Plan

The Compensation Committee of our Board of Directors is the plan administrator. The plan administrator has the full power to select employees and non-employee directors to receive awards under the omnibus plan; determine the terms and conditions of awards; construe and interpret the plan and any awards granted thereunder; and, subject to certain limitations, amend the terms and conditions of outstanding awards. The plan administrator's determinations and interpretations under the omnibus plan are binding on all interested parties.

Eligibility and Participation

Eligible participants include all employees (other than an employee who is a member of a unit covered by a collective bargaining agreement) of the company or any subsidiary, including employees who are members of our Board of Directors, as well as non-employee members of our Board of Directors and consultants, as determined by the plan administrator.

Shares Subject to the Omnibus Plan

The omnibus plan currently authorizes the issuance of up to shares of our common stock.

Any shares that are potentially deliverable under an award granted under the omnibus plan that is canceled, forfeited, settled in cash, expires or is otherwise terminated without delivery of such shares shall not be counted as having been issued under the plan. Likewise, shares that have been issued in connection with an award of restricted stock that is canceled or forfeited prior to vesting or settled in cash, causing the shares to be returned to the company, will not be counted as having been issued under the plan.

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If shares are returned to the company in satisfaction of taxes related to restricted stock, in connection with a cash-out of restricted stock (but excluding upon forfeiture of restricted stock) or in connection with the tendering of shares by a participant in satisfaction of the exercise price or taxes relating to an award, such issued shares shall not become available again for issuance under the plan. In addition, each stock appreciation right issued under the plan will be counted as one share issued under the plan without regard to the number of shares issued to the participant upon exercise of such stock appreciation right.

In the event of a change in capitalization, as defined in the omnibus plan, the plan administrator shall make such adjustments as it determines are appropriate and equitable to (i) the maximum number and class of shares of common stock or other stock or securities with respect to which awards may be granted under the plan, (ii) the maximum number and class of shares of common stock or other stock or securities that may be issued upon exercise of stock options, (iii) the individual annual grant limits for Section 162(m), (iv) the number and class of shares of common stock or other stock or securities that are subject to outstanding awards and the option price or grant price therefor, if applicable, and (v) performance goals.

The shares to be delivered under the omnibus plan may be made available from any combination of shares held in EP Energy's treasury or authorized but unissued shares of EP Energy's common stock.

Individual Annual Grant Limits

For purposes of Section 162(m), (i) the maximum number of our shares with respect to which stock options or stock appreciation rights may be granted to any participant in any calendar year is million shares; (ii) the maximum number of our shares of restricted stock that may be granted to any participant in any calendar year is million shares; (iii) the maximum number of our shares with respect to which restricted stock units, performance shares, performance units or other stock-based awards may be granted to any participant in any calendar year is million shares; and (iv) the maximum amount of other awards under the plan, including cash incentive awards, that may be paid pursuant to the omnibus plan in any calendar year to any participant is $ million.

Awards under the Omnibus Plan

Grants under the omnibus plan may be made in the form of stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, incentive awards, and other cash or stock-based awards.

Types of Awards

Following is a general description of the types of awards that may be granted under the omnibus plan. Terms and conditions of awards will be determined on a grant-by-grant basis by the plan administrator, subject to limitations contained in the omnibus plan.

Stock Options. A stock option is the grant of an option made to eligible employees to purchase a specific number of shares of common stock under certain terms and conditions and for a set price. The plan administrator will determine the price of the shares of common stock covered by each stock option, except that the stock option price may not be less than 100% of the fair market value of the shares of common stock on the date the stock options are granted. The plan administrator will also set the term of each stock option. The term of a stock option may not exceed ten years from the date of the grant.

Stock options granted under the omnibus plan may be either "incentive stock options" that qualify under the meaning of Section 422 of the Code or "non-qualified stock options" that are not designed to qualify under Section 422. With respect to each stock option granted under the omnibus plan, the plan administrator will determine the nature and extent of any restrictions to be imposed on the shares of common stock that may be purchased, including, but not limited to, restrictions on the transferability of shares acquired upon exercise. Stock options granted under the omnibus plan cannot be repriced without the approval of the stockholders other than in connection with a "change in capitalization" in which an adjustment is permitted. In addition, underwater stock options cannot be cashed out without stockholder approval.

The actual purchase of shares of common stock pursuant to a stock option is called the "exercise" of that stock option. Stock options granted under the omnibus plan will be exercisable at such time or times and subject to such terms and conditions as determined by the plan administrator at the time of grant. The plan administrator may waive such restrictions on the exercisability of a stock option at any time on or after the date of the grant in whole or in part, as the plan administrator may determine in its sole discretion. Shares covered by a stock option may be purchased at one time or in such installments over the option period as determined by the plan administrator.

The plan administrator will determine the form of payment of the stock option price, which may include cash, shares of common stock already owned by the participant, or any combination of cash and shares of common stock, with the fair market value of the common stock valued as of the day prior to delivery. The plan administrator may also designate additional forms of payment that will be permitted, provided the methods are permitted by applicable laws and regulations. A participant will not have any of the rights of a stockholder until the shares of common stock are issued to the participant.

Stock Appreciation Rights. A stock appreciation right granted under the omnibus plan is a right to receive the appreciation in value of a share of common stock between the date the stock appreciation right or related award is granted and the date it is exercised. A stock appreciation right may be granted freestanding or in tandem or in combination with any other award under the omnibus incentive plan. Upon exercise, each stock appreciation right will entitle a participant to receive payment from the company determined by multiplying (i) the difference between the fair market value of a share of common stock on the date the stock appreciation right is exercised over the price fixed at the date of grant (which shall not be less than 100% of the fair market value of a share of common stock on the date of grant) times (ii) the number of shares of common stock with respect to which the stock appreciation right is exercised. At the discretion of the plan administrator, the payment upon stock appreciation right exercise may be in cash, in shares of common stock of equivalent value, or in some combination thereof.

A stock appreciation right granted in tandem with any other award under the omnibus plan shall be exercisable only at such times and to the extent that the award as to which it relates is exercisable or at such other times as the plan administrator may determine. A stock appreciation right expires at the same time the associated award expires, but in no case shall the right be exercisable later than the tenth anniversary of the date of its grant. A holder of a stock appreciation right will not have any of the rights of a stockholder until shares of common stock are issued. Stock appreciation rights granted under the omnibus plan cannot be repriced without the approval of the stockholders other than in connection with a "change in capitalization" in which an adjustment is permitted. In addition, underwater stock appreciation rights cannot be cashed out without stockholder approval.

Performance Shares and Performance Units. Performance shares granted under the omnibus plan represent the right to receive a number of shares of common stock for each performance share granted. Performance units granted under the omnibus plan represent the right to receive a payment, either in cash or shares of common stock, equal to the value of a performance unit. Performance shares or performance units may be granted to participants at any time and from time to time as the plan administrator determines. Performance shares and performance units may be granted alone or in combination with any other award.

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Prior to the grant of each performance share or performance unit, the plan administrator will establish the initial number of shares of common stock for each performance share and the initial value for each performance unit. In addition, the plan administrator will determine the performance goals used to determine the extent to which the participant receives a payout for the performance period. The plan administrator may assign percentages or other relative values of performance that will be applied to determine the extent to which the participant receives a payout. After a performance period has ended, the plan administrator will determine the extent to which the performance goals have been met and the holder of a performance share or performance unit is entitled to receive a payout of the number of performance shares or value of performance units awarded. No payout will be made without written certification by the plan administrator that the applicable performance goals have been satisfied. No dividends will be paid on unvested performance shares or unvested performance units.

Restricted Stock. Restricted stock is common stock that is subject to forfeiture if a participant's employment terminates before a specified date, if pre-established performance goals for a specified time period are not attained or due to such other factors or criteria as the plan administrator may determine. Restricted stock may be granted to participants under the omnibus plan at any time and from time to time as the plan administrator determines. Generally, there is no purchase price associated with restricted stock.

A participant who receives a grant of restricted stock will be recorded as a stockholder of EP Energy and, except as otherwise determined by the plan administrator, will have all the rights of a stockholder with respect to such shares (except with respect to the restrictions on transferability during the restriction period), including the right to vote the shares and receive dividends and other distributions paid with respect to the underlying shares. When all applicable conditions associated with a participant's restricted stock have been met, the participant will be issued unrestricted shares of common stock subject to any required share withholding to satisfy tax withholding obligations.

Restricted Stock Units. A restricted stock unit granted under the omnibus plan represents a right to receive a payment, in cash or shares of common stock, equal to the value of a share of common stock. Restricted stock units may be granted to participants at any time and from time to time as the plan administrator determines.

A participant who receives a grant of restricted stock units will not be recorded as a stockholder of EP Energy and will not have any of the rights of a stockholder unless or until the participant is issued shares of common stock in settlement of the restricted stock units granted. The plan administrator may determine that restricted stock units are entitled to dividend equivalents equal to cash dividends, if any, paid on shares of common stock. Dividend equivalents may be paid in cash or common stock or credited to the participant as additional restricted stock units. When all applicable conditions associated with a participant's restricted stock units have been met, restricted stock units will be settled in any combination of cash or shares of common stock subject to the payment of all taxes required to be withheld.

Incentive Awards. An incentive award is a percentage of a participant's base salary, fixed dollar amount or other measure of compensation to be awarded in cash or other awards under the omnibus plan at the end of a performance period if certain performance goals or other performance measures are achieved. Prior to the beginning of a particular performance period, or not later than 90 days following the beginning of the relevant fiscal year, the plan administrator will establish the performance goals or other performance measures that must be achieved for any participant to receive an incentive award for that performance period. The performance goals or other performance measures may be based on any combination of corporate and business unit performance goals or other performance measures. The plan administrator may also establish one or more company-wide performance goals or other performance measures that must be achieved. Incentive awards become payable to the extent that

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the plan administrator certifies in writing that the performance goals or other performance measures selected for a particular performance period have been attained.

At the end of each performance period and within 30 days after the information necessary to make a determination is available for the performance period, the plan administrator will determine whether the performance goals or other performance measures for the performance period have been achieved and the amount of each participant's award. Incentive awards may be paid in any combination of cash and/or other awards.

Cash and Other Stock-Based Awards. The plan administrator may grant cash awards to participants in such amounts and upon such terms, including the achievement of specific performance criteria as the plan administrator may determine. The plan administrator may also grant other types of equity-based or equity-related awards known as "other stock-based awards," which would include deferred share awards payable at a specified time or date, under the omnibus plan. Other stock-based awards may involve the transfer of actual shares of common stock or payment in cash or otherwise of amounts based on the value of shares of common stock. The plan administrator may establish performance criteria applicable to such awards in its sole discretion. Each cash award granted will specify a payment amount or payment range as determined by the plan administrator. Each other stock-based award will be expressed in terms of shares of common stock or units based on shares of common stock, as determined by the plan administrator.

Performance Goals

The plan administrator may determine that performance criteria will apply to awards granted under the omnibus plan. To the extent that awards are intended to qualify as "performance-based compensation" under Section 162(m) of the Code, the performance goals may include any one or more of the following, either individually, alternatively or in any combination, applied to either EP Energy as a whole or any subsidiary, either individually, alternatively or in any combination, and measured either annually or cumulatively over a period of years, on an absolute basis or relative to the predetermined target, to previous years' results or to a designated comparison group, in each case as specified by the plan administrator:

- earnings;
- earnings before interest and taxes;
- earnings before interest, taxes, depreciation and amortization;
- earnings per share;
- net income;
- operating income;
- revenues;
- operating cash flow;
- free cash flow;
- debt level;

debt ratios or other measures of credit quality or liquidity;

equity ratios;

expenses;

cost reduction targets;

capital expended;

working capital;

weighted average cost of capital;

operating or profit margins;

interest-sensitivity gap levels;

return on assets;

return on net assets;

return on equity or capital employed;

return on total capital;

amount of the oil and gas reserves;

oil and gas reserve additions;

oil and gas reserve replacement ratios;

costs of finding oil and gas reserves;

oil and gas reserve replacement costs;

daily natural gas and/or oil production;

production and production growth;

absolute or per unit operating and maintenance costs;

absolute or per unit general and administrative costs;

absolute or per unit lease operating expenses;

operating and maintenance cost management;

performance of investment in oil and/or gas properties;

capital efficiency targets (capital/new volumes);

redeployable capital savings targets;

absolute or per unit cash costs;

present value ratio;

drilling inventory growth (% or absolute);

production or reserves per debt adjusted shares;

total shareholder return;

charge-offs;

asset sale targets;

asset quality levels;

value of assets;

fair market value of the common stock;

employee retention/attrition rates;

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- investments;
- regulatory compliance;
- satisfactory internal or external audits;
- improvement of financial ratings;
- safety and environmental targets;
- economic value added;
- achievement of balance sheet or income statement objectives;
- project completion measures; and/or
- other measures such as those relating to acquisitions, dispositions, or customer satisfaction.

The plan administrator will be authorized to adjust the performance goals to include or exclude extraordinary charges, gain or loss on the disposition of business units, losses from discontinued operations, restatements and accounting changes and other unplanned special charges such as restructuring expenses, acquisitions, acquisition expenses, including expenses related to goodwill and other intangible assets, stock offerings, stock repurchases and loan loss provisions.

Termination of Employment

The award agreement applicable to each award granted under the omnibus plan will set forth the effect of a participant's termination of employment or service upon such award. Unless explicitly set forth otherwise in an award agreement or as determined by the plan administrator, (i) all of a participant's unvested and/or unexercisable awards are forfeited automatically upon termination of a participant's employment or service for any reason, and with respect to stock options or stock appreciation rights, a participant is permitted to exercise the vested portion of the stock option or stock appreciation right for three months following termination of employment or service, and (ii) all of a participant's awards whether vested or unvested, exercisable or unexercisable are automatically forfeited upon the termination of the participant's employment for cause. Provisions regarding the effect of a termination of employment or service upon an award are determined in the sole discretion of the plan administrator and need not be uniform among all awards or among all participants.

Change in Control

Except as otherwise provided in an award agreement, in the event of a participant's termination of employment (a) without cause or (b) by a participant for "good reason" (as defined in such participant's employment agreement, if applicable), in either event, within two years following a change in control (i) all stock options and stock appreciation rights will become fully vested and exercisable, (ii) the restriction periods applicable to all shares of restricted stock and restricted stock units will immediately lapse, (iii) the performance periods applicable to any performance shares, performance units and incentive awards that have not ended will end and such awards will become vested and payable in cash in an amount assuming target levels of performance by both participants and EP Energy have been achieved and (iv) any restrictions applicable to cash awards and other stock-based awards will immediately lapse and, if applicable, become payable.

Transferability

Awards granted under the omnibus plan may not be transferred, assigned, pledged, or encumbered in any manner except in the case of the death of a participant. Non-qualified stock options may be transferred to certain immediate family members, directly or indirectly or by means of a trust, corporate entity or partnership, as provided for in the omnibus plan and allowed by the plan

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administrator. Any attempt to transfer, assign, pledge, hypothecate or otherwise dispose of awards granted under the omnibus plan, or any right or privilege conferred thereby, contrary to the provisions of the omnibus plan, may result in the forfeiture of any affected award.

Termination and Amendment

The plan administrator, subject to the approval of the board of directors, may from time to time amend the omnibus plan; provided, however, (i) stockholder approval is required to the extent required by applicable law, regulation or stock exchange rule and (ii) no change in any award previously granted under the omnibus plan may be made without the consent of the participant which would impair the right of the participant to acquire or retain common stock or cash that the participant may have acquired as a result of the omnibus plan. The board of directors may at any time suspend the operation of or terminate the omnibus plan with respect to any shares of common stock or rights which are not at that time subject to any award outstanding. No award may be granted under the omnibus plan on or after the tenth anniversary of the effective date of the plan.

Tax Withholding

We may deduct or withhold, or require a participant to remit, an amount sufficient to satisfy federal, state, local, domestic or foreign taxes required by law or regulation to be withheld with respect to any taxable event arising as a result of the omnibus plan.

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PRINCIPAL STOCKHOLDERS

The following table provides certain information regarding the beneficial ownership of our outstanding common stock as of , 2013, and after giving effect to the offering (assuming that the underwriters do not exercise their option to purchase additional shares), for:

- each person or group who beneficially owns more than 5% of our common stock on a fully diluted basis;
- 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 indicated before this offering is based on shares of common stock outstanding on , 2013, and the percentage of ownership after this offering is based on shares of common stock outstanding, including the shares to be issued and sold by the Company and does not take into account any shares of common stock that may be issued in the future in connection with a Class B Exchange.

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.

Upon the closing of this offering, our Sponsors, as a group, will continue to control a majority of our voting common stock. As a result, we will be 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 Before the Offering		Shares of Common Stock Beneficially Owned After the Offering	
	Shares	Percentage	Shares	Percentage
Apollo Funds(1)		53.96%		
Riverstone(2)		14.99%		
Access(3)		14.99%		
KNOC(4)		14.99%		
Brent J. Smolik		*		
Dane E. Whitehead		*		
Clayton A. Carrell		*		
John D. Jensen		*		
Marguerite N. Woung-Chapman		*		
Ralph Alexander				
Gregory A. Beard				
Joshua J. Harris(1)				
Ilrae Park				
Sam Oh				
Robert M. Tichio				
Donald A. Wagner				
Rakesh Wilson				
Directors and executive officers as a group (14 persons)		*		

*
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 principal 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.

(2)
Riverstone V Everest Holdings, L.P. and Riverstone V FT Corp Holdings, L.P. are the record holders of shares of common stock and 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 six person managing committee. Pierre F. Lapeyre, Jr., David M. Leuschen, John Browne, 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

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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 shares of common stock by Texas Oil & Gas Holdings LLC ("TOGH"). Each of RSB Limited, Access Industries Holdings LLC, Access Industries, LLC and Access Industries Management, LLC (the "Access Entities") 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, 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. Each of the Access Entities and Len Blavatnik, and each of their affiliated entities and the officers, partners, members, and managers thereof, other than TOGH, disclaim beneficial ownership of the shares held by TOGH. The address for TOGH, RSB Limited, Access Industries Holdings LLC, Access Industries, LLC, Access Industries Management, LLC 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, Jae-Ik Park, In Chul Kim, Sun Jang Kang, Joo Heon Park, Ho Cheul Shin, Dong Rack Chung, Jae Hyun Kim and Jong Kyu Yoon, 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.

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CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Corporate Reorganization

In connection with our Corporate Reorganization, we engaged in certain transactions with certain affiliates and the members of EPE Acquisition. Please read "Corporate Reorganization" for a description of these transactions.

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."

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. Following the offering, our Board will initially be comprised of not less than 11 directors, (i) five of whom will be designated by Apollo, (ii) two of whom will be designated by Riverstone, (iii) one of whom will be designated by Access, (iv) one of whom will be designated by KNOC, (vi) one of whom will be our chief executive officer and (vii) one of whom will be an independent director designated by Apollo. Pursuant to the Stockholders Agreement, Apollo has the right to designate any director as the Chairman of the Board. Apollo has 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. 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" below. 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. Subject to certain exceptions with respect to the preservation of attorney-client privilege, each observer 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 tables below state the number of board observers that each Sponsor (other than Apollo which has 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

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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

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 Apollo 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 Apollo 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

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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;

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.

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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 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.

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 ("EP Energy Global") and EPE Acquisition (the "Transaction Fee Agreement") relating to the provision of certain structuring, financial, investment banking and other similar advisory services by the Service Providers to EPE Acquisition, its direct and indirect divisions and subsidiaries, parent entities or controlled affiliates (collectively, the "Company Group") in connection with the closing of the Acquisition and future transactions. 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. Subject to the terms and conditions of the Transaction Fee Agreement, in connection with this offering, we will pay to the Service Providers an additional transaction fee equal to the lesser

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of (i) 1% of the aggregate enterprise value paid or provided by the Company Group and (ii) $100,000,000. The Transaction 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 EPE Acquisition, EP Energy Global or any other member of the Company Group. The Transaction Fee Agreement will terminate automatically in accordance with its terms upon termination of the Management Fee Agreement, which, as described below, will terminate upon the closing of this offering.

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 and EP Energy Global (the "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. In exchange for the provision of such services, we will pay the Management Service Providers a non-refundable annual management fee of $25 million in the aggregate. For 2012, we paid the Management Service Providers a pro-rated management fee of approximately $15.2 million. For 2013, we have paid the Management Service Providers the annual fee of $25 million. The Management Fee Agreement will terminate automatically in accordance with its terms upon the closing of this offering.

Participation of Apollo Global Securities, LLC in Offerings

Apollo Global Securities, LLC ("AGS") is an affiliate of Apollo, one of our equity sponsors, and acted as an initial purchaser in four of our private note offerings in 2012. AGS received approximately $937,500, $2,500,000, $131,250 and $131,439 of the gross spread in the sales of our 6.875% senior secured notes due 2019, our 9.375% senior notes due 2020, our 7.750% senior notes due 2022 and our 8.125%/8.875% senior PIK toggle notes due 2017, respectively. In addition, AGS participated as an arranger and underwriter in connection with our October 2012 issuance of $400 million of incremental term loans and received $100,000 for services rendered in connection with this 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.

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CORPORATE REORGANIZATION

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, 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 caused the initial incorporation of EP Energy Corporation, (ii) certain Legacy Class A Stockholders contributed their Class A membership interests in EPE Acquisition 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, (iii) certain other Legacy Class A Stockholders, which previously held their Class A membership interests in EPE Acquisition 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 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, and (iv) the Legacy Class B Stockholder contributed its Class B membership interests in EPE Acquisition 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, in cancellation of its Class B membership interests in EPE Acquisition. 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. 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 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. For a more detailed description of the Stockholders Agreement and Registration Rights Agreement, see "Certain Relationships and Related Party Transactions Stockholders Agreement" and "Certain Relationships and Related Party Transactions Registration Rights Agreement," respectively.

Following the Corporate Reorganization, we will issue 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 the proceeds paid in respect of such shares of Class B common stock pursuant to the Second Amended and Restated Certificate of

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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.

Structure

The diagram below sets forth our organizational structure after giving effect to the Corporate Reorganization and this offering. This diagram is provided for illustrative purposes only and does not represent all legal entities affiliated with us.

Post- Corporate Reorganization Structure:

(1) The Sponsors, the public stockholders and management will hold %, % and % of shares of common stock, respectively, if the underwriters exercise in full their option to purchase additional shares.

(2) See "Description of Certain Indebtedness."

(3) Co-Issuer of EP Energy LLC's senior secured notes and senior notes.

(4) Guarantors of RBL Facility and senior secured term loans, senior secured notes and senior notes.

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DESCRIPTION OF CAPITAL STOCK

The discussion below describes the material terms of our capital stock, the Second Amended and Restated Certificate of Incorporation and the Amended and Restated Bylaws as they will be in effect upon the completion of this offering and the discussion below and in "Certain Relationships and Related Party Transactions" describes the material terms of the Stockholders Agreement and the Registration Rights Agreement as they will be in effect from the completion of this offering. The following summaries are qualified in their entirety by reference to the Second Amended and Restated Certificate of Incorporation, the Amended and Restated Bylaws, the Stockholders Agreement and the Registration Rights Agreement, copies of which have been filed as exhibits to the registration statement of which the prospectus forms a part.

Upon completion of the offering, our authorized capital stock will consist of shares of common stock, shares of Class B common stock and shares of preferred stock, the rights and preferences of which may be designated by our Board. Upon completion of the offering, there will be shares of common stock issued and outstanding, shares of Class B common stock issued and outstanding and no shares of preferred stock issued and outstanding. As of , 2013, there were holders of record of our common stock and two holders of record of our Class B common stock.

Common Stock

Voting Rights. The holders of our common stock are entitled to one vote per share of common stock on each matter properly submitted to the stockholders on which the holders of shares of common stock are entitled to vote. Subject to the director nomination rights described in "Certain Relationships and Related Party Transactions Stockholders Agreement" and the rights of holders of any series of preferred stock to elect directors under specified circumstances, at any annual or special meeting of the stockholders, holders of common stock will have the exclusive right to vote for the election of directors and on all other matters properly submitted to a vote of the stockholders.

Dividend Rights. All shares of our common stock will be entitled to share equally in any dividends our Board may declare from legally available sources, subject to the terms of any outstanding preferred stock and Class B common stock described below. See " Class B common stock" and " Preferred Stock." Provisions of our debt agreements and other contracts, including requirements under the Second Amended and Restated Certificate of Incorporation and the Stockholders Agreement described elsewhere in this prospectus, may impose restrictions on our ability to declare dividends with respect to our common stock.

Liquidation Rights. Upon a liquidation or dissolution of EP Energy Corporation, whether voluntary or involuntary and subject to the rights of the holders of Class B common stock and any preferred stock, all shares of our common stock will be entitled to share equally in the assets available for distribution to holders of common stock after payment of all of our prior obligations, including any then-outstanding preferred stock, in the manner described in "Distributions Upon a Liquidation."

Registration Rights. Pursuant to the Registration Rights Agreement, we have granted the Legacy Class A Stockholders demand registration rights and/or incidental registration rights, in each case, with respect to certain shares of common stock owned by them. See "Certain Relationships and Related Party Transactions Registration Rights Agreement."

Other Matters. Except as provided by the Stockholders Agreement with respect to the Legacy Class A Stockholders, the holders of our common stock will have no preemptive rights, and our common stock will not be subject to further calls or assessments by us. There are no redemption or sinking fund provisions applicable to our common stock.

Class B Common Stock

Voting Rights. Except as required by law, the holders of our Class B common stock are not entitled to vote.

Dividend Rights. After the consummation of a capital transaction, or following any other distribution or series of distributions of capital proceeds or available cash, where the net return on Invested Capital (as defined below) after taking into account costs and expenses incurred in connection with generating such return and after giving effect to such capital transactions or other distribution or series of distributions of capital proceeds or available cash, in EP Energy Corporation and EPE Acquisition to the Legacy Class A Stockholders ("MOIC") is at least 1.0, all shares of our Class B common stock (whether or not vested) will be entitled to share in dividends our Board may declare from legally available sources, subject to the terms of any outstanding preferred stock and common stock, as if such dividends were proceeds from a liquidation or dissolution of the Company or certain change of control transactions with respect to us and our subsidiaries (taken as a whole) and distributed in the manner described in " Distributions Upon a Liquidation." Provisions of our debt agreements and other contracts, including requirements under the Second Amended and Restated Certificate of Incorporation and the Stockholders Agreement described elsewhere in this prospectus, may impose restrictions on our ability to declare dividends with respect to our Class B common stock. See " Distributions Upon a Liquidation," " Preferred Stock" and " Common Stock."

Liquidation Rights. Upon a liquidation or dissolution of EP Energy Corporation, whether voluntary or involuntary and subject to the rights of the holders of common stock and preferred stock, all shares of our Class B common stock will be entitled to share equally in the assets available for distribution to holders of Class B common stock after payment of all of our prior obligations, including any then outstanding Preferred Stock, in the manner described in "Distributions Upon a Liquidation."

Registration Rights. The owners of Class B common stock do not have any registration rights under the terms of the Registration Rights Agreement. Pursuant to the Stockholders Agreement, we intend to file shelf registration statement(s) to register shares of common stock issued in connection with one or more Class B Exchanges. See "Class B Exchange Shelf Registration Statements."

Other Matters. The holders of our Class B common stock will have no preemptive rights, and our Class B common stock will not be subject to further calls or assessments by us other than upon certain termination of employment as described above under "Management Executive Compensation Treatment of Equity Awards." There are no redemption or sinking fund provisions applicable to our Class B common stock. During the first five business days of June of each year, commencing in 2017, but prior to any capital transaction where the MOIC is at least 1.0, any employee who owns Class B common stock (other than our chief executive officer or chief financial officer) and who exhibits sufficient financial need (as determined by the chief executive officer in good faith) may request that a portion of his Class B common stock be repurchased by us at the then fair market value, provided that such repurchases shall not (i) during any fiscal year, exceed $15 million in the aggregate or represent more than 12.5% of such employee's Class B common stock, (ii) cause more than 25% of such employee's Class B common stock to have been so repurchased, or (iii) be consummated if the chief executive officer determines in good faith that such repurchases would not be in our best interests.

Preferred Stock

For so long as the Negative Control Condition is satisfied, our Board may, by a Special Board Approval, and in the event the Negative Control Condition is no longer satisfied, our Board may by a majority vote, issue, from time to time, up to an aggregate of shares of preferred stock in one or more series and to fix or alter the designations, preferences, rights and any qualifications, limitations or restrictions of the shares of each such series thereof, including the dividend rights, dividend rates,

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conversion rights, voting rights, terms of redemption (including sinking fund provisions), redemption prices, liquidation preferences and the number of shares constituting any series or designations of such series. See "Certain Relationships and Related Party Transactions Stockholders Agreement" and " Certain Anti-Takeover, Limited Liability and Indemnification Provisions." Our Board may authorize the issuance of preferred stock with voting or conversion rights that could adversely affect the voting power or other rights of the holders of common stock. The issuance of preferred stock, while providing flexibility in connection with possible future financings and acquisitions and other corporate purposes could, under certain circumstances, have the effect of delaying, deferring or preventing a change in control of us and might affect the market price of our common stock. See " Certain Anti-Takeover, Limited Liability and Indemnification Provisions."

Distributions Upon a Liquidation

Upon a liquidation or dissolution of our company, whether voluntary or involuntary, or upon the consummation of certain change of control transactions with respect to us and our subsidiaries (taken as a whole), the proceeds from such liquidation, dissolution or change of control transaction will be distributed to the holders of common stock and the holders of Class B common stock as follows:

First, to each holder of common stock, its *pro rata* portion of such proceeds until each Legacy Class A Stockholder has recouped the amount of capital invested by such Legacy Class A Stockholder or its predecessor in interest in EP Energy Corporation and EPE Acquisition ("Invested Capital");

Second, to the holders of Class B common stock, a portion of such proceeds equal to 3/97ths of the amount of any Preferred Return (as defined below) paid to the Legacy Class A Stockholders prior to the occurrence of such liquidation, dissolution or change of control transaction;

Third, (i) 97% of the remaining proceeds to the holders of common stock until each Legacy Class A Stockholder has received a 5% preferred return on its Invested Capital ("Preferred Return"), and (ii) 3% of such remaining proceeds to the holders of Class B common stock *pro rata*;

Fourth, the remaining proceeds after the foregoing distributions have been made shall be distributed among the holders of common stock and the holders of Class B common stock as follows:

(a) the holders of common stock *pro rata*, the amount of such remaining proceeds not otherwise distributed to the holders of Class B common stock pursuant to (b) below; and

(b) to the holders of Class B common stock *pro rata*, a cumulative portion of the aggregate amount of the net return on investment received by the Legacy Class A Stockholders after taking into account costs and expenses incurred in connection with generating such return in excess of the total Invested Capital ("Profits") as set forth in the table below, based on the MOIC following such liquidation, dissolution or change of control transaction and expressed as a percentage of Profits; provided, that if such remaining proceeds described in this fourth bullet are insufficient to pay to the holders of Class B common stock such amount, then the holders of Class B common stock will instead be entitled to receive 50% of such remaining proceeds.

MOIC	Portion of Profits
$1.00 \leq \text{MOIC} \leq 1.50$	3.5% of Profits
$1.50 < \text{MOIC} \leq 2.25$	6.5% of Profits* + 3.5% of Profits
MOIC > 2.25	6.0% of Profits** + 6.5% of Profits* + 3.5% of Profits

* The calculation of Profits, solely for this purpose, is based on the amount of proceeds received by the Legacy Class A Stockholders in excess of the total Invested Capital multiplied by 1.50.

** The calculation of Profits, solely for this purpose, is based on the amount of proceeds received by the Legacy Class A Stockholders in excess of the total Invested Capital multiplied by 2.25.

Distributions of such proceeds to holders of Class B common stock will not exceed 8.5% of the aggregate Profits distributed to the Class A Stockholders and the Class B Stockholders and no distributions of such proceeds will be made to the holders of Class B common stock unless MOIC is at least 1.0.

Class B Exchange

Upon any sale of shares of common stock by the Specified Stockholders where the net return on Invested Capital to the Specified Stockholders after taking into account costs and expenses incurred in connection with generating such return (but only to the extent not reimbursed by us pursuant to the Stockholders Agreement) ("Specified MOIC") is at least 1.0 (a "Specified Sale"), we will exchange with each holder of Class B common stock a number of shares of Class B common stock for a number of newly issued shares of common stock in such amount and in the manner described below (a "Class B Exchange").

Number of Shares of Class B Common Stock Exchanged

In connection with each Class B Exchange, we will exchange with the holders of Class B common stock the consideration described below for a specified number of shares of Class B common stock such that following the exchange, the number of shares of Class B common stock will equal the Specified Percentage (as defined below) of the number of shares of Class B common stock owned prior to the first sale of common stock by the Specified Stockholders (the "First Sale"). The "Specified Percentage" is a percentage equal to the number of shares of common stock held by the Specified Stockholders after the First Sale divided by the number of shares of common stock held by the Specified Stockholders prior to the First Sale. For example, if the Specified Stockholders sold 20 out of 100 shares of common stock in a Specified Sale and had 80 shares of common stock remaining, the Specified Percentage would equal 80% and the total number of shares of Class B common stock held by the holders of Class B common stock following the Class B Exchange must be equal to 80% of the total number of shares of Class B common stock held by the holders of Class B common stock prior to the First Sale.

Class B Consideration

The aggregate value of the shares of common stock issuable in connection with a Class B Exchange (the "Class B Consideration") will equal:

3/97ths of any of the 5% preferred return on Invested Capital with respect to the Specified Stockholders to the extent received by the Specified Stockholders prior to the consummation of the related Specified Sale; *plus*

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3% of the net return on investment received by the Specified Stockholders after taking into account costs and expenses incurred in connection with generating such return (but only to the extent not reimbursed by us pursuant to the Stockholders Agreement) in excess of the total Invested Capital with respect to the Specified Stockholders ("Specified Profits") after the Specified Stockholders have recouped their Invested Capital, less the amount described in the first bullet above; *plus*

an amount of Specified Profits equal to a cumulative portion of the Specified Profits as set forth in the table below, based on the Specified MOIC following such Specified Sale and expressed as a percentage of Specified Profits; *plus*

an amount equal to (i) the aggregate of the amounts described in the preceding three bullets, (i) *multiplied* by (ii) a fraction, the numerator of which is the number of shares of common stock held by the Legacy Class A Stockholders immediately prior to the First Sale and the denominator of which is the total number of shares of common stock held by the Specified Stockholders as of immediately prior to the First Sale, *minus* (iii) the aggregate of the amounts described in the preceding three bullets.

Specified MOIC	Portion of Specified Profits
1.00 ≤ Specified MOIC ≤ 1.50	3.5% of Specified Profits
1.50 < Specified MOIC ≤ 2.25	6.5% of Specified Profits* + 3.5% of Specified Profits
Specified MOIC > 2.25	6.0% of Specified Profits** + 6.5% of Specified Profits* + 3.5% of Specified Profits

* The calculation of Specified Profits, solely for this purpose, is based on the amount of proceeds received by the Specified Stockholders in excess of the Invested Capital with respect to the Specified Stockholders multiplied by 1.50.

** The calculation of Specified Profits, solely for this purpose, is based on the amount of proceeds received by the Specified Stockholders in excess of the Invested Capital with respect to the Specified Stockholders multiplied by 2.25.

Number of shares of common stock issuable in a Class B Exchange

The total number of shares of common stock to be issued to the holders of Class B common stock in connection with a Class B Exchange shall be equal to the Class B Consideration, *divided* by the average per share closing price of the common stock for the five consecutive trading days immediately prior to the Class B Exchange. No fractional shares of common stock will be issued in connection with a Class B Exchange and each holder of Class B common stock will receive a cash payment in lieu of such fractional share of common stock based on the foregoing per share price. Upon the consummation of a Class B Exchange, we shall cancel the shares of Class B common stock received in such Class B Exchange.

Limitations on Class B Exchange

In no event shall the Class B Consideration exceed 8.5% of the Specified Profits and no Class B Exchange shall be consummated until the consummation of a Specified Sale. The amount of the Class B Consideration will be offset by amounts previously received by such stockholders in respect of their shares of Class B common stock.

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Shelf Registration Statements

Pursuant to the Stockholders Agreement, the shares of common stock issued in a Class B Exchange must be freely transferable under federal securities laws by the holders. In connection with such Class B Exchanges, we intend to file one or more shelf registration statements under the Securities Act covering newly issued shares of common stock pursuant to such Class B Exchanges. Accordingly, shares of our common stock registered under such shelf registration statement(s) may become available for sale in the open market upon the completion of such exchanges, subject to Rule 144 limitations applicable to our affiliates.

Certain Anti-Takeover, Limited Liability and Indemnification Provisions

Certain provisions in our Second Amended and Restated Certificate of Incorporation, Amended and Restated Bylaws and the Stockholders Agreement summarized below may be deemed to have an anti-takeover effect and may delay, deter or prevent a tender offer or takeover attempt that a stockholder might consider to be in its best interests, including attempts that might result in a premium being paid over the market price for the shares held by stockholders.

"Blank Check" Preferred Stock. Our Second Amended and Restated Certificate of Incorporation provides that, for so long as the Negative Control Condition is satisfied, our Board may by a Special Board Approval, and in the event the Negative Control Condition is no longer satisfied, our Board may by a majority vote, issue shares of Preferred Stock. See "Related Party Transactions Stockholders Agreement" and "Certain Relationships and Related Party Transactions Stockholders Agreement Consent Rights." Preferred Stock could be issued by our Board to increase the number of outstanding shares making a takeover more difficult and expensive. See " Preferred Stock."

No Cumulative Voting. Our Second Amended and Restated Certificate of Incorporation provides that stockholders do not have the right to cumulative votes in the election of directors.

Removal of Directors; Vacancies. Each of the Sponsors, for so long as it beneficially owns certain percentages of their current ownership of common stock as of the Effective Time, will have the right to designate a certain number of directors, and each Legacy Class A Stockholder has agreed to vote its shares of common stock in favor of such designee. Each of the Sponsors shall have the sole right to remove any director designated by it, with or without cause, and to fill any vacancy caused by the removal of any such director. If any Sponsor has lost its right to designate the applicable director nominee and the Legacy Class A Stockholders hold more than 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. For so long as the Sponsors or a majority-in-interest of the Legacy Class A Stockholders, as applicable, have the right to designate directors, the nominating committee of the Board 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. Subject to the exceptions described above, directors may be removed only for cause, and only by the affirmative vote of the holders of Class A Stock that together hold at least two-thirds of the voting power entitled to vote in any annual election of directors or class of directors; *provided*, *however*, that for so long as the Legacy Class A Stockholders beneficially own more than 50% of the outstanding common stock, directors may be removed only for cause, and only by the affirmative vote of the holders of Class A Stock that together hold at least a majority of the voting power entitled to vote in any annual election of directors or class of directors. See "Certain Relationships and Related Party Transactions Stockholders Agreement."

Stockholder Action by Written Consent. Our Second Amended and Restated Certificate of Incorporation provides that for so long as the Legacy Class A Stockholders beneficially own more than

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50% of the outstanding shares of our common stock, any action required to be or that may be taken at any meeting of stockholders may be taken without a meeting, without prior notice and without a vote, if and only if a consent in writing, setting forth the action so taken, shall be signed by the stockholders having not less than the minimum number of votes necessary to take such action.

Classified Board. Our Second Amended and Restated Certificate of Incorporation, Amended and Restated Bylaws and Stockholders Agreement provide that following the Effective Time, our Board will have three classes of directors:

Class I shall consist of two directors designated by Apollo, one director designated by Riverstone and one independent director designated by Apollo, each of whom shall serve an initial one-year term;

Class II shall consist of one director designated by Apollo, one director designated by KNOC, one director designated by Access and one independent director designated by Riverstone, each of whom shall serve an initial two -year term; and

Class III shall consist of two directors designated by Apollo, one director designated by Riverstone, one independent director designated by Apollo and our Chief Executive Officer, each of whom shall serve an initial three-year term.

For so long as the Negative Control Condition is satisfied, the number of directors on our Board may be fixed only by Special Board Approval. If the Negative Control Condition is no longer satisfied, the number of directors on our Board may be fixed by a majority of the Board.

Advance Notice Requirements for Stockholder Proposals and Director Nominations. Our Amended and Restated Bylaws provide that stockholders seeking to bring business before an annual meeting of stockholders, or to nominate candidates for election as directors at an annual meeting of stockholders, must provide timely notice thereof in writing. To be timely, a stockholder's notice generally must be delivered to and received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary of the preceding year's annual meeting; provided, that, in the event that the date of such meeting is advanced more than 30 days prior to, or delayed by more than 60 days after, the anniversary of the preceding year's annual meeting of our stockholders, a stockholder's notice to be timely must be so delivered not earlier than the close of business on the 120th day prior to such meeting and not later than the close of business on the later of the 90th day prior to such meeting or, if the first public announcement of the date of such annual meeting is less than 100 days prior to the date of such annual meeting, the 10th day following the day on which public announcement of the date of such meeting is first made. Our Amended and Restated Bylaws also specify certain requirements as to the form and content of a stockholder's notice. These provisions may preclude stockholders from bringing matters before an annual meeting of stockholders or from making nominations for directors at an annual meeting of stockholders.

Special Meetings of Stockholders. Subject to the rights of the Preferred Stock, special meetings of our stockholders may be called only by a majority of the Board pursuant to a resolution approved by the Board and business transacted at any special meeting of stockholders shall be limited to the purposes stated in the notice of such special meeting.

Special Board Approval. For so long as the Negative Control Condition is satisfied, certain of our significant business decisions require Special Board Approval, including the issuance of Preferred Stock. See "Certain Relationships and Related Party Transactions Stockholders Agreement" and "Certain Relationships and Related Party Transactions Consent Rights."

Limitation of Officer and Director Liability and Indemnification Arrangements. Our Second Amended and Restated Certificate of Incorporation limits the liability of our directors to the maximum extent permitted by Delaware law. However, if Delaware law is amended to authorize corporate action

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further limiting or eliminating the personal liability of directors, then the liability of our directors will be limited or eliminated to the fullest extent permitted by Delaware law, as so amended.

Our Second Amended and Restated Certificate of Incorporation provides that we will, from time to time, to the fullest extent permitted by law, indemnify our directors, officers and Board observers against all liabilities and expenses in any suit or proceeding, arising out of their status as an officer or director or their activities in these capacities. We also will indemnify any person who, at our request, is or was serving as a director, officer, trustee, employee or agent of another corporation or of a partnership, joint venture, trust or other enterprise, including service with respect to employee benefit plans maintained or sponsored by us.

The right to be indemnified will include the right of an officer or a director to be paid expenses, including attorneys' fees, in advance of the final disposition of any proceeding, provided that, if required by law, we receive an undertaking to repay such amount if it will be determined that he or she is not entitled to be indemnified.

Our Board may take certain action it deems necessary to carry out these indemnification provisions, including purchasing insurance policies. Neither the amendment nor the repeal of these indemnification provisions, nor the adoption of any provision of our Second Amended and Restated Certificate of Incorporation inconsistent with these indemnification provisions, will eliminate or reduce any rights to indemnification relating to such person's status or any activities prior to such amendment, repeal or adoption.

We may enter into separate indemnification agreements with each of our directors and executive officers, which may be broader than the specific indemnification provisions contained in Delaware law. These indemnification agreements may require us, among other things, to indemnify our directors and officers against liabilities that may arise by reason of their status or service as directors or officers, other than liabilities arising from willful misconduct. These indemnification agreements may also require us to advance any expenses incurred by the directors or officers as a result of any proceeding against them as to which they could be indemnified and to obtain directors' and officers' insurance, if available on reasonable terms.

Currently, to our knowledge, there is no pending litigation or proceeding involving any of our directors, officers, employees or agents in which indemnification by us is sought, nor are we aware of any threatened litigation or proceeding that may result in a claim for indemnification.

Insofar as indemnification for liabilities arising under the Securities Act may be permitted for our directors, officers and controlling persons under the foregoing provisions or otherwise, we have been informed that, in the opinion of the SEC, such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable.

We believe these provisions will assist in attracting and retaining qualified individuals to serve as directors and officers.

Delaware Anti-Takeover Law

We have elected to be exempt from the restrictions imposed under Section 203 of the DGCL. Section 203 of the DGCL provides that, subject to exception specified therein, an "interested stockholder" of a Delaware corporation shall not engage in any "business combination," including general mergers or consolidations or acquisitions of additional shares of the corporation, with the

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corporation for a three-year period following the time that such stockholder becomes an interested stockholder unless:

- prior to such time, the board of directors of the corporation approved either the business combination or the transaction which resulted in the stockholder becoming an interested stockholder;

- upon consummation of the transaction which resulted in the stockholder becoming an "interested stockholder," the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced (excluding specified shares); or

- on or subsequent to such time, the business combination is approved by the board of directors of the corporation and authorized at an annual or special meeting of stockholders, and not by written consent, by the affirmative vote of at least two-thirds of the outstanding voting stock not owned by the interested stockholder.

Under Section 203, the restrictions described above also do not apply to specified business combinations proposed by an interested stockholder following the announcement or notification of one of specified transactions involving the corporation and a person who had not been an interested stockholder during the previous three years or who became an interested stockholder with the approval of a majority of the corporation's directors, if such transaction is approved or not opposed by a majority of the directors who were directors prior to any person becoming an interested stockholder during the previous three years or were recommended for election or elected to succeed such directors by a majority of such directors.

Except as otherwise specified in Section 203, an "interested stockholder" is defined to include:

- any person that is the owner of 15% or more of the outstanding voting stock of the corporation, or is an affiliate or associate of the corporation and was the owner of 15% or more of the outstanding voting stock of the corporation at any time within three years immediately prior to the date of determination; and

- the affiliates and associates of any such person.

Under some circumstances, Section 203 makes it more difficult for a person who is an interested stockholder to effect various business combinations with us for a three-year period.

Amendment of Our Second Amended and Restated Certificate of Incorporation

For so long as the Negative Control Condition is satisfied, the Second Amended and Restated Certificate of Incorporation may be amended with a Special Board Approval and the affirmative vote of holders of at least 80% of the outstanding shares of common stock entitled to vote thereon. If the Negative Control Condition is no longer satisfied, the Second Amended and Restated Certificate of Incorporation may be amended by the affirmative vote of at least 90% of the outstanding shares of common stock entitled to vote thereon and by the vote of the holders of a majority of our Board.

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 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 does not conflict with the Stockholders Agreement and to give effect to the provisions of the Stockholders Agreement.

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Amendment of Our Amended and Restated Bylaws

For so long as the Negative Control Condition is satisfied, the Amended and Restated Bylaws may be amended with a Special Board Approval and the affirmative vote of holders of at least 80% of the outstanding shares of common stock entitled to vote thereon. If the Negative Control Condition is no longer satisfied, the Amended and Restated Certificate of Bylaws may be amended by the affirmative vote of at least 90% of the outstanding shares of common stock entitled to vote thereon and by the vote of the holders of a majority of our Board.

The Stockholders Agreement further provides that each of the Legacy Stockholders will not vote to amend or modify any provision of our 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 Amended and Restated Bylaws do not conflict with the Stockholders Agreement and to give effect to the provisions of the Stockholders Agreement.

Corporate Opportunity

Under our Second Amended and Restated Certificate of Incorporation, to the extent permitted by law:

- any Covered Person has the right to, and has no duty to abstain from, exercising such right to, conduct business with any business that is competitive or in the same line of business as the us, do business with any of our clients or customers, or invest or own any interest publicly or privately in, or develop a business relationship with, any business that is competitive or in the same line of business as us;

- if a Covered Person acquires knowledge of a potential transaction that could be a corporate opportunity, he has no duty to offer such corporate opportunity to us; and

- we have renounced any interest or expectancy in, or in being offered an opportunity to participate in, such corporate opportunities.

Transfer Agent and Registrar

Computershare Trust Company, N.A. is the transfer agent and registrar for our common stock.

Listing

We intend to apply to list our common stock on the NYSE under the symbol "EPE."

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DESCRIPTION OF CERTAIN INDEBTEDNESS

The following sets forth a summary of the terms of certain of our indebtedness. This summary is not a complete description of all the terms of the agreements governing the indebtedness and is qualified in its entirety by reference to the complete text of the agreements, copies of which have been filed or incorporated by reference as exhibits to the registration statement of which this prospectus forms a part.

The RBL Facility

General. In connection with the Acquisition, EP Energy LLC, as borrower, entered into a $2,000 million reserve-based borrowing base revolving credit facility (the "RBL Facility") with JPMorgan Chase Bank, N.A. as the administrative agent, which will mature on May 24, 2017. The RBL Facility provides for revolving loans, swing line loans and letters of credit. After completing a borrowing base redetermination in March 2013, the aggregate amount of the RBL Facility was increased to $2,500 million.

In August 2013, EP Energy LLC completed its borrowing base redetermination, maintaining a borrowing base at $2.5 billion.

As of August 31, 2013, we had $175 million of borrowings outstanding under the RBL Facility, which bear interest at LIBOR plus 1.5%. After taking into account outstanding letters of credit, there was $2,318 million of additional borrowing capacity under the RBL Facility. Upon completion of this offering, we will have $2.5 billion available for borrowing under the RBL Facility.

Interest Rates and Fees. Under the RBL Facility, we have a choice of borrowing at an interest rate equal to either an alternate base rate or the then-current LIBOR, in each case, plus an applicable margin. The applicable margin varies depending on the percentage of our borrowing base utilized at a given time and ranges from 150 to 250 basis points per annum for LIBOR based borrowings and ranges from 50 to 150 basis points per annum for base rate borrowings.

In addition to paying interest on outstanding principal under the RBL Facility, we are required to pay a commitment fee to the lenders in respect of the unutilized commitments. The commitment fee rate ranges from 37.5 to 50 basis points per annum based on our borrowing base usage at a given time.

Prepayments and Adjustments of the Borrowing Base. The borrowing base will be redetermined semi-annually on April 30th and October 31st of each year. In addition, the borrower may, no more than twice a year, and the lenders may, no more than once a year, elect to cause an interim redetermination of the borrowing base between the semi-annually scheduled redeterminations. If following a scheduled or interim redetermination of the borrowing base the aggregate amount of outstanding revolving loans, swingline loans and letters of credit exceeds the borrowing base, we will be required to elect within 10 business days to (i) within 30 days after such election, provide additional collateral having a borrowing base value sufficient to eliminate the deficiency; (ii) within 30 days after such election, prepay the loans (or cash collateralize the letters of credit) in an amount sufficient to eliminate such deficiency; (iii) prepay such deficiency in six equal monthly installments beginning on the 30th day after our receipt of notice of the deficiency from the administrative agent; or (iv) undertake a combination of clauses (i), (ii) and (iii); provided that any such deficiency must be cured prior to the maturity date of the RBL Facility.

If the borrowing base is reduced as a result of the incurrence of certain debt, early monetization or termination of hedge positions (above a certain agreed-upon threshold) or disposition of borrowing base assets (above a certain agreed-upon threshold) and the aggregate amount of outstanding revolving loans, swingline loans and letters of credit exceeds such reduced borrowing base, we are required to prepay the loans (or cash collateralize letters of credit) in an amount sufficient to eliminate such

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deficiency within two business days following receipt of the RBL Facility administrative agent's written notice of such deficiency.

Guarantees and Security. All obligations under the RBL Facility are fully and unconditionally guaranteed on a joint and several basis by, subject to certain exceptions, all of EP Energy LLC's existing and future direct and indirect wholly owned material domestic restricted subsidiaries, referred to collectively as guarantors (together with EP Energy LLC, referred to as "credit parties"). All obligations under the RBL Facility, and the guarantees of those obligations, are secured:

- on a first-priority basis by a perfected pledge of all of EP Energy LLC's capital stock and all of the capital stock of each direct, wholly owned, domestic, material restricted subsidiary held by the credit parties;

- on a first-priority basis by perfected real property mortgages on not less than 80% of the PV-10 value of the proved oil and gas reserves included in the borrowing base under the RBL Facility;

- on a first-priority basis by a perfected security interest in substantially all other tangible (other than real property and other oil and gas properties) and intangible assets of the credit parties (together with the collateral described in the preceding sentences, collectively referred to as the "RBL Facility Priority Collateral"); and

- on a second-priority basis by a perfected security interest in the Secured Notes/Term Loan Priority Collateral described below under "Senior Secured Term Loans."

The obligations under the RBL Facility are also guaranteed by EPE Holdings, LLC ("EPE Holdings"), the direct parent of EP Energy LLC. EPE Holdings' guarantee is limited recourse to the equity interests of EP Energy LLC owned by EPE Holdings.

Restrictive Covenants and Other Matters. The RBL Facility contains restrictive covenants that may limit EP Energy LLC's ability and the ability of its restricted subsidiaries to, among other things, (i) incur additional indebtedness; (ii) create liens; (iii) engage in mergers or consolidations; (iv) change our lines of business; (v) sell or transfer assets; (vi) pay dividends and distributions or repurchase the borrower's capital stock; (vii) amend material agreements governing our subordinated indebtedness; (viii) prepay, repay or repurchase certain junior indebtedness; (ix) engage in transactions with affiliates; (x) make investments, acquisitions, loans and advances; and (xi) enter into certain commodity and other regulated non-commodity hedging agreements. Each of these covenants is subject to customary or agreed-upon exceptions, baskets and thresholds.

In addition, the RBL Facility requires EP Energy LLC to maintain a ratio of its consolidated total debt, net of unrestricted cash and cash equivalents, to consolidated trailing 12-month EBITDAX (as defined in the credit agreement governing the RBL Facility) of not more than 5.0 to 1.0, with a step-down to 4.75 to 1.0 one year after entering into the RBL Facility and a further step down to 4.5 to 1.0 two years after entering into the RBL Facility and thereafter.

The credit agreement governing the RBL Facility also contains certain other customary affirmative covenants and events of default, subject to customary or agreed-upon exceptions, baskets and thresholds (including equity cure provisions).

Senior Secured Term Loans

Overview. In connection with the Acquisition, EP Energy LLC, as borrower, entered into a $750 million aggregate principal amount (the "original term loans") senior secured term loan facility with Citibank, N.A. as the administrative and collateral agent, which will mature on May 24, 2018. In August 2012 and May 2013, EP Energy LLC completed repricing amendments of the term loan facility that reduced the LIBOR floor and applicable margin applicable to the original term loans. In October 2012, EP Energy LLC obtained $400 million aggregate principal amount of incremental term loans (the "incremental term loans") under the term loan facility pursuant an incremental facility amendment, which will mature on April 30, 2019. We refer to the original term loans and the incremental term loans as our "senior secured term loans."

On August 16, 2013, we prepaid $250 million aggregate principal amount of the original term loans and $250 million aggregate principal amount of the incremental term loans. As of August 16, 2013, we had $650 million outstanding aggregate principal amount of senior secured term loans.

Interest Rates. The original term loans bear interest, at our option, at a rate equal to the alternate base rate plus an applicable margin of 3.75% or the then-current LIBOR, subject to a 0.75% floor, plus an applicable margin of 2.75%. The incremental term loans bear interest, at our option, at a rate equal to the alternate base rate plus an applicable margin of 4.50% or the then-current LIBOR, subject to a 1.00% floor, plus an applicable margin of 3.50%.

Prepayments. The original term loans are prepayable at any time without premium or penalty; provided that there will be a 1.00% prepayment premium in connection with any repricing of the original term loans that reduces the interest rate prior to November 24, 2013. The incremental terms loans are prepayable at any time without premium or penalty; provided that there will be a 1.00% prepayment premium in connection with any repricing of the incremental term loans that reduces the interest rate prior to October 31, 2013.

We are also required to offer to prepay our senior secured term loans, subject to customary reinvestment rights and other customary exceptions, with (a) the net cash proceeds from any non-ordinary course disposition of any Secured Notes/Term Loan Priority Collateral and (ii) the net cash proceeds from any non-ordinary-course asset sale of RBL Facility Priority Collateral in excess of the amount required to be paid to the lenders under the RBL Facility or the holders of certain other indebtedness. We are also required to offer to prepay our senior secured term loans following the occurrence of a change of control at 101% of the outstanding principal amount thereof, plus accrued and unpaid interest to the date of repayment, on terms consistent with those applicable to the senior secured notes.

Guarantees and Security. All obligations under our senior secured term loans are fully and unconditionally guaranteed on a joint and several basis by each of the guarantors under the RBL Facility, and all such obligations and guarantees are secured (i) on a first-priority basis by a perfected pledge of the capital stock of all first-tier foreign subsidiaries that are directly owned by EP Energy LLC or any guarantor (which pledge will be limited to 65% of the voting capital stock and 100% of the non-voting capital stock of such subsidiary) (referred to as the "Secured Notes/Term Loan Priority Collateral") and (ii) on a second-priority basis by a security interest in the RBL Facility Priority Collateral. The senior secured term loans share equally with our senior secured notes in the liens on the Secured Notes/Term Loan Priority Collateral and the RBL Facility Priority Collateral. The agent for the senior secured term loan and the trustee for the senior secured notes have entered into an intercreditor agreement governing the relationship between the lenders of the senior secured term loan and holders of the senior secured notes as well as holders of any other indebtedness that is secured on a pari passu basis with the senior secured notes.

Restrictive Covenants and Other Matters. The loan agreement governing our senior secured term loans contains restrictive covenants that may restrict EP Energy LLC's ability and the ability of its restricted subsidiaries to, among other things, (i) incur additional indebtedness, (ii) make certain investments, loan, and advances, (iii) consolidate, merge, sell or otherwise dispose of all or any part of its assets or to purchase, lease or otherwise acquire all or any substantial part of assets of any other person, (iv) prepay subordinated indebtedness, pay dividends or make distributions or other restricted payments, (v) create liens on certain assets and (vi) enter into certain transactions with affiliates, in each case, consistent with comparable provisions applicable to the senior secured notes. Each of these covenants is subject to customary or agreed-upon exceptions, baskets and thresholds. The loan agreement governing our senior secured term loans does not contain any financial maintenance covenant.

The loan agreement governing our senior secured term loans also contains certain other customary affirmative covenants and events of default, subject to customary or agreed-upon exceptions, baskets and thresholds.

Senior Secured Notes and Senior Notes

EP Energy LLC and Everest Acquisition Finance Inc., as issuers, have $750 million outstanding aggregate principal amount of 6.875% senior secured notes due 2019 (the "senior secured notes"), $2,000 million outstanding aggregate principal amount of 9.375% senior notes due 2020 (the "2020 senior notes") and $350 million outstanding aggregate principal amount of 7.750% senior notes due 2022 (the "2022 senior notes" and, together with the 2020 senior notes, the "senior notes"). The senior secured notes and 2020 senior notes were issued in connection with the financing of the Acquisition and the 2022 senior notes were issued on August 8, 2012 to repay a portion of the borrowings under the RBL Facility, as well as for other general corporate purposes.

Maturity and Interest Payment Dates. The senior secured notes will mature on May 1, 2019. The 2020 senior notes will mature on May 1, 2020. The 2022 senior notes will mature on September 1, 2022. Interest on the senior notes is payable semi-annually on May 1 and November 1 of each year in the case of the senior secured notes, May 1 and November of each year in the case of the 2020 senior notes and March 1 and September 1 of each year in the case of the 2022 senior notes.

Guarantee and Security. All of the senior secured notes and senior notes are fully and unconditionally guaranteed on a joint and several basis by each of the guarantors under the RBL Facility.

The obligations and guarantees under the senior secured notes are secured (i) on a first-priority basis by a security interest in the Secured Notes/Term Loan Priority Collateral and (ii) on a second-priority basis by a security interest in the RBL Facility Priority Collateral, that is in each case pari passu with the security interests securing our senior secured term loans.

Restrictive Covenants and Other Matters. The indentures governing the senior secured notes and senior notes contain restrictive covenants that may restrict EP Energy LLC's ability and the ability of its restricted subsidiaries to, among other things, (i) incur additional indebtedness, (ii) make certain investments, loan, and advances, (iii) consolidate, merge, sell or otherwise dispose of all or any part of its assets or to purchase, lease or otherwise acquire all or any substantial part of assets of any other person, (iv) prepay subordinated indebtedness, pay dividends or make distributions or other restricted payments, (v) create liens on certain assets and (vi) enter into certain transactions with affiliates. Each of these covenants is subject to customary or agreed-upon exceptions, baskets and thresholds.

The indentures governing the senior secured notes and senior notes also contain customary events of default, subject to customary or agreed-upon exceptions, baskets and thresholds.

Upon the occurrence of a change of control, as defined in each of the applicable indentures, each holder has the right to require the issuers to repurchase some or all of such holder's senior notes at a purchase price in cash equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the repurchase date.

Optional Redemption. The issuers may redeem some or all of the senior secured notes at any time on or prior to May 1, 2015, at a redemption price equal to 100% of the aggregate principal amount of the senior secured notes to be redeemed, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date. On or after May 1, 2015, the issuers may also redeem some or all of the

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senior secured notes at the redemption prices specified in the indenture relating to the senior secured notes. At any time on or prior to May 1, 2015, the issuers may also redeem up to 35% of the original aggregate principal amount of the senior secured notes with the net cash proceeds of this offering and other equity offerings that are contributed to the issuers, at a redemption price equal to 106.875% of the aggregate principal amount of the senior secured notes to be redeemed, plus accrued and unpaid interest, if any, to the redemption date.

The issuers may redeem some or all of the 2020 senior notes at any time on or prior to May 1, 2016, at a redemption price equal to 100% of the aggregate principal amount of the 2020 senior notes to be redeemed, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date. On or after May 1, 2016, the issuers may also redeem some or all of the 2020 senior notes at the redemption prices specified in the indenture relating to the 2020 senior notes. At any time on or prior to May 1, 2016, the issuers may also redeem up to 35% of the original aggregate principal amount of the 2020 senior notes with the net cash proceeds of this offering and other equity offerings that are contributed to the issuers, at a redemption price equal to 109.375% of the aggregate principal amount of the notes to be redeemed, plus accrued and unpaid interest, if any, to the redemption date.

The issuers may redeem some or all of the 2022 senior notes at any time on or prior to September 1, 2017, at a redemption price equal to 100% of the aggregate principal amount of the 2022 senior notes to be redeemed, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date. On or after September 1, 2017, the issuers may also redeem some or all of the 2022 senior notes at the redemption prices specified in the indenture relating to the 2022 senior notes. At any time on or prior to September 1, 2017, the issuers may also redeem up to 35% of the original aggregate principal amount of the 2022 senior notes with the net cash proceeds of this offering and other equity offerings that are contributed to the issuers, at a redemption price equal to 107.750% of the aggregate principal amount of the 2022 senior notes to be redeemed, plus accrued and unpaid interest, if any, to the redemption date.

Senior PIK Toggle Notes

EPE Holdings and EP Energy BondCo Inc., as issuers, issued $350 million aggregate principal amount of 8.125%/8.875% Senior PIK Toggle Notes due 2017 (the "PIK notes"). The PIK notes were issued on December 21, 2012 and will mature on December 15, 2017. The net proceeds from the PIK notes were used to pay a distribution to the EPE Acquisition equity holders. The issuers may elect to pay interest on the PIK notes in one of the following three manners: (i) entirely in cash, (ii) entirely by increasing the principal amount of the outstanding notes or issuing new notes ("PIK interest"), or (iii) in cash on 50% of the outstanding principal amount of the notes and in PIK Interest on the remaining 50% of the outstanding principal amount of the notes. Cash interest on the PIK notes accrues at a rate of 8.125% per annum and PIK interest accrues at a rate of 8.875% per annum and is payable semi-annually on December 15 and June 15 of each year. As of August 31, 2013, the outstanding aggregate principal amount of PIK notes was $372 million.

The PIK notes are unsecured obligations of the issuers and are not guaranteed by EP Energy Corporation or any of its other subsidiaries.

The indenture governing the PIK notes contains restrictive covenants that may restrict EPE Holdings' ability and the ability of its restricted subsidiaries to, among other things, (i) incur additional indebtedness, (ii) make certain investments, loan, and advances, (iii) consolidate, merge, sell or otherwise dispose of all or any part of its assets or to purchase, lease or otherwise acquire all or any substantial part of assets of any other person, (iv) prepay subordinated indebtedness, pay dividends or make distributions or other restricted payments, (v) create liens on certain assets and (vi) enter into certain transactions with affiliates. Each of these covenants is subject to customary or agreed-upon exceptions, baskets and thresholds.

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The indenture governing the PIK notes also contain customary events of default, subject to customary or agreed-upon exceptions, baskets and thresholds.

Upon the occurrence of a change of control, as defined in the PIK note indenture, each holder has the right to require the issuers to repurchase some or all of such holder's PIK notes at a purchase price in cash equal to 101% of the principal amount thereof, plus accrued and unpaid interest, if any, to the repurchase date.

The issuers may redeem some or all of the PIK notes at any time on or prior to December 15, 2013, at a redemption price equal to 100% of the aggregate principal amount of the PIK notes to be redeemed, plus a make-whole premium and accrued and unpaid interest, if any, to the redemption date. On or after December 15, 2013, the issuers may also redeem some or all of the PIK notes at the redemption prices specified in the indenture relating to the PIK notes. At any time on or prior to December 15, 2013, the issuers may also redeem some or all of the PIK notes with the net cash proceeds of this offering and other equity offerings that are contributed to the issuers, at a redemption price equal to 102.000% of the aggregate principal amount of the PIK notes to be redeemed, plus accrued and unpaid interest, if any, to the redemption date.

As described under "Use of Proceeds," we intend to use a portion the proceeds from this offering to redeem all of the PIK notes.

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SHARES ELIGIBLE FOR FUTURE SALE

There has not been a public market for our common stock prior to this offering. We cannot predict the extent to which investor interest in us will lead to the development of an active trading market or how liquid that market might become. If an active trading market does not develop, you may have difficulty selling any of our common stock that you buy. The initial public offering price for the common stock will be determined by negotiations between us and the underwriters and may not be indicative of prices that will prevail in the open market following this offering. See "Underwriting." Consequently, you may be unable to sell our common stock at prices equal to or greater than the price you pay in this offering.

Sale of Restricted Shares

Upon completion of this offering, we will have an aggregate of shares of our common stock outstanding. Of these shares, shares of our common stock to be sold in this offering will be freely tradable without restriction or further registration under the Securities Act, except for any shares which may be acquired by any of our "affiliates" as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144. The remaining shares of our common stock outstanding will be restricted securities, as that term is defined in Rule 144, and may in the future be sold pursuant to an effective registration statement or under the Securities Act to the extent permitted by Rule 144 or any other available exemption under the Securities Act.

Omnibus Incentive Plan

Following the completion of this offering, we intend to file a registration statement on Form S-8 under the Securities Act with the SEC to register shares of our common stock issued or reserved for issuance under the Omnibus Incentive Plan. Subject to the expiration of any lock-up restrictions as described below and following the completion of any vesting periods, shares of our common stock issued under the Omnibus Incentive Plan, issuable upon the exercise of options granted or to be granted under the plan, will be freely tradable without restriction under the Securities Act, unless such shares are held by any of our affiliates.

Lock-up Agreements

Executive officers, directors and our stockholders have agreed not to sell or transfer any shares of our common stock for a period of days from the date of this prospectus, subject to certain exceptions and extensions. See "Underwriting" for a description of these lock-up provisions.

Rule 144

In general, under Rule 144 under the Securities Act, a person who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

All of our outstanding common stock before this offering is held by affiliates. A person who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares (when aggregated with sales by certain related parties) that does not exceed the greater of 1% of the then outstanding shares of our common stock (shares following this offering) or the average weekly trading volume of our common stock reported through the applicable stock exchange during the four calendar weeks preceding such sale. Such sales are also subject to

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certain manner of sale provisions, notice requirements and the availability of current public information about us.

Rule 701

In general, under Rule 701, any of our employees, directors, officers, consultants or advisors who purchases shares from us in connection with a compensatory stock or option plan or other written agreement before the effective date of this offering is entitled to sell such shares 90 days after the effective date of this offering in reliance on Rule 144, without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Registration Rights

Pursuant to the Registration Rights Agreement, we have granted the Legacy Class A Stockholders demand registration rights and/or incidental registration rights, in each case, with respect to certain shares of common stock owned by them. See "Certain Relationships and Related Party Transactions Registration Rights Agreement."

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MATERIAL U.S. FEDERAL INCOME TAX CONSEQUENCES TO NON-U.S. HOLDERS

The following discussion is a summary of the material U.S. federal income tax consequences to non-U.S. holders (as defined below) of the purchase, ownership and disposition of our common stock issued pursuant to this offering, but does not purport to be a complete analysis of all potential tax effects. The effects of other U.S. federal tax laws, such as estate and gift tax laws, and any applicable state, local or foreign tax laws are not discussed. This discussion is based on the Internal Revenue Code of 1986, as amended (the "Code"), Treasury Regulations promulgated thereunder, judicial decisions and published rulings and administrative pronouncements of the U.S. Internal Revenue Service (the "IRS") in effect as of the date of this offering. These authorities may change or be subject to differing interpretations. Any such change may be applied retroactively in a manner that could adversely affect a non-U.S. holder of our common stock. We have not sought and will not seek any rulings from the IRS regarding the matters discussed below. There can be no assurance the IRS or a court will not take a contrary position regarding the tax consequences of the purchase, ownership and disposition of our common stock.

This discussion is limited to non-U.S. holders that hold our common stock as a "capital asset" within the meaning of Section 1221 of the Code (generally property held for investment). This discussion does not address all U.S. federal income tax consequences relevant to a non-U.S. holder's particular circumstances, including the impact of the unearned income Medicare contribution tax. In addition, it does not address consequences relevant to non-U.S. holders subject to special rules, including, without limitation:

- U.S. expatriates and certain former citizens or long-term residents of the United States;
- persons subject to the alternative minimum tax;
- persons holding our common stock as part of a hedge, straddle or other risk reduction strategy or as part of a conversion transaction or other integrated investment;
- banks, insurance companies and other financial institutions;
- real estate investment trusts or regulated investment companies;
- brokers, dealers or traders in securities;
- "controlled foreign corporations," "passive foreign investment companies" and corporations that accumulate earnings to avoid U.S. federal income tax;
- S corporations, partnerships or other entities or arrangements treated as partnerships for U.S. federal income tax purposes;
- tax-exempt organizations or governmental organizations;
- persons deemed to sell our common stock under the constructive sale provisions of the Code;
- persons who hold or receive our common stock pursuant to the exercise of any employee stock option or otherwise as compensation; and
- tax-qualified retirement plans.

If a partnership (or other entity treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership will depend on the status of the partner, the activities of the partnership and certain determinations made at the partner level. Accordingly, partnerships holding our common stock and the partners in such partnerships should consult their tax advisors regarding the U.S. federal income tax consequences to them.

THIS DISCUSSION IS FOR INFORMATION PURPOSES ONLY AND IS NOT INTENDED AS TAX ADVICE. INVESTORS SHOULD CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE

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APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATIONS AS WELL AS ANY TAX CONSEQUENCES OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF OUR COMMON STOCK ARISING UNDER THE U.S. FEDERAL ESTATE OR GIFT TAX LAWS OR UNDER THE LAWS OF ANY STATE, LOCAL OR NON-U.S. TAXING JURISDICTION OR UNDER ANY APPLICABLE INCOME TAX TREATY.

Definition of a Non-U.S. Holder

For purposes of this discussion, a "non-U.S. holder" is any beneficial owner of our common stock that is neither a "U.S. holder' nor a partnership for U.S. federal income tax purposes. A U.S. holder is any of the following:

- an individual who is a citizen or resident of the United States;

- a corporation (or other entity taxable as a corporation for U.S. federal income tax purposes) created or organized under the laws of the United States, any state thereof, or the District of Columbia;

- an estate, the income of which is subject to U.S. federal income tax regardless of its source; or

- a trust that (1) is subject to the primary supervision of a U.S. court and the control of one or more United States persons (within the meaning of Section 7701(a)(30) of the Code) or (2) has made a valid election under applicable Treasury Regulations to continue to be treated as a United States person.

Distributions

We do not anticipate declaring or paying dividends to holders of our common stock in the foreseeable future. However, if we make distributions of cash or property on our common stock, such distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. Amounts not treated as dividends for U.S. federal income tax purposes will constitute a return of capital and first be applied against and reduce a non-U.S. holder's adjusted tax basis in its common stock, but not below zero. Any excess will be treated as capital gain and will be treated as described below in the section relating to the sale or disposition of our common stock.

Subject to the discussion below on backup withholding and foreign accounts, dividends paid to a non-U.S. holder of our common stock that are not effectively connected with the non-U.S. holder's conduct of a trade or business within the United States will be subject to U.S. federal withholding tax at a rate of 30% of the gross amount of the dividends (or such lower rate specified by an applicable income tax treaty).

Non-U.S. holders may be entitled to a reduction in or an exemption from withholding on dividends as a result of either (a) an applicable income tax treaty or (b) the non-U.S. holder holding our common stock in connection with the conduct of a trade or business within the United States and dividends being paid in connection with that trade or business. To claim such a reduction in or exemption from withholding, the non-U.S. holder must provide the applicable withholding agent with a properly executed (a) IRS Form W-8BEN claiming an exemption from or reduction of the withholding tax under the benefit of an income tax treaty between the United States and the country in which the non-U.S. holder resides or is established, or (b) IRS Form W-8ECI stating that the dividends are not subject to withholding tax because they are effectively connected with the conduct by the non-U.S. holder of a trade or business within the United States, as may be applicable. These certifications must be provided to the applicable withholding agent prior to the payment of dividends and must be updated periodically. Non-U.S. holders that do not timely provide the applicable withholding agent with the required certification, but that qualify for a reduced rate under an applicable income tax treaty, may

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obtain a refund of any excess amounts withheld under these rules by timely filing an appropriate claim for refund with the IRS.

Subject to the discussion below on backup withholding and foreign accounts, if dividends paid to a non-U.S. holder are effectively connected with the non-U.S. holder's conduct of a trade or business within the United States (and, if required by an applicable income tax treaty, the non-U.S. holder maintains a permanent establishment in the United States to which such dividends are attributable), then, although exempt from U.S. federal withholding tax (provided the non-U.S. holder provides appropriate certification, as described above), the non-U.S. holder will be subject to U.S. federal income tax on such dividends on a net income basis at the regular graduated U.S. federal income tax rates. In addition, a non-U.S. holder that is a corporation may be subject to a branch profits tax at a rate of 30% (or such lower rate specified by an applicable income tax treaty) on its effectively connected earnings and profits for the taxable year (and, if required by an applicable income tax treaty, that are attributable to a permanent establishment maintained by the corporate non-U.S. holder in the United States), as adjusted for certain items. Non-U.S. holders should consult their tax advisors regarding their entitlement to benefits under any applicable income tax treaty.

Sale or Other Taxable Disposition

Subject to the discussions below on backup withholding and foreign accounts, a non-U.S. holder will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

- the gain is effectively connected with the non-U.S. holder's conduct of a trade or business within the United States (and, if required by an applicable income tax treaty, the non-U.S. holder maintains a permanent establishment in the United States to which such gain is attributable);

- the non-U.S. holder is a nonresident alien individual present in the United States for 183 days or more during the taxable year of the disposition and certain other requirements are met; or

- our common stock constitutes a U.S. real property interest by reason of our status as a U.S. real property holding corporation (a "USRPHC") for U.S. federal income tax purposes.

Gain described in the first bullet point above will generally be subject to U.S. federal income tax on a net income basis at the regular graduated rates. A non-U.S. holder that is a foreign corporation also may be subject to a branch profits tax at a rate of 30% (or such lower rate specified by an applicable income tax treaty) of a portion of its effectively connected earnings and profits for the taxable year, as adjusted for certain items.

A non-U.S. holder described in the second bullet point above will be subject to U.S. federal income tax at a rate of 30% (or such lower rate specified by an applicable income tax treaty) on any gain derived from the disposition, which may be offset by certain U.S. source capital losses of the non-U.S. holder (even though the individual is not considered a resident of the United States) provided the non-U.S. holder has timely filed U.S. federal income tax returns with respect to such losses.

With respect to the third bullet point above, we believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, so long as our common stock is "regularly traded on an established securities market," a non-U.S. holder will be subject to U.S. federal income tax on any gain from a disposition of our common stock only if the non-U.S. holder actually or constructively holds or held (at any time during the shorter of the five-year period preceding the date of disposition or the holder's holding period) more than 5% of our common stock. If our common stock is not considered to be so traded, all non-U.S. holders would be subject to U.S. federal income tax on any gain from a disposition of our common stock and a 10% withholding tax would apply to the gross proceeds from the sale of our common stock by a non-U.S. holder. If any gain from a disposition is subject to U.S. federal income tax as described above, it will be taxed as if the non-U.S. holder were a U.S. resident and the non-U.S. holder would be required to file a U.S. tax return with respect to such gain.

Non-U.S. holders should consult their tax advisors regarding potentially applicable income tax treaties that may provide for different rules.

Information Reporting and Backup Withholding

A non-U.S. holder will not be subject to backup withholding with respect to payments of dividends on our common stock, provided the applicable withholding agent does not have actual knowledge or reason to know such holder is a United States person and the holder certifies its non-U.S. status, such as by providing a valid IRS Form W-8BEN or W-8ECI, or other applicable certification. However, information returns will be filed with the IRS in connection with any dividends on our common stock paid to the non-U.S. holder, regardless of whether any tax was actually withheld. Copies of these information returns may also be made available under the provisions of a specific treaty or agreement to the tax authorities of the country in which the non-U.S. holder resides or is established.

Information reporting and backup withholding may apply to the proceeds of a sale of our common stock within the United States, and information reporting may (although backup withholding generally will not) apply to the proceeds of a sale of our common stock outside the United States conducted through certain U.S.-related financial intermediaries, in each case, unless the beneficial owner certifies under penalty of perjury that it is a non-U.S. holder on IRS Form W-8BEN or other applicable form (and the payor does not have actual knowledge or reason to know that the beneficial owner is a United States person) or such owner otherwise establishes an exemption.

Backup withholding is not an additional tax. Any amounts withheld under the backup withholding rules may be allowed as a refund or a credit against a non-U.S. holder's U.S. federal income tax liability, provided the required information is timely furnished to the IRS.

Additional Withholding Tax on Payments Made to Foreign Accounts

Provisions commonly referred to as "FATCA" impose withholding taxes on certain types of payments made to non-U.S. financial institutions and certain other non-U.S. entities. Specifically, a 30% withholding tax may be imposed on dividends on, or gross proceeds from the sale or other disposition of, our common stock paid to a "foreign financial institution" or a "non-financial foreign entity" (each as defined in the Code), unless (1) the foreign financial institution undertakes certain diligence and reporting obligations, (2) the non-financial foreign entity either certifies it does not have any "substantial United States owners" (as defined in the Code) or furnishes identifying information regarding each substantial United States owner or (3) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules. If the payee is a foreign financial institution and is subject to the diligence and reporting requirements in (1) above, it must enter into an agreement with the U.S. Department of the Treasury requiring, among other things, that it undertake to identify accounts held by certain "specified United States persons" or "United States-owned foreign entities" (each as defined in the Code), annually report certain information about such accounts and withhold 30% on payments to non-compliant foreign financial institutions and certain other account holders. Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing FATCA may be subject to different rules.

Under the applicable Treasury Regulations, withholding under FATCA generally will apply to payments of dividends on our common stock made on or after July 1, 2014 and to payments of gross proceeds from the sale or other disposition of such stock on or after January 1, 2017.

Prospective investors should consult their tax advisors regarding the potential application of withholding under FATCA to their investment in our common stock.

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UNDERWRITING

Under the terms and subject to the conditions in an underwriting agreement dated the date of this prospectus, the underwriters named below have severally agreed to purchase, and we have agreed to sell to them the number of shares indicated below:

Name	Number of Shares
Total	

The underwriters and the representatives are collectively referred to as the "underwriters" and the "representatives," respectively. The underwriters are offering the shares of common stock subject to their acceptance of the shares from us and subject to prior sale. The underwriting agreement provides that the obligations of the several underwriters to pay for and accept delivery of the shares of common stock offered by this prospectus are subject to the approval of certain legal matters by their counsel and to certain other conditions. The underwriters are obligated to take and pay for all of the shares of common stock offered by this prospectus if any such shares are taken. However, the underwriters are not required to take or pay for the shares covered by the underwriters' option to purchase additional shares, as described below.

The underwriters initially propose to offer part of the shares of common stock directly to the public at the offering price listed on the cover page of this prospectus and part to certain dealers. After the initial offering of the shares of common stock, the offering price and other selling terms may from time to time be varied by the representatives. The offering of the shares by the underwriters is subject to receipt and acceptance and subject to the underwriters' right to reject any order in whole or in part.

We have granted to the underwriters an option, exercisable for 30 days from the date of this prospectus, to purchase up to additional shares of common stock at the public offering price listed on the cover page of this prospectus, less underwriting discounts and commissions and the per share amount, if any, of dividends declared by us and payable on the shares purchased by them from us other than by exercise of their option to purchase additional shares but not payable on the shares that are subject to that option.

To the extent the option is exercised, each underwriter will become obligated, subject to certain conditions, to purchase about the same percentage of the additional shares of common stock as the number listed next to the underwriter's name in the preceding table bears to the total number of shares of common stock listed next to the names of all underwriters in the preceding table.

The following table shows the per share and total public offering price, underwriting discounts and commissions, and proceeds before expenses to us. These amounts are shown assuming both no exercise and full exercise of the underwriters' option to purchase up to an additional shares of common stock.

		Total	
	Per Share	**No Exercise**	**Full Exercise**
Public offering price	$	$	$
Underwriting discounts and commissions to be paid by us	$	$	$
Proceeds, before expenses, to us	$	$	$

The estimated offering expenses payable by us, exclusive of the underwriting discounts and commissions, are approximately $ million.

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The underwriters have informed us that they do not intend sales to discretionary accounts to exceed 5% of the total number of shares of common stock offered by them.

We intend to apply to have our common stock listed on the NYSE under the trading symbol "EPE."

We and all of our directors and officers have agreed that, without the prior written consent of the underwriters, we and they will not, during the period ending days after the date of this prospectus:

- offer, pledge, sell, contract to sell, sell any option or contract to purchase, purchase any option or contract to sell, grant any option, right or warrant to purchase lend or otherwise transfer or dispose of, directly or indirectly, any shares of common stock or any securities convertible into or exercisable or exchangeable for shares of common stock;

- file any registration statement with the SEC relating to the offering of any shares of common stock or any securities convertible into or exercisable or exchangeable for common stock; or

- enter into any swap or other arrangement that transfers to another, in whole or in part, any of the economic consequences of ownership of the common stock,

whether any such transaction described above is to be settled by delivery of common stock or such other securities, in cash or otherwise. In addition, we and each such person agree that, without the prior written consent of the underwriters, it will not, during the period ending days after the date of this prospectus, make any demand for, or exercise any right with respect to, the registration of any shares of common stock or any security convertible into or exercisable or exchangeable for common stock.

The restrictions described in the immediately preceding paragraph do not apply to the sale of shares to the underwriters and are subject to other customary exceptions.

The day restricted period described in the preceding paragraph will be extended if:

- during the last 17 days of the day restricted period we issue an earnings release or material news event relating to us occurs, or

- prior to the expiration of the day restricted period, we announce that we will release earnings results during the 16 day period beginning on the last day of the day period

in which case the restrictions described in the preceding paragraph will continue to apply until the expiration of the 18 day period beginning on the issuance of the earnings release or the occurrence of the material news or material event.

In order to facilitate the offering of the common stock, the underwriters may engage in transactions that stabilize, maintain or otherwise affect the price of the common stock. Specifically, the underwriters may sell more shares than they are obligated to purchase under the underwriting agreement, creating a short position. A short sale is covered if the short position is no greater than the number of shares available for purchase by the underwriters under their option to purchase additional shares. The underwriters can close out a covered short sale by exercising their option to purchase additional shares or purchasing shares in the open market. In determining the source of shares to close out a covered short sale, the underwriters will consider, among other things, the open market price of shares compared to the price available under their option to purchase additional shares. The underwriters may also sell shares in excess of their option, to purchase additional shares creating a naked short position. The underwriters must close out any naked short position by purchasing shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of the common stock in the open market after pricing that could adversely affect investors who purchase in this offering. As an additional means of facilitating this offering, the underwriters may bid for, and purchase, shares of common stock in the open market to stabilize the price of the common stock. These activities may raise or maintain the market price of the common stock above independent market levels or prevent or retard a decline in the market price of the common stock. The underwriters are not required to engage in these activities and may end any of these activities at any time.

The underwriters may also impose a penalty bid. This occurs when a particular underwriter repays to the underwriters a portion of the underwriting discount received by it because the representatives have repurchased shares sold by or for the account of such underwriter in stabilizing or short covering transactions. We have agreed to indemnify the several underwriters, including their controlling persons, against certain liabilities, including liabilities under the Securities Act.

A prospectus in electronic format may be made available on websites maintained by one or more underwriters, or selling group members, if any, participating in this offering. The representatives may agree to allocate a number of shares of common stock to underwriters for sale to their online brokerage account holders. Internet distributions will be allocated by the representatives to underwriters that may make Internet distributions on the same basis as other allocations.

Pricing of the Offering

Prior to this offering, there has been no public market for our common stock. The initial public offering price was determined by negotiations between us and the representatives. Among the factors considered in determining the initial public offering price were our future prospects and those of our industry in general, our sales, earnings and certain other financial and operating information in recent periods, and the price-earnings ratios, price-sales ratios, market prices of securities and certain financial and operating information of companies engaged in activities similar to ours.

Selling Restrictions

European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a "Relevant Member State") an offer to the public of any shares of our common stock may not be made in that Relevant Member State, except that an offer to the public in that Relevant Member State of any shares of our common stock may be made at any time under the following exemptions under the Prospectus Directive, if they have been implemented in that Relevant Member State:

(a) to any legal entity that is a qualified investor as defined in the Prospectus Directive;

(b) to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the representatives for any such offer; or

(c) in any other circumstances falling within Article 3(2) of the Prospectus Directive, provided that no such offer of shares of our common stock shall result in a requirement for the publication by us or any underwriter of a prospectus pursuant to Article 3 of the Prospectus Directive.

For the purposes of this provision, (1) the expression an "offer to the public" in relation to any shares of our common stock in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and any shares of our common stock to be offered so as to enable an investor to decide to purchase any shares of our common stock, as the same may be varied in that Member State by any measure implementing the Prospectus Directive in

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that Member State, (2) the expression "Prospectus Directive" means Directive 2003/71/EC (and amendments thereto, including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member State), and includes any relevant implementing measure in the Relevant Member State, and (3) the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

United Kingdom

Each underwriter has represented and agreed that:

(a) it has only communicated or caused to be communicated and will only communicate or cause to be communicated an invitation or inducement to engage in investment activity (within the meaning of Section 21 of the FSMA) received by it in connection with the issue or sale of the shares of our common stock in circumstances in which Section 21(1) of the FSMA does not apply to us; and

(b) it has complied and will comply with all applicable provisions of the FSMA with respect to anything done by it in relation to the shares of our common stock in, from or otherwise involving the United Kingdom.

Hong Kong

The shares may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder.

Singapore

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the shares under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant

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person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

Japan

The securities have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

Affiliations

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities and other financial and non-financial activities and services. Certain of the underwriters and their respective affiliates have, from time to time, performed, and may in the future perform, various financial advisory and investment banking services for us, for which they have received or may receive customary fees and expenses. Certain of the underwriters or their affiliates may have an indirect ownership interest in us through various private equity funds, including funds affiliated with Apollo.

In the ordinary course of business, the underwriters and their respective affiliates may make or hold a broad array of investments, including serving as counterparties to certain derivative and hedging arrangements and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account or for the accounts of their customers, and such investment and securities activities may involve or relate to assets, securities or instruments of the issuer (directly, as collateral securing other obligations or otherwise) or persons and entities with relationships with the issuer. The underwriters and their respective affiliates may also make investment recommendations, market color or trading ideas or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long or short positions in such assets, securities and instruments.

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LEGAL MATTERS

The validity of the shares of common stock offered hereby will be passed upon for us by Akin Gump Strauss Hauer & Feld LLP, New York, New York. Certain legal matters in connection with this offering will be passed upon for the underwriters by Latham & Watkins LLP, Houston, Texas.

EXPERTS

Independent registered public accounting firms

The consolidated financial statements of EPE Acquisition, LLC as of December 31, 2012 (successor) and December 31, 2011 (predecessor), the period from February 14, 2012 through December 31, 2012 (successor), the period from January 1, 2012 through May 24, 2012 (predecessor) and each of the two years in the period ended December 31, 2011 (predecessor) appearing in this Prospectus and Registration Statement, have been audited by Ernst & Young LLP, independent registered public accounting firm, as set forth in their report thereon appearing herein. Such consolidated financial statements, except as they relate to Four Star Oil & Gas Company, have been so included in reliance on the report of such independent registered public accounting firm given on the authority of said firm as experts in accounting and auditing.

The audited consolidated financial statements of Four Star Oil & Gas Company as of December 31, 2011 and for the year ended December 31, 2011, not separately presented in this prospectus, have been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, whose report (which contains an emphasis of matter paragraph regarding the company's significant transactions with affiliated companies) thereon appears herein. The audited consolidated financial statements of EPE Acquisition, LLC, to the extent they relate to Four Star Oil & Gas Company, have been so included in reliance on the report of such independent registered public accounting firm given on the authority of said firm as experts in auditing and accounting.

Independent Petroleum Engineering Consultants

Estimates of our oil, NGLs and natural gas reserves, related future net cash flows and the present values thereof as of June 30, 2013 and as of December 31, 2012, included in this prospectus were based in part upon reserve information that was audited by independent petroleum engineering consultants, Ryder Scott Company, L.P. We have included these estimates in reliance on the authority of Ryder Scott Company, L.P. as experts in such matters.

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WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement under the Securities Act, with respect to the shares of our common stock offered by this prospectus. This prospectus, filed as a part of the registration statement, does not contain all of the information set forth in the registration statement or the exhibits and schedules thereto as permitted by the rules and regulations of the SEC. For further information about us and our common stock, you should refer to the registration statement. This prospectus summarizes provisions that we consider material of certain contracts and other documents to which we refer you. You should review the full text of those documents. We have included copies of those documents as exhibits to the registration statement.

The registration statement and the exhibits thereto filed with the SEC may be inspected, without charge, and copies may be obtained at prescribed rates, at the public reference facility maintained by the SEC at 100 F Street, N.E., Washington, D.C. 20549. You may request copies of the documents, upon payment of a duplicating fee, by writing the Public Reference Section of the SEC. Please call 1-800-SEC-0330 for further information on the public reference rooms. Our filings with the SEC are also available to the public from commercial document retrieval services and at the web site maintained by the SEC at http://www.sec.gov.

Our website address is www.epenergy.com. We expect to make available our periodic reports and other information filed with or furnished to the SEC, free of charge through our website, as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

As a result of the offering, we and certain of our stockholders will also become subject to the proxy solicitation rules, annual and periodic reporting requirements and other requirements of the Exchange Act. These periodic reports, proxy statements and other information will be available for inspection and copying at the regional offices, public reference facilities and web site of the SEC referred to above. We will furnish our stockholders with annual reports containing audited financial statements certified by an independent registered public accounting firm and quarterly reports containing unaudited financial statements for the first three quarters of each fiscal year.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this prospectus:

"/d." per day.

"Basin." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"Bbl." One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"Bcf." One billion cubic feet of natural gas.

"Bcfe." One billion cubic feet of natural gas equivalent, determined by using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas.

"Boe." Barrel of oil equivalent, a standard convention used to express oil and gas volumes on a comparable oil equivalent basis. Gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of gas to 1.0 Bbl of oil or NGLs.

"Btu." British Thermal units, a measure of heating value.

"CBM." Coal bed methane.

"Completion." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Developed acreage." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"Development well." A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Drilling locations." Future locations specifically identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves data on contiguous acreage and geologic formations. Unless otherwise indicated in this prospectus, references to drilling locations are gross for operated properties and net for non-operated properties.

"Dry hole." Exploratory or development well that does not produce oil or natural gas in economically producible quantities.

"Estimated ultimate recovery (EUR)." The sum of reserves remaining as of a given date and cumulative production as of that date.

"Exploratory well." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

"Farm-in or farm-out." An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its working interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The working interest received by an assignee is a "farm-in" while the working interest transferred by the assignor is a "farm-out."

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"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differ from nearby rock.

"Gross acreage or gross wells." The total acres or wells, as the case may be, in which a working interest is owned.

"Horizontal drilling." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"MBbl." One thousand barrels of crude oil, condensate or NGLs.

"MBoe." One thousand Boes.

"Mcf." One thousand cubic feet of natural gas.

"Mcfe." One thousand cubic feet equivalent, determined by using a ratio of six Mcf of natural gas to one bbl of crude oil, condensate or NGLs.

"MMBbl." One million barrels of crude oil, condensate or NGLs.

"MMBtu." One million British thermal units.

"MMcfe." One million cubic feet of natural gas equivalent, determined by using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs.

"Net Revenue Interest." The interest in and to all hydrocarbons produced, saved and sold from or allocated to an oil and/or gas property after giving effect to all royalties, overriding royalties, production payments, carried interests, net profits interests, reversionary interests and other burdens upon, measured by or payable out of such hydrocarbon production.

"NGLs." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

"NYMEX." The New York Mercantile Exchange.

"Net acres." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres has 50 net acres.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Proved developed reserves." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Proved reserves." The estimated quantities of oil, natural gas and NGLs which geoscience and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

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"Proved undeveloped ("PUD") reserves." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"Recompletion." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

"Standardized measure." Discounted future net cash inflows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"Tcfe." One trillion cubic feet of natural gas equivalent, determined by using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas.

"Undeveloped acreage." Acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves.

"Unit." The joining of all or substantially all property interests in a particular spacing or development area tract or section, to provide for development and operation of all such separate property interests. Also, the area covered by a unitization agreement or pooling order.

"Wellbore." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"Well cost." The cost of drilling, completing and equipping a well.

"Working interest." The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The following unaudited pro forma condensed consolidated financial data of EP Energy Corporation (the "Company") give effect to the following transactions that are not fully reflected in our historical consolidated successor and predecessor financial statements:

- the completion of this offering (assuming the issuance and sale by the Company of shares of common stock at an offering price of $ per share, which represents the midpoint of the price range set forth on the cover page of this prospectus, generating estimated net proceeds of $ after deducting underwriting discounts and other estimated offering related fees and expenses) and the use of proceeds from this offering as described in "Use of Proceeds,"

- the Corporate Reorganization, as described in "Corporate Reorganization,"

- the following asset divestitures: (i) the sales of our CBM assets in Raton, Arkoma, and the Black Warrior Basin, our South Texas assets, and our Arklatex assets, all of which were completed in the third quarter of 2013, (ii) the sales of our Egypt interests completed in June 2012 and our Gulf of Mexico assets completed in July 2012, and (iii) the announced sale of our Brazilian operations (expected to be completed by the end of the first quarter of 2014), and

- the effects of certain financing transactions and of applying the successful efforts method of accounting for our oil and gas activities, following the initial acquisition of El Paso Corporation's exploration and production assets in May 2012.

The above transactions are reflected in the pro forma financial statements as of and for the six months ended June 30, 2013, and for the year ended December 31, 2012. We are providing pro forma financial data for the years ended December 31, 2011 and December 31, 2010 only to reflect the anticipated divestiture of our Brazil operations, which will be treated as discontinued operations beginning with the third quarter of 2013.

The unaudited pro forma condensed consolidated balance sheet gives effect to all of the transactions above as if they had occurred on June 30, 2013. The unaudited pro forma condensed consolidated income statements (i) for the six months ended June 30, 2013 and year ended December 31, 2012, give effect to all of the transactions above as if they had occurred on January 1, 2012 and (ii) for the years ended December 31, 2011 and 2010, give effect to the anticipated divestiture of our Brazil operations as if it had occurred on January 1, 2010. The unaudited pro forma condensed consolidated financial data should be read together with the audited consolidated financial statements of EPE Acquisition, LLC as of December 31, 2012 (successor) and December 31, 2011 (predecessor) and for the periods from February 14, 2012 (inception) to December 31, 2012 (successor), January 1, 2012 through May 24, 2012 (predecessor), and each of the two years in the period ended December 31, 2011 (predecessor) and the unaudited condensed consolidated financial statements of EPE Acquisition, LLC as of and for the six months ended June 30, 2013, included elsewhere in this prospectus. The pro forma adjustments above are based on currently available information and certain estimates and assumptions. Therefore, the actual effect of the transactions above may differ from the pro forma adjustments included herein. Management believes that the assumptions used to prepare the pro forma adjustments provide a reasonable basis for presenting the effects of such adjustments and the pro forma adjustments give appropriate effect to those assumptions and are properly applied in the unaudited pro forma financial statements.

The unaudited pro forma condensed financial statements and related notes are presented for illustrative purposes only. If the above transactions had occurred in the past, the Company's operating results might have been materially different from those presented in these unaudited pro forma financial statements. The unaudited pro forma financial statements should not be relied upon as an indication of operating results that the Company would have achieved if the above transactions had taken place on the specified date. In addition, future results may vary significantly from those reflected in the unaudited pro forma income statement and should not be relied on as an indication of the future results the Company will have after the completion of the above transactions.

EP ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED BALANCE SHEET

June 30, 2013

(In millions)

	EPE Acquisition, LLC Historical	Divestitures/ Other Adjustments	Corporate Reorganization Adjustments	Initial Public Offering Adjustments	Pro Forma as adjusted
Current assets					
Cash and cash equivalents	$ 283	$ 1,248(a)	$	$	$
		(785)(a)			
		20(b)			
		(500)(c)			
		(200)(c)			
Accounts receivable					
Customer, net of allowance of less than $1	196	(15)(d)			
Other, net of allowance of less than $1	21				
Derivative instruments	77				
Restricted cash	41	(41)(d)			
Assets of discontinued operations	964	(964)(e)			
Other	55	(8)(d)			
Total current assets	1,637	(1,245)			
Property, plant and equipment, net	7,069	(74)			
Other assets					
Investments in unconsolidated affiliates	209				
Unamortized debt issue cost	131	(41)(a)			
		(6)(c)			
Other	135	(10)(d)			
	475	(57)			
Total assets	9,181	(1,376)			
Current liabilities					
Accounts payable					
Trade	$ 128	$			
Other	399	(42)(d)			
Accrued interest	55				
Liabilities of discontinued operations	171	(171)(e)			
Other	100	(48)(d)	31(n)		
Total current liabilities	853	(261)	31		
Long-term debt	5,392	(785)(a)			

			(500)(c)			
Other long-term liabilities		94	(38)(d)	202(n)		
		5,486	(1,584)			
Equity						
Members' equity		2,842	455(e)	(3,050)(m)		
			(200)(c)			
			(47)(a)(c)			
Stockholders' equity				(233)(n)		
				3,050(m)		
Total equity		2,842	208	(233)		
Total liabilities and equity	$	9,181	$ (1,376)	$	$	$

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EP ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

Six Months Ended June 30, 2013

(In millions)

	EPE Acquisition, LLC Historical	Divestitures/ Other Adjustments	Corporate Reorganization Adjustments	Initial Public Offering Adjustments	Pro Forma as adjusted
Operating revenues					
Physical sales	$ 815	$ (44)(d)	$	$	$
Financial derivatives	35				
	850	(44)			
Operating expenses					
Natural gas purchases	10				
Transportation costs	46				
Lease operating expense	98	(20)(d)			
General and administrative	118	(5)(d)		(13)(r)	
Depreciation, depletion and amortization	277	(5)(d)			
Impairments	10	(10)(d)			
Exploration expense	27				
Taxes, other than income taxes	43	(6)(d)			
Total operating expenses	629	(46)		(13)	
Operating income	221	2		13	
Earnings from unconsolidated affiliates	6				
Other expense	(1)	2(d)			
Loss on extinguishment of debt	(3)				
Interest expense	(178)	24(j)			
Income from continuing operations before income taxes	45	28		13	
Income tax expense	2	(2)(d)	23(o)	5	
Income from continuing operations	$ 43	$ 30	$ (23)	$ 8	$
Net income per common share(p):					
Basic					$
Diluted					$
Weighted average common shares outstanding(p):					
Basic					$
Diluted					$

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EP ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

For the Year Ended December 31, 2012

(In millions)

	EPE Acquisition, LLC Historical					
	Successor February 14 (inception), to December 31, 2012	Predecessor January 1 to May 24, 2012	Divestitures/ Other Adjustments	Corporate Reorganization Adjustments	Initial Public Offering Adjustments	Pro Forma as adjusted
Operating revenues						
Physical sales	$ 865	$ 613	$ (264)(d)	$	$	$
Financial derivatives	(62)	365				
Total operating revenues	803	978	(264)			
Operating expenses						
Natural gas purchases	19					
Transportation costs	51	45	(19)(d)			
Lease operating expense	96	96	(80)(d)			
General and administrative	371	75	(24)(d)		(16)(r)	
Depreciation, depletion and amortization	217	319	(138)(d)			
			(190)(f)			
Ceiling test charges		62	(62)(d)			
Impairments	1		(1)(d)			
Exploration expense	50		99(g)			
			(7)(d)			
Taxes, other than income taxes	51	45	(33)(d)			
Total operating expenses	856	642	(455)		(16)	
Operating (loss) income	(53)	336	191		16	
Loss from unconsolidated affiliates	(1)	(5)	6(h)			
Other income (expense)	3	(3)	2(d)			
Loss on extinguishment of debt	(14)					
Interest expense	(219)	(14)	(77)(i)			
			39(j)			
(Loss) income from continuing operations before income taxes	(284)	314	161		16	
Income tax expense	2	136	(138)(k)	62(o)	6	
(Loss) income from continuing operations	$ (286)	$ 178	$ 299	$ (62)	$ 10	$
Net income per common share(p):						
Basic						$
Diluted						$
Weighted average common shares outstanding(p):						
Basic						$

Diluted	$

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EP ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

For the Year Ended December 31, 2011

(In millions)

	EPE Acquisition, LLC Historical Predecessor	Brazil Divestiture(d)	Pro Forma as adjusted
Operating revenues			
Physical sales	$ 1,582	$ (111)	$ 1,471
Financial derivatives	284		284
Other	1	(1)	
Total operating revenues	1,867	(112)	1,755
Operating expenses			
Transportation costs	85		85
Lease operating expense	217	(41)	176
General and administrative	201	(16)	185
Depreciation, depletion and amortization	612	(33)	579
Ceiling test charges	158	(152)	6
Taxes, other than income taxes	91	(15)	76
Total operating expenses	1,364	(257)	1,107
Operating income	503	145	648
Loss from unconsolidated affiliates	(7)		(7)
Other expense	(2)	3	1
Interest expense	(12)		(12)
Income before income taxes	482	148	630
Income tax expense	220	24	244
Net income	$ 262	$ 124	$ 386
Net income per common share(p):			
Basic			$
Diluted			$
Weighted average common shares outstanding(p):			
Basic			$
Diluted			$

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EP ENERGY CORPORATION

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED STATEMENT OF INCOME

For the Year Ended December 31, 2010

(In millions)

	EPE Acquisition, LLC Historical Predecessor	Brazil Divestiture(d)	Pro Forma as adjusted
Operating revenues			
Physical sales	$ 1,380	$ (85)	$ 1,295
Financial derivatives	390		390
Other	19		19
Total operating revenues	1,789	(85)	1,704
Operating expenses			
Transportation costs	73		73
Lease operating expense	193	(37)	156
General and administrative	190	(14)	176
Depreciation, depletion and amortization	477	(29)	448
Ceiling test charges	25		25
Taxes, other than income taxes	85	(12)	73
Other	15		15
Total operating expenses	1,058	(92)	966
Operating income	731	7	738
Loss from unconsolidated affiliates	(7)		(7)
Other income	3	(2)	1
Interest expense	(21)		(21)
Income before income taxes	706	5	711
Income tax expense	263	(4)	259
Net income	$ 443	$ 9	$ 452
Net income per common share(p):			
Basic			$
Diluted			$
Weighted average common shares outstanding(p):			
Basic			$
Diluted			$

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EP ENERGY CORPORATION

NOTES TO UNAUDITED PRO FORMA

CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

The Company made the following adjustments and assumptions in the preparation of the unaudited pro forma condensed consolidated financial statements:

Divestiture and Other Adjustments / Brazil Divestiture

a) Reflects proceeds from the sales of our domestic CBM, South Texas, and Arklatex assets during the third quarter of 2013 and the related use of proceeds to repay $785 million outstanding under our RBL Facility as of June 30, 2013. Debt issue costs written off related to our RBL Facility were $41 million.

b) Reflects anticipated proceeds, net of cash on hand, from the divestiture of our Brazil operations anticipated to occur by the end of the first quarter of 2014.

c) Reflects the repayment of approximately $500 million under our senior secured term loans, the write off of related debt issue costs of $6 million and the payment of a $200 million distribution to our Class A members in August 2013.

d) Reflects the elimination of the carrying value of the assets and liabilities and/or historical income statement effects related to the assets divested or to be divested as noted above to the extent such divestitures were not already reflected in the historical financial statements as discontinued operations.

e) Reflects the removal of assets and liabilities and income from discontinued operations as reflected in the historical financial statements. Reflects the estimated gain on sale of our domestic CBM, South Texas, and Arklatex assets recorded in member's equity based on June 30, 2013 carrying values.

f) Reflects an estimated adjustment to depreciation, depletion and amortization due to the fair value adjustments to our property, plant and equipment as a result of the Acquisition in May 2012, and the application of the successful efforts method of accounting following the Acquisition. Pro forma depreciation, depletion and amortization rates were estimated using amounts based on the purchase price allocation on the acquisition date (May 2012) applied to a depletion rate calculated using estimates of year end 2011 proved reserves held constant throughout the pro forma period and assuming no reserve additions or changes in existing proved reserve categories. The pro forma depreciation, depletion and amortization rates were applied to production volumes by area for the respective periods.

g) Reflects pro forma exploratory dry hole costs, delay rentals, and seismic costs that would have been expensed under the successful efforts method of accounting in periods prior to the Acquisition.

h) Reflects an estimated adjustment to earnings (loss) from unconsolidated affiliates due to the reduction of the amortization of the excess of our investment in Four Star relative to the underlying equity in the net assets resulting from the fair value adjustment to our investment upon the Acquisition in May 2012.

i) Reflects the estimated net adjustment to interest expense, net of capitalized interest, related to $4.25 billion in incremental debt issued in conjunction with the Acquisition in May 2012.

j)

Reflects an interest reduction related to repayment of amounts outstanding under our RBL Facility and term loans in (a) and (c) above.

k) Reflects an adjustment to eliminate income taxes on results of operations to be divested and an adjustment for the Company's change in status from a subchapter C corporation to a limited liability company upon the Acquisition in 2012.

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EP ENERGY CORPORATION

NOTES TO UNAUDITED PRO FORMA

CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

l) Reflects basic and diluted income per common share for the issuance of shares of common stock in the offering.

Corporate Reorganization Adjustments

m) Reflects the reclassification of members' equity to stockholders' equity in conjunction with our Corporate Reorganization.

n) Reflects estimated net deferred tax liabilities for temporary differences between the historical cost basis and tax basis of the Company's assets and liabilities as the result of its change in tax status to a subchapter C corporation from a limited liability company. A corresponding charge to stockholders' equity has been reflected in the unaudited pro forma balance sheet.

o) Reflects the impact on the pro forma income statement of income taxes as though the Company's earnings had been subject to federal income tax.

Initial Public Offering Adjustments

p) Reflects the pro forma net adjustment of $ million to cash and cash equivalents to reflect estimated gross proceeds of approximately $ million from the issuance and sale of shares of common stock at an assumed initial public offering price of $ per share, net of estimated underwriting discounts and commissions of approximately $ million, in the aggregate, and estimated offering expenses of approximately $ million.

q) Reflects the use of net proceeds from the offering (i) to redeem in full the outstanding 8.125%/8.875% Senior PIK Toggle Notes due 2017 issued by our subsidiaries, EPE Holdings LLC and EP Energy Bondco Inc. and pay the redemption premium and the accrued and unpaid interest on those notes, (ii) to repay outstanding borrowings under the RBL Facility, and write-off of approximately $ million of associated debt issuance costs associated with the Senior PIK Toggle Notes and (iii) to pay an approximately $ million fee under the transaction fee agreement with certain affiliates of our Sponsors.

r) Reflects a pro-rata adjustment to reflect the elimination of amounts recorded pursuant to the Management Fee Agreement ($25 million annually) for management, consulting and financial services paid to affiliates of our Sponsors and other investors. The Management Fee Agreement will terminate in conjunction with the offering.

s) Reflects the elimination of interest expense and amortization of debt issuance and related costs in conjunction with repaying Senior PIK Toggle Notes and outstanding borrowings under the RBL Facility with a portion of the net proceeds from the offering.

We have not reflected in the unaudited pro forma income statements (i) $ million fee under the transaction fee agreement with certain affiliates of our Sponsors to be paid upon completion of the offering and (ii) the estimated gain on the sale of our CBM, South Texas, and Arklatex natural gas assets using June 30, 2013 carrying values as such amounts are non-recurring.

The unaudited pro forma condensed consolidated financial statements constitute forward-looking information and are subject to certain risks and uncertainties that could cause actual results to differ materially from those anticipated. See "Risk Factors" and "Cautionary Note Concerning Forward-Looking Statements."

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EPE ACQUISITION, LLC

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(In millions)

(Unaudited)

	Successor		Predecessor
	Six months ended June 30, 2013	February 14 (inception) to June 30, 2012	January 1 to May 24, 2012
Operating revenues			
Oil and condensate	$ 568	$ 74	$ 322
Natural gas	215	46	262
NGL	32	4	29
Financial derivatives	35	57	365
Total operating revenues	850	181	978
Operating expenses			
Natural gas purchases	10	4	
Transportation costs	46	9	45
Lease operating expense	98	15	96
General and administrative	118	208	75
Depreciation, depletion and amortization	277	26	319
Ceiling test charges			62
Impairments	10	1	
Exploration expense	27	6	
Taxes, other than income taxes	43	10	45
Total operating expenses	629	279	642
Operating income (loss)	221	(98)	336
Earnings (loss) from unconsolidated affiliate	6	(1)	(5)
Other (expense) income	(1)	1	(3)
Loss on extinguishment of debt	(3)		
Interest expense	(178)	(53)	(14)
Income (loss) from continuing operations before income taxes	45	(151)	314
Income tax expense	2		136
Income (loss) from continuing operations	43	(151)	178
Income from discontinued operations	44	1	
Net income (loss)	$ 87	$ (150)	$ 178

See accompanying notes.

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EPE ACQUISITION, LLC

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)

(Unaudited)

	Successor		Predecessor
	Six months ended June 30, 2013	February 14 (inception) to June 30, 2012	January 1 to May 24, 2012
Net income (loss)	$ 87	$ (150)	$ 178
Cash flow hedging activities:			
Reclassification adjustment(1)			3
Comprehensive income (loss)	$ 87	$ (150)	$ 181

(1) Reclassification adjustment is stated net of tax. Taxes recognized for the predecessor period from January 1 to May 24, 2012 were $2 million.

See accompanying notes.

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EPE ACQUISITION, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)

(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 283	$ 69
Accounts receivable		
Customer, net of allowance of less than $1 in 2013 and 2012	196	185
Other, net of allowance of $1 for 2013 and 2012	21	15
Materials and supplies	20	16
Derivative instruments	77	108
Restricted cash	41	
Assets of discontinued operations	964	994
Prepaid assets	33	18
Other	2	4
Total current assets	1,637	1,409
Property, plant and equipment, at cost		
Oil and natural gas properties	7,506	6,605
Other property, plant and equipment	66	53
	7,572	6,658
Less accumulated depreciation, depletion and amortization	503	220
Total property, plant and equipment, net	7,069	6,438
Other assets		
Investment in unconsolidated affiliate	209	220
Derivative instruments	116	88
Deferred income taxes	6	6
Unamortized debt issue cost	131	140
Other	13	5
	475	459
Total assets	$ 9,181	$ 8,306

See accompanying notes.

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EPE ACQUISITION, LLC

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)

(Unaudited)

	June 30, 2013	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 128	$ 98
Other	399	347
Derivative instruments	5	17
Accrued taxes other than income	31	21
Accrued interest	55	57
Accrued taxes	1	19
Asset retirement obligations	3	4
Liabilities of discontinued operations	171	156
Other accrued liabilities	60	45
Total current liabilities	853	764
Long-term debt	5,392	4,695
Other long-term liabilities		
Derivative instruments	2	14
Asset retirement obligations	83	76
Other	9	9
Total non-current liabilities	5,486	4,794
Commitments and contingencies (Note 8)		
Members' equity	2,842	2,748
Total liabilities and equity	$ 9,181	$ 8,306

See accompanying notes.

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EPE ACQUISITION, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

(Unaudited)

	Successor		Predecessor
	Six Months ended June 30, 2013	February 14 (Inception) to June 30, 2012	January 1 to May 24, 2012
Cash flows from operating activities			
Net income (loss)	$ 87	$ (150)	$ 178
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities			
Depreciation, depletion and amortization	318	34	319
Deferred income tax expense		1	199
Loss from unconsolidated affiliate, net of cash distributions	11	2	12
Ceiling test charges			62
Impairments	10	1	
Loss on extinguishment of debt	3		
Amortization of equity compensation expense	13	8	
Non-cash portion of exploration expense	24		
Amortization of debt issuance cost	12	3	7
Asset and liability changes			
Accounts receivable	(23)	(18)	132
Accounts payable	61	(6)	(56)
Derivative instruments	(21)	(15)	(201)
Accrued interest	(2)	52	(1)
Other asset changes	(15)	(26)	(7)
Other liability changes	(28)	22	(64)
Net cash provided by (used in) operating activities	450	(92)	580
Cash flows from investing activities			
Capital expenditures	(914)	(150)	(636)
Net proceeds from the sale of assets	10	22	9
Cash paid for acquisitions, net of cash acquired	(2)	(7,126)	(1)
Net cash used in investing activities	(906)	(7,254)	(628)
Cash flows from financing activities			
Proceeds from long-term debt	985	4,323	215
Repayment of long-term debt	(305)	(80)	(1,065)
Contributed member equity		3,300	
Contribution from parent			960
Member distribution	(5)		
Debt issuance costs	(5)	(142)	
Net cash provided by financing activities	670	7,401	110
Change in cash and cash equivalents	214	55	62
Cash and cash equivalents			
Beginning of period	69		25

End of period	$	283	$	55	$	87

See accompanying notes

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EPE ACQUISITION, LLC

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In millions)

(Unaudited)

	Total Members' Equity
Balance at December 31, 2012	$ 2,748
Compensation expense	12
Member distributions	(5)
Net income	87
Balance at June 30, 2013	$ 2,842

See accompanying notes.

EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

EPE Acquisition, LLC (the successor) was formed as a Delaware limited liability company on February 14, 2012 by investment funds affiliated with and managed by Apollo Global Management LLC (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 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 NGL primarily in the United States, with international activities in Brazil. Hereinafter, the acquired entities are referred to as the predecessor for financial accounting and reporting purposes.

These condensed consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (U.S. GAAP) as it applies to interim condensed consolidated financial statements. Because this is an interim period report presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP. You should read this quarterly report along with our 2012 audited consolidated financial statements, which contain a summary of significant accounting policies and other disclosures. The condensed consolidated financial statements as of June 30, 2013, and for each of the successor and predecessor periods presented are unaudited. The consolidated balance sheet as of December 31, 2012 has been derived from the audited consolidated balance sheet included in our 2012 audited consolidated financial statements. In our opinion, all adjustments which are of a normal, recurring nature are reflected to fairly present these interim period results. The results for any interim period are not necessarily indicative of the expected results for the entire year. Our disclosures in this set of financial statements are an update to those provided in our 2012 audited consolidated financial statements.

In June 2013, EP Energy LLC, our wholly-owned subsidiary, entered into three separate agreements to sell its CBM properties located in the Raton, Black Warrior and Arkoma basins; its Arklatex conventional natural gas assets located in East Texas and North Louisiana and its legacy South Texas conventional natural gas assets as further described in Note 2. We have classified the assets and liabilities associated with these assets as discontinued operations in our condensed consolidated balance sheets in all periods presented in this set of financial statements. We have classified the results of operations of the assets held for sale as income (loss) from discontinued operations in successor periods subsequent to the Acquisition (May 25, 2012). For periods prior to the Acquisition, the predecessor applied the full cost method of accounting for oil and natural gas properties where capitalized costs were aggregated by country (e.g., U.S.); accordingly, the assets held for sale did not qualify for, and have not been reflected as discontinued operations in the predecessor financial statement periods. Additionally, the predecessor periods also reflect reclassifications to conform to EPE Acquisition, LLC's financial statement presentation.

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of Presentation and Significant Accounting Policies (Continued)

Significant Accounting Policies

Natural Gas Purchases/Sales. We 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 is 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.

There were no changes in significant accounting policies as described in the 2012 audited consolidated financial statements and no material accounting pronouncements issued but not yet adopted as of June 30, 2013.

2. Acquisitions and Divestitures

Acquisitions. On May 24, 2012, Apollo and other investors acquired all of the equity of our wholly-owned subsidiary, EP Energy Global LLC, for approximately $7.2 billion. The Acquisition was funded with approximately $3.3 billion in equity contributions (which were raised in exchange for the issuance of Class A member units of EPE Acquisition, LLC) and the issuance of approximately $4.25 billion of debt. In conjunction with the Acquisition, a portion of the proceeds was also used to repay approximately $960 million of debt outstanding under the predecessor's revolving credit facility at that time. See Note 7 for an 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 six months ended June 30, 2012 has been derived from the historical, consolidated financial statements and has been prepared as though the

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and Divestitures (Continued)

Acquisition occurred on January 1, 2012. The unaudited pro forma information does not purport to represent what our results of operations would have been if the Acquisition had occurred on such date.

	Six months ended June 30, 2012
	(In millions)
Operating revenues	$ 1,178
Net income	235

Discontinued Operations. In June 2013, EP Energy LLC, our wholly-owned subsidiary entered into three separate agreements to sell its CBM properties located in the Raton, Black Warrior and Arkoma basins; its Arklatex conventional natural gas assets located in East Texas and North Louisiana and its legacy South Texas conventional natural gas assets. In conjunction with signing these agreements in June, we received $41 million in deposits related to these sales, which is recorded as restricted cash and as other accrued liabilities in our consolidated balance sheet. In July and August 2013 we closed these sales for total consideration of approximately $1.3 billion. As a result of entry into these agreements, we presented the assets, liabilities and related income as discontinued operations in all successor periods as described in Note 1.

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

	Successor	
	Six months ended June 30, 2013	February 14 (inception) to June 30, 2012
Operating revenues	$ 168	$ 27
Operating expenses		
Natural gas purchases	16	4
Transportation costs	15	5
Lease operating expense	34	6
Depreciation, depletion and amortization	41	8
Other expense	18	3
Total operating expenses	124	26
Income from discontinued operations	$ 44	$ 1

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and Divestitures (Continued)

	June 30, 2013	December 31, 2012
Assets of discontinued operations		
Current assets	$ 60	$ 55
Property, plant and equipment, net	898	932
Other non-current assets	6	7
Total assets of discontinued operations	$ 964	$ 994
Liabilities of discontinued operations		
Accounts payable	$ 44	$ 40
Other current liabilities	10	5
Asset retirement obligations	116	110
Other non-current liabilities	1	1
Total liabilities of discontinued operations	$ 171	$ 156

Other Divestitures. During the first quarter of 2013, we received approximately $10 million for the sale of domestic oil and natural gas properties. No gain or loss was recorded on this sale. In June 2012, we sold our unevaluated property interests in Egypt for approximately $22 million and did not record a gain or loss on the sale. In addition, the predecessor received approximately $9 million for the sale of domestic oil and natural gas properties that closed in December 2011.

On July 16, 2013, we entered into a Quota Purchase Agreement to sell our Brazil operations which is expected to close by the end of the first quarter of 2014. The sale is subject to Brazilian regulatory approval, as well as certain other customary closing conditions. We recorded a $10 million impairment charge in the second quarter of 2013 based on comparing the fair market value of our Brazil operations to its underlying carrying value. 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. Our Brazil operations will be reflected as discontinued operations in all periods presented beginning with the third quarter of 2013.

3. Ceiling Test Charges

Prior to the Acquisition, the predecessor used the full cost method of accounting. Under this method of accounting, the predecessor conducted quarterly ceiling tests of capitalized costs in each of its full cost pools. During the 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. The charge related to unevaluated costs in that country and included approximately $2 million related to equipment.

4. Income Taxes

Effective Tax Rate. For the six months ended June 30, 2013, the effective tax rate applicable to continuing operations was three percent. This is significantly lower than the statutory rate primarily due to our being a limited liability company treated as a partnership for federal and state income tax purposes. We continue to be subject to foreign income taxes on our Brazil operations.

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Income Taxes (Continued)

Prior to the Acquisition, 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. The effective tax rate for the predecessor period from January 1, 2012 to May 24, 2012, was 43 percent, significantly higher than the statutory rate primarily due to the impact of an Egyptian non-cash charge without a corresponding tax benefit.

5. Financial Instruments

The following table presents the carrying value and fair value of our financial instruments:

	June 30, 2013		December 31, 2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	(In millions)			
Long-term debt	$ 5,392	$ 5,729	$ 4,695	$ 5,039
Derivative instruments	$ 186	$ 186	$ 165	$ 165

As of June 30, 2013 and December 31, 2012, the carrying amounts of cash and cash equivalents, restricted cash, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. We hold long-term debt obligations (see Note 7) with various terms. We estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk related to those 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. In June 2013, we entered into offsetting positions on natural gas derivatives of 35 TBtu on anticipated 2013 production and 42 TBtu on anticipated 2014 production due to an expected decline in natural gas volumes following the sale of natural gas assets as described in Note 2. As of June 30, 2013 and December 31, 2012, we had total derivative contracts related to 33 MMBbl and 34 MMBbl of oil and 174 TBtu and 276 TBtu of natural gas, respectively. None of these contracts are designated as accounting hedges. As of August 13, 2013 we added fixed price oil derivatives on 17 MMBbl.

Interest Rate Derivative Instruments. During July 2012, we entered into interest rate swaps with a notional amount of $600 million that are intended to reduce variable interest rate risk related to our LIBOR based loans. These interest rate derivative instruments started in November 2012 and extend through April 2017. For the six months ended June 30, 2013 we recorded income of $7 million 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 values of our financial instruments into three levels (Levels 1, 2 and 3) based on our

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Financial Instruments (Continued)

assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of June 30, 2013 and December 31, 2012, all of our 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 June 30, 2013 and December 31, 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 certain derivative contracts recorded as assets in the table below we are exposed to the risk that our counterparties may not perform.

	Level 2							
	Derivative Assets				Derivative Liabilities			
			Balance Sheet Location				Balance Sheet Location	
	Gross(1) Fair value	Impact of Netting	Current	Non-current	Gross(1) Fair value	Impact of Netting	Current	Non-current
	(In millions)				(In millions)			
June 30, 2013								
Derivatives	$ 254	$ (61)	$ 77	$ 116	$ (68)	$ 61	$ (5)	$ (2)
December 31, 2012								
Derivatives	$ 235	$ (39)	$ 108	$ 88	$ (70)	$ 39	$ (17)	$ (14)

(1) Gross derivative assets are comprised primarily of $245 million and $231 million of oil and natural gas derivatives and $9 million and $4 million of interest rate derivatives as of June 30, 2013 and December 31, 2012, respectively. Gross derivative liabilities are comprised primarily of $66 million and $64 million of oil and natural gas derivatives and $2 million and $6 million of interest rate derivatives as of June 30, 2013 and December 31, 2012, respectively

The following table presents realized and unrealized net gains and losses on financial oil and 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
	Six Months ended June 30, 2013	February 14 (inception) to June 30, 2012	January 1 to May 24, 2012
Realized and unrealized gains	$ 35	$ 57	$ 365
Accumulated other comprehensive income			5

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Property, Plant and Equipment

Unproved oil and natural gas properties. As of June 30, 2013 and December 31, 2012, we had $1.8 billion and $2.3 billion of unproved oil and natural gas properties on our consolidated balance sheet. The reduction is largely attributable to transferring approximately $0.5 billion from unproved properties to proved properties. For six months ended June 30, 2013, we recorded $23 million of amortization of unproved leasehold costs in exploration expense in our condensed consolidated income statement. Suspended well costs were not material as of June 30, 2013.

Impairments Assessment. Subsequent to the Acquisition, we applied 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. During the second quarter of 2013, we recorded an impairment of approximately $10 million related to our Brazil operations as further described in Note 2. Forward commodity prices can play a significant role in determining impairments. Due to the current forecast of future natural gas prices and considering the significant amount of fair value allocated to our oil and natural gas 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.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement, replacement, or removal 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 our liability, we utilize several assumptions, including a credit-adjusted risk-free rate of 7 percent and a projected inflation rate of 2.5 percent. The net asset retirement liability is reported on our consolidated balance sheet in other current and non-current liabilities. Changes in the net liability from January 1 through June 30, 2013 related to our continuing operations were as follows:

	2013 (In millions)
Net asset retirement liability at January 1	$ 80
Property sales	(1)
Accretion expense	3
Liabilities incurred	6
Changes in estimate	(2)
Net asset retirement liability at June 30(1)	$ 86

(1) Includes approximately $37 million related to our Brazil operations which we entered into a Quota Purchase Agreement to sell (see Note 2).

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. Capitalized interest for the six months ended June 30, 2013 was $8 million. Capitalized interest for the successor period from February 14 (inception) to June 30, 2012 and for the predecessor period from January 1 to May 24, 2012 was $2 million and $4 million, respectively.

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Long-Term Debt

Listed below are our debt obligations:

	Interest Rate	June 30, 2013 (In millions)
EP Energy LLC		
$2.5 billion RBL credit facility due May 24, 2017	Variable	$ 785
$750 million term loan due May 24, 2018(1)(3)	Variable	743
$400 million senior secured term loan due April 30, 2019(2)(3)	Variable	399
$750 million senior secured notes due May 1, 2019(3)	6.875%	750
$2.0 billion senior unsecured notes due May 1, 2020	9.375%	2,000
$350 million senior unsecured notes due September 1, 2022	7.75%	350
EPE Holdings LLC		
$350 million senior PIK toggle note due December 21, 2017(4)	8.125%/8.875%	365
Total		$ 5,392

(1) The term loan was issued at 99 percent of par. In May 2013, we repriced our term loan which reduced the specified margin over LIBOR from 4.00% to 2.75%, and reduced the minimum LIBOR floor from 1.00% to 0.75%. As of June 30, 2013, the effective interest rate of the term loan was 3.50%.

(2) The term loan carries 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) The senior PIK toggle note was issued at 99.50 percent of par at a cash interest rate of 8.125% and PIK interest rate of 8.875%. We may elect to pay interest in cash by increasing the principal amount by issuing new notes for the entire amount of the interest payment or by paying interest on half of the principal amount of the notes in cash and half in interest. During the quarter ended June 30, 2013, we elected to increase the principal amount of the notes by $8 million related to interest owed on the notes.

During the six months ended June 30, 2013, we amortized $11 million of deferred financing costs. During the period from February 14 (inception) to June 30, 2012, we amortized $3 million of deferred financing costs. During the predecessor period from January 1 to May 24, 2012, we amortized $7 million of deferred financing costs. These costs are included in interest expense. As of June 30, 2013, we had $131 million remaining of unamortized debt issue costs. During the six months ended June 30, 2013, we recorded a $3 million loss on extinguishment of debt in our consolidated income statement for the portion of deferred financing costs written off in conjuction with our $750 million term loan repricing in May 2013 and the first semi-annual redetermination of our RBL in March 2013.

$2.5 Billion Reserve-based Loan (RBL). In March 2013, we completed our first semi-annual redetermination increasing the borrowing base of our RBL Facility from $1.8 billion to $2.5 billion. Under this facility, we can borrow funds or issue letters of credit (LCs). During the six months ended

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Long-Term Debt (Continued)

June 30, 2013, we borrowed $680 million. As of June 30, 2013, we had $785 million of outstanding borrowings and approximately $9 million of letters of credit issued, leaving $1.71 billion of remaining capacity available under the facility. As of August 13, 2013, we had no outstanding borrowings under the facility.

The RBL Facility is collateralized by certain of our oil and natural gas properties and as noted has a borrowing base subject to semi-annual redetermination if there is a downward revision or a reduction of our oil and natural gas reserves due to future declines in commodity prices, performance revisions, sales of assets or otherwise, if certain other additional debt is incurred. A reduction in our borrowing base could negatively impact our ability to borrow funds under the RBL Facility in the future. On June 7, 2013, we received consents from the lenders and entered into an agreement that provides that the current borrowing base remain in effect, notwithstanding the consummation of potential asset dispositions until the earlier of (i) 30 days after providing a June 30, 2013 reserve report or (ii) September 1, 2013.

Guarantees. Our obligations under the RBL, term loan, secured and unsecured notes are fully and unconditionally guaranteed, jointly and severally, by the present and future direct and indirect wholly-owned material domestic subsidiaries of our subsidiary, EP Energy LLC. Our foreign wholly-owned subsidiaries are not guarantors. As of June 30, 2013, foreign subsidiaries that do not guarantee the unsecured notes held approximately 1% of our consolidated assets and had no outstanding indebtedness, excluding intercompany obligations. For the six months ended June 30, 2013, and for the period from February 14 (inception) to June 30, 2012, these non-guarantor subsidiaries generated between 3% and 8% of our revenue including the impacts of financial derivative instruments.

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. There have been no significant changes to our restrictive covenants, and as of June 30, 2013, we were in compliance with all of our debt covenants. For a further discussion of our credit facilities and restrictive covenants, see our 2012 audited consolidated financial statements.

8. Commitments and Contingencies

Legal Proceedings and Other Contingencies

We and our subsidiaries and affiliates are named defendants in numerous legal proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various stages of adoption, review and/or implementation. 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 these 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. 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 June 30, 2013, we had approximately $2 million accrued for all outstanding legal proceedings and other contingent matters.

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Commitments and Contingencies (Continued)

Brazil Labor Claim. In Brazil, one of our subsidiaries as well as a formerly affiliated party have been named in a lawsuit by a former contractor of the former affiliated party claiming entitlement to certain employee benefits under Brazilian law. In May 2013, an evidentiary hearing was held in this matter before the administrative judge of the 42nd Labor Court of the State of Rio de Janeiro and on July 19, 2013, a first-level decision was issued finding some liability for a social contribution to the government and that labor benefits are owed to the former contractor only for the period from August 1, 2009 to July 31, 2010. Based on our current analysis of factors surrounding this claim and the above referenced decision, we believe our exposure to this claim, if any, will not be material to our financial statements.

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 is filed in Louisiana state court in New Orleans and the amount of damages is unspecified. Our subsidiary, EP Energy Management, L.L.C., is one of the named defendants as successor to Colorado Oil Company, Inc. and Gas Producing Enterprises as operators of five to seven wells from the mid-1960s 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.

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 the quarter ended June 30, 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 air, land and water quality. 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 June 30, 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 is estimated to 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.

Climate Change and other Emissions. The EPA and several state environmental agencies have adopted regulations to regulate greenhouse gas (GHG) emissions. Although the EPA has adopted a

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Commitments and Contingencies (Continued)

"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 regulating 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. In August 2010, the EPA finalized a rule that mandates emission reductions of hazardous air pollutants from reciprocating internal combustion engines that requires us to install emission controls on engines across our operations. Certain amendments to this rule were finalized in January 2013. Engines subject to the regulations must comply by October 2013. We currently estimate to incur capital expenditures in 2013 to complete the required modifications and testing of less than $1 million.

In August 2012, the EPA finalized New Source Performance Standard regulations to reduce various air pollutants from the oil and natural gas industry. These regulations will limit emissions from the hydraulic fracturing of certain natural gas wells and equipment including compressors, storage vessels and natural gas processing plants. The EPA has recently proposed amendments to this rule, in part phasing in emission controls for storage vessels past current deadlines. We do not anticipate a material impact associated with compliance to these new requirements.

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 anticipate we will incur capital expenditures totaling $2 million in 2013 and 2014 related to the installation of tank emission controls.

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 the 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 have received notice that we could be designated, or have been asked for information to determine whether we could be designated as a Potentially Responsible Party (PRP) with respect to the Casmalia Remediation site located in California under the CERCLA or state equivalents. As of June 30, 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 in some

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EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Commitments and Contingencies (Continued)

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 environmental reserve 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.

9. Long-Term Incentive Compensation

Our long-term incentive (LTI) programs currently include a cash-based incentive program and certain equity based programs established in conjunction with the Acquisition including Class A "matching units," and management incentive units. In April 2013, we granted additional cash-based LTI awards with a fair value of $21 million on the grant date that are being amortized on an accelerated basis over a three-year vesting period. Each of these awards are further described in our 2012 audited consolidated financial statements.

Compensation expense (recorded as general and administrative expense on our income statement) related to all of our long-term incentive awards was approximately $24 million during the six months ended June 30, 2013 and approximately $11 million for the period from February 14 (inception) to June 30, 2012. As of June 30, 2013, we had unrecognized compensation expense of $56 million related to our cash based long-term incentive awards, Class A "matching units," and management incentive units. We will recognize an additional $16 million related to our outstanding awards during the rest of 2013 and the remainder over the requisite service periods.

10. Investment in Unconsolidated Affiliate

Our investment in Four Star Oil & Gas Company (Four Star), an unconsolidated affiliate, is accounted for using the equity method of accounting. Our condensed consolidated income statement reflects (i) our share of net earnings directly attributable to Four Star, and (ii) the amortization of the excess of the carrying value of our investment relative to the underlying equity in the net assets of the entity. As of June 30, 2013 and December 31, 2012, our investment in Four Star was $209 million and $220 million, respectively. Included in these amounts was approximately $119 million and $125 million, respectively, related to the excess of the carrying value of our investment in Four Star relative to the underlying equity in its net assets.

EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Investment in Unconsolidated Affiliate (Continued)

Below is summarized financial information of the operating results of our unconsolidated affiliate (in millions).

	Successor		Predecessor
	Six Months ended June 30, 2013	February 14 (inception) to June 30, 2012	January 1 to May 24, 2012
		(In millions)	
Operating revenues	$ 102	$ 8	$ 75
Operating expenses	67	12	58
Net income (loss)	22	(2)	11

We amortize the excess of our investment in Four Star 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 which are predominantly natural gas reserves. Amortization of our investment for the successor periods related to the six months ended June 30, 2013 and the period from February 14 (inception) to June 30, 2012 was $6 million and $1 million, respectively. Amortization of our investment for the predecessor period from January 1 to May 24, 2012 was $12 million. Changes in natural gas prices impact the fair value of our investment in Four Star, and sustained declines in natural gas prices could cause the fair value of our investment to decline which could require us to record an impairment of the carrying value of our investment in the future if that loss is determined to be other than temporary.

For the six months ended June 30, 2013 and the predecessor period from January 1, 2012 to May 24, 2012, we received dividends from Four Star of approximately $17 million and $8 million, respectively. We did not receive dividends from Four Star for the successor period from February 14, 2012 (inception) to June 30, 2012.

11. Related Party Transactions

Members' Distribution. In August 2013, we made a leveraged distribution of approximately $200 million to our Sponsors.

Management Fee Agreement. We are subject to a management fee agreement with certain of our Sponsors for the provision of certain management consulting and advisory services which terminates on the twelve-year anniversary of the Acquisition date (May 24, 2012) if not terminated earlier by mutual agreement of the parties, or upon a change in control or a specified initial public offering transaction. Under the agreement, we pay a non-refundable annual management fee of $25 million. We recorded management fees within general and administrative expense for the six months ended June 30, 2013 of approximately $13 million and for the period from February 14 (inception) to June 30, 2012 of approximately $2 million.

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 June 30, 2013, we recorded approximately $59 million as capital expenditures for amounts provided under this agreement.

EPE ACQUISITION, LLC

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Related Party Transactions (Continued)

Related Party Transactions Prior to the Acquisition. 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 NGL production. Additionally, 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. Prior to the Acquisition, El Paso also (i) 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 (ii) filed consolidated U.S. federal and certain state tax returns which included the predecessor's taxable income and (iii) matched short-term cash surpluses and needs of its participating affiliates to minimize total borrowing from outside sources through its cash management program.. All agreements ceased on the date of the Acquisition. The following table shows revenues and charges to/from affiliates for the following predecessor period:

	January 1 to May 24, 2012
	(In millions)
Operating revenues	$ 143
Operating expenses	44

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Report of Independent Registered Public Accounting Firm

The Audit Committee of the Board of Managers of
EPE Acquisition, LLC

We have audited the accompanying consolidated financial statements of EPE Acquisition, LLC (and subsidiaries), which comprise the consolidated balance sheets as of December 31, 2012 (Successor) and December 31, 2011 (Predecessor), and the related consolidated statements of income, comprehensive income, changes in equity, and cash flows for the period from February 14, 2012 to December 31, 2012 (Successor), the period from January 1, 2012 to May 24, 2012 (Predecessor), and each of the two years in the period 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. We did not audit the consolidated financial statements of Four Star Oil & Gas Company (a corporation in which the Company has an 49% interest), which statements reflect approximately $70 million in investments in unconsolidated affiliates from Four Star Oil & Gas Company as of December 31, 2011 (Predecessor), and approximately $29 million in earnings from unconsolidated affiliates for the year ended December 31, 2011 (Predecessor), from Four Star Oil & Gas Company. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Four Star Oil & Gas Company, is based solely on the report of the other auditors.

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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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 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 the other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of EPE Acquisition, LLC at December 31, 2012 (Successor) and December 31, 2011 (Predecessor), and the consolidated results of its operations and its cash flows for the period from February 14, 2012 to December 31, 2012 (Successor), the period from January 1, 2012 to May 24, 2012 (Predecessor), and for each of the two years in the period ended December 31, 2011 (Predecessor) in conformity with U.S. generally accepted accounting principles.

/s/ Ernst & Young LLP

Houston, Texas

June 28, 2013

Except for Notes 1 and 2, as to which that date is

August 14, 2013

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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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EPE ACQUISITION, LLC

CONSOLIDATED STATEMENTS OF INCOME

(In millions)

	Successor February 14 (inception) to December 31, 2012	Predecessor January 1 to May 24, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Operating revenues				
Oil and condensate	$ 555	$ 322	$ 552	$ 346
Natural gas	278	262	973	974
NGL	32	29	57	60
Financial derivatives	(62)	365	284	390
Other			1	19
Total operating revenues	803	978	1,867	1,789
Operating expenses				
Natural gas purchases	19			
Transportation costs	51	45	85	73
Lease operating expense	96	96	217	193
General and administrative	371	75	201	190
Depreciation, depletion and amortization	217	319	612	477
Ceiling test charges		62	158	25
Impairments	1			
Exploration expense	50			
Taxes, other than income taxes	51	45	91	85
Other				15
Total operating expenses	856	642	1,364	1,058
Operating (loss) income	(53)	336	503	731
Loss from unconsolidated affiliate	(1)	(5)	(7)	(7)
Other income (expense)	3	(3)	(2)	3
Loss on extinguishment of debt	(14)			
Interest expense				
Third party	(219)	(14)	(9)	(16)
Affiliated			(3)	(5)
(Loss) income from continuing operations before income taxes	(284)	314	482	706
Income tax expense	2	136	220	263
(Loss) income from continuing operations	(286)	178	262	443
Income from discontinued operations	30			
Net (loss) income	$ (256)	$ 178	$ 262	$ 443

See accompanying notes.

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EPE ACQUISITION, LLC

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(In millions)

	Successor	Predecessor		
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Net (loss) income	$ (256)	$ 178	$ 262	$ 443
Cash flow hedging activities:				
Reclassification adjustment(1)		3	7	7
Comprehensive (loss) income	$ (256)	$ 181	$ 269	$ 450

(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 years ended December 31, 2011 and 2010 are $2 million, $4 million and $4 million, respectively.

See accompanying notes.

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EPE ACQUISITION, LLC

CONSOLIDATED BALANCE SHEETS

(In millions)

	Successor December 31, 2012	Predecessor December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 69	$ 25
Accounts receivable		
Customer, net of allowance of less than $1 in 2012 and 2011	185	135
Affiliates		132
Other, net of allowance of $1 for 2012 and $7 for 2011	15	39
Materials and supplies	16	28
Derivatives	108	272
Assets of discontinued operations	994	
Prepaid assets	18	12
Other	4	15
Total current assets	1,409	658
Property, plant and equipment, at cost		
Oil and natural gas properties, of which $481 was excluded from amortization for 2011	6,605	21,923
Other property, plant and equipment	53	147
	6,658	22,070
Less accumulated depreciation, depletion and amortization	220	18,003
Total property, plant and equipment, net	6,438	4,067
Other assets		
Investment in unconsolidated affiliate	220	346
Derivatives	88	9
Deferred income taxes	6	7
Unamortized debt issue cost	140	8
Other	5	4
	459	374
Total assets	$ 8,306	$ 5,099

See accompanying notes.

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EPE ACQUISITION, LLC

CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)

	Successor December 31, 2012	Predecessor December 31, 2011
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 98	$ 140
Affiliates		47
Other	347	258
Derivatives	17	7
Accrued taxes other than income	21	33
Accrued interest	57	
Deferred income taxes		91
Accrued taxes	19	
Asset retirement obligations	4	5
Liabilities of discontinued operations	156	
Other accrued liabilities	45	8
Total current liabilities	764	589
Long-term debt	4,695	851
Other long-term liabilities		
Derivatives	14	73
Asset retirement obligations	76	148
Deferred income taxes		291
Other	9	47
Total non-current liabilities	4,794	1,410
Commitments and contingencies (Note 8)		
Members'/Stockholder's equity		
Common stock, par value $1 per share; 1,000 shares authorized and outstanding at December 31, 2011		
Additional paid-in capital		4,580
Accumulated deficit		(1,476)
Accumulated other comprehensive loss		(4)
Members' equity	2,748	
Total members'/stockholder's equity	2,748	3,100
Total liabilities and equity	$ 8,306	$ 5,099

See accompanying notes.

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EPE ACQUISITION, LLC

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

	Successor	Predecessor		
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Year Ended December 31, 2011	Year Ended December 31, 2010
Cash flows from operating activities				
Net (loss) income	$ (256)	$ 178	$ 262	$ 443
Adjustments to reconcile net (loss) income to net cash provided by operating activities				
Depreciation, depletion and amortization	268	319	612	477
Deferred income tax expense	1	199	304	320
Loss from unconsolidated affiliates, net of cash distributions	15	12	53	57
Impairments/Ceiling test charges	1	62	158	25
Loss on extinguishment of debt	14			
Amortization of equity compensation expense	17			
Non-cash portion of exploration expense	23			
Amortization of debt issuance cost	13	7	3	5
Other non-cash income items			1	
Asset and liability changes				
Accounts receivable	(73)	132	(20)	(17)
Accounts payable	66	(56)	(67)	90
Affiliate income taxes		4	83	(172)
Derivatives	281	(201)	47	(99)
Accrued interest	57	(1)	(1)	1
Other asset changes	(18)	(3)	12	16
Other liability changes	40	(72)	(21)	(79)
Net cash provided by operating activities	449	580	1,426	1,067
Cash flows from investing activities				
Capital expenditures	(877)	(636)	(1,591)	(1,238)
Net proceeds from the sale of assets	110	9	612	155
Cash paid for acquisitions, net of cash acquired	(7,126)	(1)	(22)	(51)
Increase in note receivable with parent			(236)	
Other				4
Net cash used in investing activities	(7,893)	(628)	(1,237)	(1,130)
Cash flows from financing activities				
Proceeds from long-term debt	5,825	215	2,030	500
Repayment of long-term debt	(1,139)	(1,065)	(1,480)	(1,034)
Contributed member equity	3,323			
Contribution from parent		960		
Distributions to members	(337)			
Change in note payable with parent			(781)	489
Debt issuance costs	(159)		(7)	(1)
Net cash provided by (used in) financing activities	7,513	110	(238)	(46)
Change in cash and cash equivalents	69	62	(49)	(109)
Cash and cash equivalents				
Beginning of period		25	74	183
End of period	$ 69	$ 87	$ 25	$ 74

Supplemental cash flow information				
Interest paid, net of amounts capitalized	$ 145	$ 7	$ 9	$ 7
Income tax (refunds) payments	2	2	(158)	105

See accompanying notes.

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EPE ACQUISITION, LLC

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(In millions)

	Shares	Common Stock	Additional Paid-in Capital	Retained Earnings (Accumulated deficit)	Accumulated Other Comprehensive Income	Total Stockholder's / Members' Equity
Predecessor						
Balance at January 1, 2010	1.000	$	$ 4,725	$ (2,178)	$ (18)	$ 2,529
Contribution from parent			91			91
Other				(3)	7	4
Net income				443		443
Balance at December 31, 2010	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 (inception)						$
Member contributions						3,324
Member distributions						(337)
Equity compensation expense						17
Net loss						(256)
Balance at December 31, 2012						$ 2,748

See accompanying notes.

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation, Significant Accounting Policies and Subsequent Events

Basis of Presentation and Consolidation

EPE Acquisition, LLC (the successor) was formed as a Delaware limited liability company on February 14, 2012 by investment funds affiliated with and managed by Apollo Global Management LLC (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, 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 EPE Acquisition, LLC'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. We use the cost method of accounting where we are unable to exert significant influence over the 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 estimates are based on contract data, commodity prices and preliminary throughput and allocation measurements.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of Presentation, Significant Accounting Policies and Subsequent Events (Continued)

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. We present these purchases and sales transactions on a gross basis in the successor period. As of December 31, 2012, we had one customer that accounted for 10 percent or more of our total revenues. The predecessor period in 2012 had three customers, and for the years ended December 31, 2011 and 2010, 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 NGL 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, 2012 and 2011, 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 collectibility 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.

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of Presentation, Significant Accounting Policies and Subsequent Events (Continued)

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 natural gas and crude oil.

Full Cost (Predecessor). Prior to the Acquisition, the predecessor used the full cost method to account for their oil and natural gas properties. Under the full cost method, substantially all costs incurred in connection with the acquisition, development and exploration of oil and natural gas reserves were capitalized on a country-by-country basis. These capitalized amounts included the costs of unproved properties, 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.

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

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of Presentation, Significant Accounting Policies and Subsequent Events (Continued)

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 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. Cost is recognized in our consolidated financial statements as general and administrative expense over the requisite service period, net of estimated forfeitures. See Note 9.

Environmental Costs and Other Contingencies

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

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

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of Presentation, Significant Accounting Policies and Subsequent Events (Continued)

Other Contingencies. We recognize liabilities for 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.

Our derivatives are reflected on our consolidated 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 enter into derivative contracts for the purpose of economically hedging the price of our anticipated oil and natural gas production even though we do not designate the derivatives as hedges for accounting purposes. We classify cash flows related to derivative contracts based on the nature and purpose of the derivative. As the derivative cash flows are considered an integral part of our oil and natural gas operations, they are classified as cash flows from operating activities. In our consolidated balance sheet, receivables and payables resulting from the settlement of our derivative instruments are reported as trade receivables and payables. See Note 5 for a further discussion of our derivatives.

Income Taxes

We are a limited liability company, treated as a partnership for federal and state income tax purposes, with income tax liabilities and/or benefits passed through to our members. Our subsidiary, EP Energy LLC is, however subject to the Texas margin tax and pays any liability directly to the state of Texas. The aggregate difference in the basis of net assets for financial and tax reporting purposes cannot be readily determined as we do not have access to information about each member's tax attributes.

Our Brazil operations are corporate entities for Brazil purposes. For Brazil, we record current income taxes based on our current taxable income and provide for deferred income taxes to reflect estimated future tax payments and receipts. We also record deferred tax assets and liabilities, which 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 in Brazil under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available.

The realization of our deferred tax assets related to our Brazilian operations depends on recognition of sufficient future taxable income in Brazil during periods in which those temporary differences are deductible. We reduce deferred tax assets by a valuation allowance when, based on our

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Basis of Presentation, Significant Accounting Policies and Subsequent Events (Continued)

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 prior carryback years, 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 refunded for their portion of these income taxes. In certain states, the predecessor filed and paid taxes directly to the state taxing authorities.

Subsequent Events

In June 2013, EP Energy LLC, our wholly-owned subsidiary, entered into three separate agreements to sell its CBM properties located in the Raton, Black Warrior and Arkoma basins; its Arklatex conventional natural gas assets located in East Texas and North Louisiana and its legacy South Texas conventional natural gas assets as further described in Note 2. Additionally, we entered into offsetting positions on natural gas derivatives of 35 TBtu on anticipated 2013 production and 42 TBtu on anticipated 2014 production due to an expected decline in natural gas volumes following the sale of these natural gas assets.

On July 16, 2013, we entered into a Quota Purchase Agreement to sell our Brazil operations which is expected to close by the end of the first quarter of 2014. The sale is subject to Brazilian regulatory approval, as well as certain other customary closing conditions.

In August 2013, we made a leveraged distribution of approximately $200 million to our Sponsors.

2. Acquisitions and Divestitures

Acquisitions. On May 24, 2012, Apollo and other investors acquired all of the equity of our wholly owned subsidiary, EP Energy Global LLC for approximately $7.2 billion. The Acquisition was funded with approximately $3.3 billion in equity contributions (which were raised in exchange for the issuance of Class A member units of EPE Acquisition, LLC) and the issuance of approximately $4.25 billion of debt. In conjunction with the sale, a portion of the proceeds were also used to repay approximately $960 million outstanding under EP Energy Global LLC's revolving credit facility at that time. See Note 7 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 presented as of December 31, 2012, reflects our purchase price allocation based on available information to

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Acquisitions and Divestitures (Continued)

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 year ended December 31, 2012, has been derived from the 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	$	1,925	$	1,867
Net income		143		454

Divestitures. In 2012, our divestitures primarily related to the sale of our Egypt interests for approximately $22 million and the sale of oil and natural gas properties located in the Gulf of Mexico for a gross purchase price of approximately $103 million. Proceeds from the Gulf of Mexico sale net of purchase price adjustments were 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 oil and natural gas properties located in the Eagle Ford, Southern and Central divisions in several transactions from which they received proceeds that totaled approximately $612 million. During 2010, the predecessor sold processing plants and related gathering systems for cash proceeds of approximately $126 million. The predecessor did not record a gain or loss on any of these sales.

Discontinued Operations. In June 2013, we entered into three separate agreements to sell certain of our domestic natural gas assets, including CBM properties located in the Raton, Arkoma, and the Black Warrior basins; natural gas properties in South Texas; and the majority of our Arklatex natural gas properties. In July and August 2013 we closed these sales for total consideration of approximately $1.3 billion. As a result of entry into these agreements, we have classified the assets and liabilities associated with these assets as discontinued operations in our consolidated balance sheet as of December 31, 2012. We have classified the results of operations of the assets held for sale as income (loss) from discontinued operations in the successor period subsequent to the Acquisition (May 25, 2012). For periods prior to the Acquisition, the predecessor applied the full cost method of accounting

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Acquisitions and Divestitures (Continued)

for oil and natural gas properties where capitalized costs were aggregated by country (e.g. U.S.); accordingly, the assets held for sale did not qualify for, and have not been reflected as discontinued operations in the predecessor financial statement periods. We have also updated financial information and certain related disclosures in these consolidated financial statements for the successor period from inception (February 14, 2012) to December 31, 2012 to reflect the presentation of assets sold in July and August of 2013 as discontinued operations.

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

	Successor February 14 (inception) to December 31, 2012
Operating revenues	$ 187
Operating expenses	
Natural gas purchases	24
Transportation costs	22
Lease operating expense	40
Depreciation, depletion and amortization	51
Other expense	20
Total operating expenses	157
Income from discontinued operations	$ 30

	December 31, 2012
Assets of discontinued operations	
Current assets	$ 55
Property, plant and equipment, net	932
Other non-current assets	7
Total assets of discontinued operations	$ 994
Liabilities of discontinued operations	
Accounts payable	$ 40
Other current liabilities	5
Asset retirement obligations	110
Other non-current liabilities	1
Total liabilities of discontinued operations	$ 156

Other. 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 consolidated balance sheet. The remaining $173 million in fees were reflected in general and administrative expense in our consolidated income statement. Additionally, during 2012 we recorded approximately $48 million related to transition and

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Acquisitions and Divestitures (Continued)

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 consolidated income statement.

3. Ceiling Test Charges

Under the full cost method of accounting, the predecessor recorded ceiling test charges of capitalized costs in each of the U.S. and Brazil full cost pools as well as a non-cash charge of unevaluated costs related to Egypt as noted in the table below.

	January 1 to May 24, 2012	Predecessor Year Ended December 31, 2011	Year Ended December 31, 2010
		(In millions)	
U.S.	$	$ 6	$
Brazil		152	
Egypt	62		25
Total	$ 62	$ 158	$ 25

During the first quarter of 2012, the predecessor recorded a non-cash charge of approximately $62 million as a result of the decision to exit exploration activities in Egypt. The charge related to unevaluated costs in that country and included approximately $2 million related to equipment. Forward commodity prices can play a significant role in determining impairments. Due to the current forecast of future natural gas prices and considering the significant amount of fair value allocated to our natural gas and oil properties in conjunction with the Acquisition, sustained lower natural gas and oil prices from present levels could result in an impairment of the carrying value of our proved properties in the future. For the predecessor period ended December 31, 2011, ceiling test charges of approximately $152 million related to Brazil oil and natural gas operations were recorded and an impairment of certain oil field related materials and supplies of $6 million was recorded.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Income Taxes

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

	Successor	Predecessor		
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011	Year ended December 31, 2010
			(In millions)	
Pretax (Loss) Income				
U.S.	$ (300)	$ 387	$ 635	$ 736
Foreign	16	(73)	(153)	(30)
	$ (284)	$ 314	$ 482	$ 706
Components of Income Tax Expense (Benefit)				
Current				
Federal	$	$ (61)	$ (77)	$ (71)
State		(3)	1	3
Foreign	1	1	(8)	11
	1	(63)	(84)	(57)
Deferred				
Federal		188	284	314
State		11	19	12
Foreign	1		1	(6)
	1	199	304	320
Total income tax expense	$ 2	$ 136	$ 220	$ 263

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Income Taxes (Continued)

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	
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Year ended December 31, 2011	Year ended December 31, 2010
			(In millions, except rates)	
Income taxes at the statutory federal rate of 35%	$ (89)	$ 110	$ 169	$ 247
Increase (decrease)				
State income taxes, net of federal income tax effect		5	12	10
Partnership earnings not subject to tax	89			
Earnings from unconsolidated affiliates where we received or will receive dividends		(2)	(8)	(9)
Valuation allowances			23	6
Foreign income (loss) taxed at different rates	2	27	24	9
Other		(4)		
Income tax expense (benefit)	$ 2	$ 136	$ 220	$ 263
Effective tax rate	1%	43%	46%	37%

The effective tax rate for the successor period from February 14 (inception) to December 31, 2012 was significantly lower than the statutory rate as we are a limited liability company, treated as a partnership for federal and state income tax purposes, with income tax liabilities and/or benefits passed through to our members. 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 the impact of the Brazilian ceiling test charge without a corresponding U.S. or Brazilian tax benefit (deferred tax benefits related to the Brazilian ceiling test charge were offset by an equal valuation allowance) offset by 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.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Income Taxes (Continued)

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

	Successor December 31, 2012	Predecessor December 31, 2011
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$	$ (495)
Investments in unconsolidated affiliates		(67)
Derivatives		(73)
Other	(5)	
Total deferred tax liabilities	(5)	(635)
Deferred tax assets		
Net operating loss and tax credit carryovers	116	458
Property, plant and equipment	167	112
Other		3
Valuation allowance	(272)	(313)
Total deferred tax assets	11	260
Net deferred tax assets (liabilities)	$ 6	$ (375)

As a partnership, for U.S. federal and state income tax purposes, we do not recognize differences between the underlying tax and book basis of our assets and liabilities as deferred taxes. Thus, the deferred balances in the table above relate solely to Brazil. In conjunction with the Acquisition, U.S. deferred taxes of the predecessor were settled with El Paso through a non-cash contribution.

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 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. In Brazil, we continue to have a number of years in which our Brazilian returns are subject to review. The following table shows the balance of unrecognized tax benefits and changes therein:

	Successor February 14, 2012 (inception) to December 31. 2012	Predecessor Year ended December 31. 2011
	(In millions)	
Amount at beginning of period	$	$ 30
Amount at Acquisition date	7	
Foreign currency fluctuations	(1)	(1)
Settlements with taxing authorities		(1)
Amount at December 31	$ 6	$ 28

As of December 31, 2012 unrecognized tax benefits and any associated interest and penalties would not affect our recorded income tax expense or our effective income tax rate if recognized in

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Income Taxes (Continued)

future periods since our 2012 deferred tax assets as of December 31, 2012 are fully offset by a valuation allowance. Unrecognized tax benefits for the predecessor were transferred to KMI as part of the Acquisition.

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 2012, nor do we have any accrued interest and penalties on our consolidated balance sheet as of December 31, 2012. As of December 31, 2011, the predecessor had $2 million of accrued interest and penalties on the consolidated balance sheet, and recognized $7 million in interest and penalties related to unrecognized tax benefits.

Net Operating Loss and Tax Credit Carryovers. As of December 31, 2012 we have foreign net operating loss carryovers of $258 million and capital loss carryovers of $82 million. The losses related to Brazil are carried over indefinitely and can be utilized to offset up to 30 percent of Brazilian taxable income annually. As of December 31, 2011, the predecessor had $816 million of federal net operating loss and $340 million of state net operating loss that were transferred to KMI as part of the Acquisition.

Valuation Allowances. As of December 31, 2012, our valuation allowance relates to deferred tax assets recorded on foreign net operating losses and temporary differences. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of existing valuation allowances. Changes to the valuation allowance are shown in the table below:

	Successor February 14, 2012 (inception) to December 31. 2012	Predecessor Year ended December 31. 2011
	(In millions)	
Amount at beginning of period	$	$ 291
Amount at Acquisition date(1)	323	
Temporary differences for local differences, impairments, depreciation, depletion and amortization and foreign currency translation	(19)	28
Net operating losses	(2)	(6)
Transfer on sale of Egypt	(30)	
Amount at December 31	$ 272	$ 313

(1) Includes a fair value adjustment at Acquisition date of $10 million.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Financial Instruments

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

	Successor December 31, 2012		Predecessor December 31. 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-term debt	$ 4,695	$ 5,039	$ 851	$ 765
Derivatives	$ 165	$ 165	$ 201	$ 201

For the year ended December 31, 2012 and 2011, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. We hold long term debt obligations (see Note 7) with various terms. We estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk related to these instruments.

Oil and Natural Gas Derivatives. 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, 2012 and 2011, 34,232 MBbl and 14,530 MBbl of oil and 276 TBtu and 105 TBtu of natural gas, respectively, are hedged through derivatives. None of these contracts are designated as accounting hedges. Subsequent to December 31, 2012 and as of June 28, 2013, we added fixed price oil derivatives of 5,623 MBbl and fixed price natural gas derivatives of 59 TBtu, and we added oil basis swaps of 9,320 MBbl related to a portion of our crude differential exposure. In addition, in June 2013 we unwound fixed price natural gas derivatives of 35 TBtu on anticipated 2013 production and 38 TBtu on anticipated 2014 production due to an expected decline in natural gas volumes pursuant to entering into purchase and sale agreements on certain natural gas assets as further described in Note 2.

Interest Rate Derivatives. During July 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 derivatives started in November 2012 and extend through April 2017. As of December 31, 2012, we have a $2 million net liability related to interest rate derivatives listed in our consolidated balance sheet. For the period of February 14, 2012 (inception) to December 31, 2012 we recorded an increase of $3 million in interest expense related to our interest rate derivatives.

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 values of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. Each of the levels are described below:

Level 1 instruments' fair values are based on quoted prices in actively traded markets.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Financial Instruments (Continued)

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, 2012 and 2011, 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 of derivative financial instruments at December 31, 2012 and 2011. Derivative assets and liabilities are netted with counterparties where we have a legal right of offset and derivatives are classified as either current or non-current assets or liabilities based on their anticipated settlement date. On certain derivative contracts recorded as assets in the table below we are exposed to the risk that our counterparties may not perform or post the required collateral.

	Level 2	
	Successor December 31. 2012	Predecessor December 31. 2011
	(In millions)	
Assets		
Oil and natural gas derivatives	$ 231	$ 304
Interest rate derivatives	4	
Impact of master netting arrangements	(39)	(23)
Total net assets	196	281
Liabilities		
Oil and natural gas derivatives	(64)	(103)
Interest rate derivatives	(6)	
Impact of master netting arrangements	39	23
Total net liabilities	(31)	(80)
Total	$ 165	$ 201

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Financial Instruments (Continued)

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

	Successor	Predecessor		
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	Years ended December 31, 2011	2010
Realized and unrealized (losses) gains	$ (62)	$ 365	$ 284	$ 390
Accumulated other comprehensive income		5	11	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 NGL 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) requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our assets from derivatives at December 31, 2012 represent derivative instruments from nine counterparties; all of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of A- or better) credit rating. We enter into derivatives directly with third parties and are not currently required to post collateral or other security for credit risk. Subject to the terms of our $2 billion RBL credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the RBL credit facility.

6. Property, Plant and Equipment

Unproved Oil and Natural Gas Properties (Successor). As of the Acquisition date and December 31, 2012, we had $3.0 billion and $2.3 billion, respectively, of unproved oil and natural gas properties on our consolidated balance sheet primarily a result of the allocation of the purchase price in conjunction with the Acquisition. The reduction is largely attributable to transferring approximately $0.7 billion from unproved properties to proved properties. In addition, we recorded $23 million of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of December 31, 2012.

Unevaluated Capitalized Costs (Predecessor). As of December 31, 2011 unevaluated capitalized costs related to oil and natural gas properties were $399 million in the U.S. and $82 million in Egypt and Brazil. The predecessor excluded capitalized costs of oil and natural gas properties from amortization that were in various stages of evaluation or were part of a major development project.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Property, Plant and Equipment (Continued)

Presented below is an analysis of the capitalized costs of oil and natural gas properties by year of expenditure that were not being amortized as of December 31, 2011 pending determination of proved reserves (in millions):

	Cumulative Balance December 31, 2011	Costs Excluded for Years Ended December 31(1) 2011	Costs Excluded for Years Ended December 31(1) 2010	Cumulative Balance January 1, 2010
U.S.				
Acquisition	$ 301	$ 20	$ 206	$ 75
Exploration	98	80	4	14
Total U.S.(2)	399	100	210	89
Egypt & Brazil				
Acquisition	36	1		35
Exploration	46	8	20	18
Total Egypt & Brazil(3)	82	9	20	53
Worldwide	$ 481	$ 109	$ 230	$ 142

(1) Included capitalized interest of $2 million and $6 million for the years ended December 31, 2011 and 2010.

(2) Included $155 million related to the Wolfcamp Shale and $94 million related to the Eagle Ford Shale at December 31, 2011.

(3) Included $8 million related to Brazil at December 31, 2011.

Asset Retirement Obligations. We have legal obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We have obligations to plug wells when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue a liability on those legal obligations when we can estimate the timing and amount of their settlement and include obligations where we will be legally required to replace, remove or retire the associated assets.

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 estimate 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

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Property, Plant and Equipment (Continued)

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:

	Successor February 14 (inception) to December 31. 2012	Predecessor January 1 to December 31. 2011
	(In millions)	
Net asset retirement liability at beginning of period	$	$ 135
Fair value of asset retirement liability at Acquisition date(1)	136	
Liabilities settled	(2)	(16)
Property sale(2)	(64)	(9)
Accretion expense	4	13
Liabilities incurred	6	3
Changes in estimate		27
Net asset retirement liability at December 31	$ 80	$ 153

(1) Includes a fair value adjustment at Acquisition date of approximately $34 million.

(2) For the successor period, property sales relate to the sale of properties in the Gulf of Mexico.

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 period from February 14, 2012 (inception) to December 31, 2012 was $12 million. Capitalized interest for the predecessor periods from January 1, 2012 to May 24, 2012, the years ended December 31, 2011 and 2010 was $4 million, $13 million and $9 million, respectively.

7. Long Term Debt

In conjunction with the Acquisition, we issued or obtained approximately $4.25 billion of debt and repaid EP Energy Global LLC's amounts outstanding with an equity contribution from its then existing parent El Paso. During 2012, EP Energy LLC also re-priced its $750 million term loan at an effective interest rate of 5.0% from 6.5%, issued an additional $350 million of senior unsecured notes, and obtained an additional $400 million through a senior secured term loan. Proceeds were primarily used to paydown amounts outstanding under our RBL credit facility. In December 2012, EPE Holdings LLC (our subsidiary) issued $350 million in senior PIK (pay in kind) toggle notes and used the net proceeds primarily for distributions. We may elect to pay interest on the notes in cash, by increasing the principal amount of the notes by issuing new notes for the entire amount of the interest payment or by paying interest on half of the principal amount of the notes in cash and half in interest. Interest on the notes is payable on December 15 and June 15 of each year. As of December 31, 2012 and as of March 31, 2013 we elected to increase the principal amount of the notes by $1 million and $8 million, respectively, related to interest owed on the notes.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Long Term Debt (Continued)

Listed below are additional details related to each of our debt obligations and their book values as of the periods presented:

	Interest Rate	Successor December 31, 2012	Predecessor December 31, 2011
		(In millions)	
EP Energy LLC			
$1 billion revolving credit facility due June 2, 2016	Variable	$	$ 850
Senior notes due June 1, 2013	7.75%		1
$2 billion RBL credit facility due May 24, 2017	Variable	105	
$750 million term loan due April 24, 2018(1)(3)	Variable	742	
$400 million senior secured term loan due April 30, 2019(2)(3)	Variable	399	
$750 million senior secured note due May 1, 2019(3)	6.875%	750	
$2.0 billion senior unsecured note due May 1, 2020	9.375%	2,000	
$350 million senior unsecured note due September 1, 2022	7.75%	350	
EPE Holdings LLC			
$350 million senior PIK toggle note due December 21, 2017(4)	8.125%/8.875%	349	
Total		$ 4,695	$ 851

(1) The term loan was issued at 99 percent of par and carries a specified margin over the LIBOR of 4.00%, with a minimum LIBOR floor of 1.00%. As of December 31, 2012 the effective interest rate of the note was 5.00%. In May 2013, we entered into an agreement to reprice our term loan which will carry 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 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) The senior PIK toggle note was issued at 99.50 percent of par at a cash interest rate of 8.125% and PIK interest rate of 8.875%.

As of December 31, 2012 we have $140 million in deferred financing costs on our consolidated balance sheet as a result of these financings. During 2012 we recorded amortization of $13 million of deferred financing costs included in interest expense in our consolidated income statement. We also 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.

$2.0 Billion Reserve-based Loan (RBL). We have a $2.0 billion credit facility in place which allows us to borrow funds or issue letters of credit (LCs). This credit facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to redetermination semi-annually beginning in April 2013. A downward revision of oil and natural gas reserves due to future declines in commodity prices, performance revisions or otherwise, could require a redetermination of the

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Long Term Debt (Continued)

borrowing base and could negatively impact our ability to borrow funds from such facilities in the future. The borrowing base is also impacted if certain other additional debt is incurred. As of December 31, 2012, under the credit facility we had a $1.8 billion RBL borrowing base, $1.7 billion of remaining capacity, $105 million of outstanding borrowings, and approximately $9 million of letters of credit issued. In March 2013, we completed our first semi-annual redetermination increasing the borrowing base of our RBL to $2.5 billion. On June 7, 2013, EP Energy LLC received consents from the lenders under its RBL facility and entered into an agreement to provide that the current borrowing base will remain in effect notwithstanding the consummation of potential asset dispositions until the earlier of (i) 30 days after providing a June 30, 2013 reserve report or (ii) September 1, 2013. As of June 28, 2013, we had $785 million of outstanding borrowings under the RBL Facility. Listed below is a further description of the RBL credit facility as of December 31, 2012:

Credit Facility	Maturity Date	Interest Rate	Commitment fees
$2.0 billion RBL	May 24, 2017	LIBOR + 1.50%(1) 1.50% for LCs	0.375% commitment fee on unused capacity

(1) Based on the December 31, 2012 borrowing level. Amounts outstanding under the $2.0 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.

Guarantees. Our obligations under the RBL, term loan, secured and unsecured notes are fully and unconditionally guaranteed, jointly and severally, by the present and future direct and indirect wholly-owned material domestic subsidiaries of our subsidiary, EP Energy LLC. Our foreign wholly-owned subsidiaries are not parties to the guarantees. As of December 31, 2012, foreign subsidiaries that will not guarantee the notes held approximately 2% of consolidated assets and had no outstanding indebtedness, excluding intercompany obligations. For the period from February 14, 2012 (inception) to December 31, 2012, non-guarantor subsidiaries generated approximately 7% of our revenue including the impacts of financial derivatives.

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 5.0 to 1.0 during the current period. Certain other covenants and restrictions, among other things, also limit our and our subsidiaries' 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, 2012, we and our subsidiaries were in compliance with debt covenants.

8. Commitments and Contingencies

Legal Proceedings and Other Contingencies

We and our subsidiaries and affiliates are named defendants in numerous legal proceedings that arise in the ordinary course of our business. There are also other regulatory rules and orders in various

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Commitments and Contingencies (Continued)

stages of adoption, review and/or implementation. 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. We disclose matters that are reasonably possible of negative outcome and material to our financial statements. 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. 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, 2012, we had approximately $20 million accrued for all outstanding legal proceedings and other contingent matters, including a reserve related to an audit of sales and use taxes in the State of Texas.

Brazil Labor Claim. In Brazil, one of EP Energy LLC's subsidiaries as well as a formerly affiliated party have been named in a lawsuit by a former contractor of the former affiliated party claiming entitlement to certain employee benefits under Brazilian law. The case is currently pending before the 42nd Labor Court of the State of Rio de Janeiro. We are currently unable to estimate a range of reasonably possible loss, if any, primarily due to the novelty of the legal claims being presented.

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. We are indemnified by KMI if and to the extent the ultimate outcome exceeds our reserves. During 2012 we settled one of our Texas sales and use tax audits for $3 million, including fees. We are currently contesting the remaining assessment and the ultimate outcome is still uncertain. We believe amounts reserved are adequate.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental air, land and water quality. 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, 2012, 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.

Climate Change and other Emissions. The EPA and several state environmental agencies have adopted regulations to regulate greenhouse gas (GHG) emissions. Although the EPA has adopted a

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Commitments and Contingencies (Continued)

"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 regulating 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. In August 2010, the EPA finalized a rule that impacts emissions of hazardous air pollutants from reciprocating internal combustion engines and requires us to install emission controls on engines across our operations. Engines subject to the regulations have to be in compliance by October 2013. We currently estimate we will incur capital expenditures in 2013 to complete the required modifications and testing of less than $1 million.

In August 2012, the EPA finalized New Source Performance Standard regulations to reduce various air pollutants from the oil and natural gas industry. These regulations will limit emissions from the hydraulic fracturing of certain natural gas wells and equipment including compressors, storage vessels and natural gas processing plants. We do not anticipate a material impact associated with compliance to these new requirements.

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 anticipate the installation of tank emission controls that will require approximately $3 million capital expenditures starting in 2013 and extending through 2014.

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 the 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 have received notice that we could be designated, or have been asked for information to determine whether we could be designated as a Potentially Responsible Party (PRP) with respect to the Casmalia Remediation site located in California under the CERCLA or state equivalents. As of December 31, 2012, 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 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

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Commitments and Contingencies (Continued)

strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these matters are included in the environmental reserve 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.

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 until 2017. Future minimum annual rental commitments under non-cancelable future operating lease commitments at December 31, 2012, were as follows:

Year Ending December 31,	**Operating Leases**
	(In millions)
2013	$ 14
2014	13
2015	14
2016	13
2017	8
Total	$ 62

Rental expense for the period from February 14, 2012 (inception) to December 31, 2012 was $10 million.

Other Commercial Commitments

At December 31, 2012, we have various commercial commitments totaling $1,074 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 $161 million in 2013, $134 million in 2014, $108 million in 2015, $114 million in 2016, $104 million in 2017 and $453 million thereafter.

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

EP Energy LLC 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:

Cash-Based Long Term Incentive. In addition to annual bonus payments, we provide a long term cash-based incentive program 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 managers, and individual performance for the year. Cash-based LTI awards are expected to be granted annually and 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). For accounting purposes, these performance based cash incentive awards have been treated as liability awards with a fair value on the grant date of approximately $23 million. For the period from February 14, 2012 (inception) to December 31, 2012, we recorded approximately $8 million in expense related to these awards. As of December 31, 2012, we had unrecognized compensation expense of $12 million related to these awards of which approximately $8 million will be recognized in 2013 and the remainder on an accelerated basis over the remaining requisite service period. During April 2013 we granted additional cash-based LTI awards with a fair value of $21 million on the grant date that will be amortized on an accelerated basis over a three-year vesting period.

Long Term Equity Incentive Awards. We provide certain individuals with two forms of long term equity incentive awards as follows:

Class A "Matching" Grants. In conjunction with the Acquisition, our employees purchased a total of approximately 24,000 Class A units (at a purchase price of $1,000 per Class A unit). 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 (approximately 12,000 units) and (ii) a "guaranteed cash bonus" which was paid in March 2013 equivalent to the amount of the "matching" Class A unit grant. Matching units are subject to repurchase by the company in the event of certain termination scenarios. For accounting purposes, we treated the "guaranteed cash bonus" amounts as liability awards that would be settled in cash and 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 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 will 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 period from February 14, 2012 (inception) to December 31, 2012, we recognized approximately $11 million related to both of these awards. As of December 31, 2012, we had unrecognized compensation expense of $13 million related to both of these awards, of which we will recognize $6 million in 2013 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 approximately 808,000 Management Incentive Units ("MIPs"). These MIPs are intended to constitute profits interests. Each award of MIPs

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 are scheduled to 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 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 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 period from February 14, 2012 (inception) to December 31, 2012, we recognized approximately $15 million related to these awards. As of December 31, 2012, we had unrecognized compensation expense of $59 million. Of this amount, $40 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.

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. As of December 31, 2012, we had contributed $7 million of matching contributions.

Equity Awards Outstanding Prior to Acquisition. Prior to the merger between KMI and El Paso, certain of our employees held vested and unvested stock options, restricted shares and performance shares granted under El Paso's equity plan. Pursuant to the terms of the merger agreement between El Paso and KMI, each outstanding El Paso stock option, restricted share and performance share automatically vested upon completion of the merger. In the case of outstanding performance shares, performance was deemed to be attained at target. On the merger date, each outstanding stock option, restricted share and performance share was converted into the right to receive either cash or a mixture of cash and shares of KMI common stock for all shares subject to such awards (in the case of stock options, less the aggregate exercise price), pursuant to the terms of the El Paso/KMI merger agreement. Each holder also received warrants as part of the merger consideration in respect of such equity awards. Through the merger date, the predecessor recorded as general and administrative expense in the consolidated income statements, amounts billed directly by El Paso for compensation expense related to these stock-based compensation awards granted directly to its employees, as well as its proportionate share of El Paso's corporate compensation expense. However, 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 consolidated financial statements.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Investment in Unconsolidated Affiliate

Our investment in Four Star Oil & Gas Company (Four Star), an unconsolidated affiliate, is accounted for using the equity method of accounting. Our consolidated income statement reflects (i) our share of net earnings directly attributable to the unconsolidated affiliate, and (ii) other adjustments, such as the amortization of the excess of the carrying value of our investment relative to the underlying equity in the net assets of the entity. As of December 31, 2012 and December 31, 2011, our total investment in unconsolidated affiliate was $220 million and $346 million ($281 million net of related deferred income taxes). Included in these amounts was approximately $125 million and $272 million ($207 million net of related deferred income taxes) related to the excess of the carrying value of our investment in Four Star relative to the underlying equity in its net assets.

Below is summarized financial information of the operating results and financial position of our unconsolidated affiliate.

	Successor	Predecessor		
	February 14 (inception) to December 31, 2012	January 1 to May 24, 2012	2011	2010
	(In millions)	(In millions)		
Operating results				
Operating revenues	$ 105	$ 75	$ 257	$ 249
Operating expenses	87	58	167	151
Net income	11	11	60	63

	Successor As of December 31, 2012	Predecessor As of December 31, 2011
	(In millions)	
Financial position data		
Current assets	$ 64	$ 77
Non-current assets	241	290
Current liabilities	51	64
Non-current liabilities	133	148
Equity in net assets	121	155

We hold an approximate 49 percent ownership investment in Four Star. In conjunction with the Acquisition and purchase price allocation, we adjusted our basis in Four Star to approximately $235 million.

We amortize the excess of our investment in Four Star 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 which are predominantly natural gas reserves. Amortization of our investment for the successor period from February 14, 2012 (inception) to December 31, 2012 was $7 million. Amortization for the predecessor period from January 1, 2012 to May 24, 2012 and for the years ended December 31, 2011 and 2010 was $12 million, $34 million and $38 million, respectively. Based on changes in the outlook for natural gas prices, the fair value of our investment in Four Star could decline which may require us to record an impairment of the carrying value of our investment in the future if that loss is determined to be other than temporary.

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EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Investment in Unconsolidated Affiliate (Continued)

We received dividends from Four Star for the period from February 14, 2012 (inception) to December 31, 2012 of approximately $13 million. For the predecessor periods from January 1, 2012 to May 24, 2012 and years ended December 31, 2011 and 2010, we received dividends of $8 million, $46 million and $50 million.

11. Related Party Transactions

Transaction Fee Agreement. In connection with the Acquisition, we were subject to a transaction fee agreement with certain of our Sponsors (the "Service Providers") for the provision of certain structuring, financial, investment banking and other similar advisory services. At the time of the Acquisition, we paid one-time transaction fees of $71.5 million (recorded as general and administrative expense in our consolidated income statement) to the Service Providers in the aggregate in exchange for services rendered in connection with structuring, arranging the financing and performing other services. In the event of any future transactions (including any merger, consolidation, recapitalization or sale of assets or equity interests resulting in a change of control of the equity and voting securities, or sale of all or substantially all of the assets or which is in connection with one or more public offerings, each as further defined in the Transaction Fee Agreement), we would pay an additional transaction fee equal to the lesser of (i) 1% of the aggregate enterprise value paid or provided and (ii) $100 million.

Management Fee Agreement. We entered into a management fee agreement with certain of our Sponsors for the provision of certain management consulting and advisory services which terminates on the twelve-year anniversary of the Acquisition date (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 agreement, we pay a non-refundable annual management fee of $25 million. For the period from February 14, 2012 (inception) to December 31, 2012, we recognized approximately $16 million in general and administrative expense related to management fees.

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, 2012, we recorded approximately $21 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 NGL production.

Other than continuing transition services agreements with KMI, 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

EPE ACQUISITION, LLC

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Related Party Transactions (Continued)

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.

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. Substantially all of the affiliated accounts receivable at December 31, 2011 related to sales of natural gas to El Paso Marketing. 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. At December 31, 2011, contractual deposits were $8 million associated with El Paso's regulated interstate pipelines. The following table shows revenues and charges to/from affiliates for the following predecessor periods:

	Predecessor		
	January 1, 2012 to May 24, 2012	Years ended December 31, 2011	2010
Operating revenues	$ 143	$ 634	$ 746
Operating expenses	44	138	132
Reimbursements of operating expenses		3	2

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.

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.

	Predecessor		Successor		
	Quarters Ended(1)				
		June 30			
2012	**March 31**	**April 1 to May 24**	**April 1 to June 30**	**September 30**	**December 31**
Operating revenues	$ 484	$ 494	$ 181	$ 172	$ 450
Operating income (loss)	62	274	(98)	(102)	147
Net income (loss)	15	163	(150)	(196)	90

	Predecessor			
2011	**March 31**	**June 30**	**September 30**	**December 31**
Operating revenues	$ 250	$ 535	$ 653	$ 429
Operating (loss) income	(30)	250	190	93
Net income (loss)	(18)	170	61	49

(1) There were no operations for the successor period from February 14 to March 30, 2012.

Below are significant items affecting comparability of amounts reported in the respective periods of 2012 and 2011:

December 31, 2012. We recorded $62 million of gains related to changes in fair value of our derivatives.

September 30, 2012. We recorded $181 million of losses related to changes in fair value of our derivatives.

June 30, 2012. For the successor period from April 1 to June 30 we recorded $57 million of gains related to changes in the fair value of our derivatives and $173 million of transaction costs related to the Acquisition. For the predecessor period from April 1 to May 24, we recorded $289 million or gains related to changes in the fair value of our derivatives.

March 31, 2012. We recorded $76 million of gains related to changes in the fair value of our derivatives and a $62 million non-cash charge related to the predecessor's unevaluated costs in Egypt.

December 31, 2011. We recorded $10 million of gains related to changes in fair value of our derivatives.

September 30, 2011. We recorded $251 million of gains related to changes in fair value of our derivatives and a $152 million non-cash Brazilian ceiling test charge.

June 30, 2011. We recorded $132 million of gains related to changes in the fair value of our derivatives.

March 31, 2011. We recorded $109 million of losses related to changes in the fair value of our derivatives.

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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 NGL, in the United States (U.S.) and Brazil.

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.	Brazil and Egypt(1)	Worldwide
2012 Consolidated(2):			
Oil and natural gas properties	$ 7,441	$ 92	$ 7,533
Less accumulated depreciation, depletion and amortization	249	6	255
Net capitalized costs	$ 7,192	$ 86	$ 7,278
2012 Unconsolidated Affiliate Four Star(3):			
Oil and natural gas properties	$ 627	$	$ 627
Less accumulated depreciation, depletion and amortization	510		510
Net capitalized costs	$ 117	$	$ 117
2011 Consolidated:			
Oil and natural gas properties:			
Costs subject to amortization	$ 20,156	$ 1,284	$ 21,440
Costs not subject to amortization	399	82	481
	20,555	1,366	21,921
Less accumulated depreciation, depletion and amortization	16,837	1,087	17,924
Net capitalized costs	$ 3,718	$ 279	$ 3,997
2011 Unconsolidated Affiliate Four Star(3):			
Oil and natural gas properties	$ 628	$	$ 628
Less accumulated depreciation, depletion and amortization	489		489
Net capitalized costs	$ 139	$	$ 139

(1) Capitalized costs for Egypt were $74 million as of December 31, 2011, included in costs not subject to amortization. We sold our interests in Egypt in June 2012. During 2012 we recorded a non-cash charge of $62 million related to our unevaluated properties in Egypt. During 2011 we recorded a ceiling test charge of $152 million in our Brazilian full cost pool.

(2) In conjunction with the Acquisition, we began applying the successful efforts method of accounting for oil and natural gas exploration and development activities.

(3) Amounts represent our approximate 49 percent equity interest in the underlying oil and gas assets of Four Star. Four Star applies the successful efforts method of accounting for its oil and gas properties.

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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 period from February 14, 2012 (inception) to December 31, 2012 and the predecessor periods from January 1, 2012 to May 24, 2012 and the years ended December 31, 2011 and 2010 (in millions):

	U.S.	Brazil and Egypt(1)	Worldwide
Successor			
Consolidated from February 14, 2012 (inception) to December 31, 2012:			
Property acquisition costs			
Proved properties	$	$	$
Unproved properties	20		20
Exploration costs (capitalized and expensed)	120	6	126
Development costs	787	3	790
Costs expended	927	9	936
Asset retirement obligation costs	28	3	31
Total costs incurred	$ 955	$ 12	$ 967
Unconsolidated Affiliate from February 14, 2012 (inception) 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	3	82
Development costs	503		503
Costs expended	613	3	616
Asset retirement obligation costs	21	10	31
Total costs incurred	$ 634	$ 13	$ 647
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	858	15	873
Development costs	694	12	706
Costs expended	1,597	27	1,624
Asset retirement obligation costs	25		25
Total costs incurred	$ 1,622	$ 27	$ 1,649
2011 Unconsolidated Affiliate:			
Development costs expended	$ 12	$	$ 12
2010 Consolidated:			
Property acquisition costs			
Proved properties	$ 51	$	$ 51
Unproved properties	269		269
Exploration costs	600	58	658
Development costs	276	28	304
Costs expended	1,196	86	1,282

Asset retirement obligation costs	7		7
Total costs incurred	$ 1,203	$ 86	$ 1,289
2010 Unconsolidated Affiliate:			
Development costs expended	$ 20	$	$ 20

(1) Costs incurred for Egypt were less than $1 million for the successor period from February 14, 2012 (inception) to December 31, 2012 and $2 million, $8 million and $20 million for the predecessor periods from January 1, 2012 to May 24, 2012 and the years ended December 31, 2011 and 2010. 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.

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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 $25 million for the period from February 14, 2012 (inception) to December 31, 2012, and capitalized interest of $12 million for the same period.

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 each of the years ended December 31, 2011 and 2010. The predecessor also capitalized interest of $4 million, $13 million and $9 million for the period from January 1, 2012 to May 24, 2012 and the years ended December 31, 2011 and 2010, respectively.

During 2011 the predecessor was informed that its environmental permit request for the Pinauna Field in the Camamu Basin was denied. As a result, $94 million of unevaluated capitalized costs related to this field were released into the Brazilian full cost pool. Additionally, during 2011, approximately $86 million of unevaluated capitalized costs were released into the Brazilian full cost pool related to the Espirito Santo Basin upon completion of the evaluation of exploratory wells drilled in 2009 and 2010 without any additions to proved reserves.

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, 2012 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 2012 consolidated proved reserves were consistent with estimates of proved reserves filed with other federal agencies in 2012 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 prepared by us as of December 31, 2012. In connection with its audit, Ryder Scott reviewed 81% (by value) of the total proved reserves on a natural gas equivalent basis representing 90% of the total discounted future net cash flows of these proved reserves. Ryder Scott also conducted an audit of the estimates we prepared of the proved reserves of Four Star as of December 31, 2012. In connection with the audit of these proved reserves, Ryder Scott reviewed 85% of the properties associated with Four Star's total proved reserves on a natural gas equivalent basis, representing 92% of the total discounted future net cash flows. For the reviewed properties, 97% of our total proved undeveloped

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reserves were evaluated and our overall proved reserves estimates are within 10% of Ryder Scott's estimates.

	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes (in Bcfe)
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	
Consolidated:								
January 1, 2010	2,052	105	2,157	60,849	4,196	65,045	304	2,549
Revisions due to prices	108	3	111	8,719	88	8,807	105	164
Revisions other than price	(58)	(13)	(71)	7,873	(1,246)	6,627	6,977	11
Extensions and discoveries(1)	506		506	28,141		28,141	3,088	693
Purchases of reserves in place	25		25	3,045		3,045		43
Sales of reserves in place	(21)		(21)	(1,024)		(1,024)		(27)
Production	(216)	(10)	(226)	(4,363)	(384)	(4,747)	(1,423)	(263)
December 31, 2010	2,396	85	2,481	103,240	2,654	105,894	9,051	3,170
Revisions due to prices	(9)		(9)	713	3	716		(5)
Revisions other than price	44	6	50	(1,630)	(34)	(1,664)	(1,124)	34
Extensions and discoveries(2)	519		519	90,128		90,128	7,525	1,105
Purchases of reserves in place				13		13		
Sales of reserves in place	(153)		(153)	(8,983)		(8,983)	(139)	(207)
Production	(231)	(10)	(241)	(5,680)	(354)	(6,034)	(1,068)	(284)
December 31, 2011	2,566	81	2,647	177,801	2,269	180,070	14,245	3,813
Revisions due to prices	(718)		(718)	(604)	1	(603)	(371)	(724)
Revisions other than price	55	(3)	52	(18,451)	288	(18,163)	10,267	5
Extensions and discoveries(3)	119		119	109,125		109,125	13,450	854
Purchases of reserves in place				3		3	2	
Sales of reserves in place	(72)		(72)	(2,501)		(2,501)	(1,358)	(95)
Production	(223)	(10)	(233)	(9,131)	(406)	(9,537)	(1,904)	(302)
December 31, 2012	1,727	68	1,795	256,242	2,152	258,394	34,331	3,551

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	Natural Gas (in Bcf)			Oil and Condensate (in MBbls)			NGL (in MBbls)	Equivalent Volumes (in Bcfe)
	U.S.	Brazil	Worldwide	U.S.	Brazil	Worldwide	U.S.	
Unconsolidated Affiliate Four Star:								
January 1, 2010	158		158	1,907		1,907	5,264	201
Revisions due to prices	8		8	44		44	87	9
Revisions other than price	6		6	36		36	(325)	4
Extensions and discoveries							5	
Production	(17)		(17)	(364)		(364)	(573)	(22)
December 31, 2010	155		155	1,623		1,623	4,458	192
Revisions due to prices	(5)		(5)	31		31	(28)	(5)
Revisions other than price	2		2	221		221	1,034	9
Extensions and discoveries								
Production	(17)		(17)	(306)		(306)	(556)	(22)
December 31, 2011	135		135	1,569		1,569	4,908	174
Revisions due to prices	(13)		(13)	(37)		(37)	(310)	(15)
Revisions other than price	19		19	803		803	1,710	35
Extensions and discoveries	25		25	95		95	137	26
Production	(16)		(16)	(282)		(282)	(478)	(21)
December 31, 2012	150		150	2,148		2,148	5,967	199
Total Combined:								
December 31, 2010	2,551	85	2,636	104,863	2,654	107,517	13,509	3,362
December 31, 2011	2,701	81	2,782	179,370	2,269	181,639	19,153	3,987
December 31, 2012	1,877	68	1,945	258,390	2,152	260,542	40,298	3,750
Consolidated:								
Proved developed reserves:								
January 1, 2012	1,488	81	1,569	46,797	2,269	49,066	5,168	1,895
December 31, 2012	1,189	68	1,257	55,924	2,152	58,076	9,080	1,660
Proved undeveloped reserves:								
January 1, 2012	1,078		1,078	131,004		131,004	9,077	1,918
December 31, 2012	538		538	200,318		200,318	25,251	1,891
Unconsolidated Affiliate Four Star:								
Proved developed reserves:								
January 1, 2012	116		116	1,520		1,520	4,066	150
December 31, 2012	140		140	2,111		2,111	5,289	185
Proved undeveloped reserves:								
January 1, 2012	19		19	49		49	842	24
December 31, 2012	10		10	37		37	678	14
Total Combined:								
Proved developed reserves:								

January 1, 2012	1,604	81	1,685	48,317	2,269	50,586	9,234	2,045
December 31, 2012	1,329	68	1,397	58,035	2,152	60,187	14,369	1,845
Proved undeveloped reserves:								
January 1, 2012	1,097		1,097	131,053		131,053	9,919	1,942
December 31, 2012	548		548	200,355		200,355	25,929	1,905

(1) In 2010, of the 693 Bcfe of extensions and discoveries, 452 Bcfe related to the Central division, of which, 425 Bcfe related to the Haynesville Shale area. There were 238 Bcfe of extensions and discoveries in the Gulf Coast division with 187 Bcfe of that coming from the Eagle Ford Shale. The Western division accounted for 3 Bcfe of extensions and discoveries and there were no extensions and discoveries in the International division.

(2) In 2011, of the 1,105 Bcfe of extensions and discoveries, 428 Bcfe related to the Central division, of which, 389 Bcfe related to the Haynesville Shale area. There were 592 Bcfe of extensions and discoveries in the Southern division with 479 Bcfe of that coming from the Eagle Ford Shale and 113 Bcfe coming from the Wolfcamp Shale. The Western division accounted for 85 Bcfe of extensions and discoveries and there were no extensions and discoveries in the International division.

(3) In 2012, of the 880 Bcfe of combined extensions and discoveries, 50 Bcfe related to the Central division, of which, 37 Bcfe related to the Altamont area. There were 664 Bcfe of extensions and discoveries in the Eagle Ford Shale. There were 141 Bcfe of extensions and discoveries coming from the Wolfcamp Shale. There were no extensions and discoveries in the

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International division. Of the 880 Bcfe of extensions and discoveries, 737 Bcfe were liquids representing 84% of EP Energy's total extensions and discoveries which is a 26% increase in liquid extensions and discoveries from the previous year.

In accordance with SEC Regulation S-X, Rule 4-10 as amended, we use the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within 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, 2012 was $2.76 per MMBtu for natural gas and $94.61 per barrel of oil. The prices used for our International assets were contractually defined. The aggregate International price used to estimate our proved reserves at December 31, 2012 was $7.53 per MMBtu for natural gas and $111.21 per barrel of oil.

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, 2012, 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, 2012. The current 12-month average natural gas prices used to determine our domestic proved reserves at December 31, 2012 are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. Domestic natural gas prices did result in a downward revision of proved reserves and a corresponding reduction in the discounted future net cash flows from our natural gas proved reserves. This downward revision was offset by the company's emphasis on the development of oil reserves. The result was a slight downward revision in total proved equivalent reserves, but an increase in overall reserves value.

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Results of Operations. Results of operations for oil and natural gas producing activities for the successor period from February 14, 2012 (inception) to December 31, 2012 and the predecessor periods from January 1, 2012 to May 24, 2012 and years ended December 31, 2011 and 2010 (in millions):

	U.S.	Brazil and Egypt	Worldwide
Successor			
Consolidated from February 14, 2012 (inception) to December 31, 2012:			
Net Revenues(1) Sales to external customers	$ 933	$ 76	$ 1,009
Costs of products and services	(88)		(88)
Production costs(2)	(160)	(32)	(192)
Depreciation, depletion and amortization(3)	(250)	(8)	(258)
Exploration expense	(45)	(7)	(52)
Results of operations from producing activities	$ 390	$ 29	$ 419
Unconsolidated Affiliate Four Star from February 14, 2012 (inception) 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	$ 46	$ 470
Affiliated sales	143		143
Total	567	46	613
Costs of products and services	(49)		(49)
Production costs(2)	(115)	(21)	(136)
Ceiling test charges(6)		(62)	(62)
Depreciation, depletion and amortization(3)	(301)	(12)	(313)
	102	(49)	53
Income tax expense	(37)		(37)
Results of operations from producing activities	$ 65	$ (49)	$ 16
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

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2011 Consolidated:						
Net Revenues(1)						
Sales to external customers	$	837	$	111	$	948
Affiliated sales		634				634
Total		1,471		111		1,582
Costs of products and services		(91)		(5)		(96)
Production costs(2)		(245)		(53)		(298)
Ceiling test charges(6)				(152)		(152)
Depreciation, depletion and amortization(3)		(563)		(32)		(595)
		572		(131)		441
Income tax expense		(207)				(207)
Results of operations from producing activities	$	365	$	(131)	$	234
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
2010 Consolidated:						
Net Revenues(1)						
Sales to external customers	$	551	$	86	$	637
Affiliated sales		743				743
Total		1,294		86		1,380
Costs of products and services		(81)		(5)		(86)
Production costs(2)		(218)		(46)		(264)
Ceiling test charges(6)				(25)		(25)
Depreciation, depletion and amortization(3)		(432)		(28)		(460)
		563		(18)		545
Income tax expense		(204)				(204)
Results of operations from producing activities	$	359	$	(18)	$	341
2010 Unconsolidated Affiliate Four Star(4):						
Net Revenues Sales to external customers	$	119	$		$	119
Costs of products and services		(4)				(4)
Production costs(2)		(36)				(36)
Depreciation, depletion and amortization(5)		(28)				(28)
Asset impairment		(4)				(4)
		47				47
Income tax expense		(17)				(17)

Results of operations from producing activities	$ 30	$	$ 30

(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.

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(3) Includes accretion expense on asset retirement obligations of $9 million for the successor period from February 14, 2012 (inception) to December 31, 2012, $5 million, $13 million and $16 million for the predecessor periods from January 1, 2012 to May 24, 2012 and the years ended December 31, 2011 and 2010, respectively.

(4) Results do not include amortization of $7 million for the successor period from February 14, 2012 (inception) to December 31, 2012 and $12 million, $34 million and $38 million for the predecessor periods from January 1, 2012 to May 24, 2012 and years ended December 31, 2011 and 2010 related to cost in excess of our equity interest in the underlying net assets of Four Star.

(5) Includes accretion expense on asset retirement obligations of $1 million for the successor period from February 14, 2012(inception) to December 31, 2012 and $1 million, $2 million and $1 million for the predecessor periods from January 1, 2012 to May 24, 2012 and the years ended December 31, 2011 and 2010, respectively.

(6) Includes $62 million of non-cash charges related to Egypt unevaluated costs for the predecessor period from January 1, 2012 to May 24, 2012, $152 million related to Brazil for the year ended December 31, 2011 and $25 million non-cash charges related to Egypt unevaluated costs for the year ended December 31, 2010.

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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
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
2010 Consolidated:			
Future cash inflows(1)	$ 17,145	$ 659	$ 17,804
Future production costs	(4,768)	(325)	(5,093)
Future development costs	(3,249)	(67)	(3,316)
Future income tax expenses	(2,403)	(9)	(2,412)
Future net cash flows	6,725	258	6,983
10% annual discount for estimated timing of cash flows	(2,905)	(77)	(2,982)
Standardized measure of discounted future net cash flows	$ 3,820	$ 181	$ 4,001
2010 Unconsolidated Affiliate Four Star(3):			

Future cash inflows(1)	$	943	$	$	943
Future production costs		(404)			(404)
Future development costs		(34)			(34)
Future income tax expenses		(192)			(192)
Future net cash flows		313			313
10% annual discount for estimated timing of cash flows		(131)			(131)
Standardized measure of discounted future net cash flows	$	182	$	$	182

(1) The company had no commodity-based derivative contracts designated as accounting hedges at December 31, 2012, 2011 and 2010. Amounts also exclude the impact on future net cash flows of derivatives not designated as accounting hedges.

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(2)
For the year ended December 31, 2012, there were no U.S. future income taxes because the company is not subject to federal income taxes.

(3)
Amounts represent our approximate 49 percent equity interest in Four Star.

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)		
	2012	2011	2010
Consolidated:			
Sales and transfers of oil and natural gas produced net of production costs	$ (1,433)	$ (1,200)	$ (1,042)
Net changes in prices and production costs	(871)	1,057	1,734
Extensions, discoveries and improved recovery, less related costs	2,539	2,140	986
Changes in estimated future development costs	978	(415)	(226)
Previously estimated development costs incurred during the period	587	601	199
Revision of previous quantity estimates	(1,863)	49	315
Accretion of discount	731	430	220
Net change in income taxes	1,683	(599)	(934)
Purchases of reserves in place			73
Sales of reserves in place	(296)	(587)	(47)
Change in production rates, timing and other	(210)	(261)	(19)
Net change	$ 1,845	$ 1,215	$ 1,259
Unconsolidated Affiliate Four Star:			
Sales and transfers of oil and natural gas produced net of production costs	$ (48)	$ (74)	$ (83)
Net changes in prices and production costs	(112)	62	70
Extensions, discoveries and improved recovery, less related costs	25		1
Changes in estimated future development costs	5	(14)	(1)
Revision of previous quantity estimates	19	6	16
Accretion of discount	22	22	18
Net change in income taxes	39	(9)	(16)
Change in production rates, timing and other	(8)	19	15
Net change	$ (58)	$ 12	$ 20
Representative NYMEX prices:(2)			
Oil (Bbl)	$ 94.61	$ 96.19	$ 79.43
Natural gas (MMBtu)	$ 2.76	$ 4.12	$ 4.38
Aggregate International prices:(2)			
Oil (Bbl)	$ 111.21	$ 109.29	$ 79.02
Natural gas (MMBtu)	$ 7.53	$ 5.31	$ 5.20

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

(2)
Estimated future cash inflows from estimated future production of proved reserves were computed using a first day 12-month average U.S. price and an aggregate international price.

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Shares

EP ENERGY CORPORATION

Common Stock

PROSPECTUS

, 2013

Until , 2013 (25 days after the date of this prospectus), all dealers effecting transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as an underwriter and with respect to their unsold allotments or subscriptions.

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PART II. INFORMATION NOT REQUIRED IN THE PROSPECTUS

Item 13. Other Expenses of Issuance and Distribution

The following table sets forth the estimated fees and expenses, other than underwriting discounts and commissions, paid or payable by the registrant in connection with the issuance and distribution of the common stock. All amounts are estimates except for the SEC registration, Financial Industry Regulatory Authority, Inc. and stock exchange and listing fees.

SEC registration fee	$ 13,640
Stock exchange filing fee and listing fee	*
Transfer agent and registrar fees	*
Printing and engraving costs	*
Legal fees and expenses	*
Accountants' fees and expenses	*
Financial Industry Regulatory Authority, Inc. filing fee	*
Miscellaneous	*
Total	*

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* To be filed by amendment.

Item 14. Indemnification of Directors and Officers

Section 145 of the Delaware General Corporation Law permits a Delaware corporation to indemnify its officers, directors and other corporate agents to the extent and under the circumstances set forth therein. Our Second Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws provide that we will indemnify any person who was or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding whether civil, criminal, administrative or investigative, by reason of the fact that he is or was our director, officer or board observer, or is or was serving at our request as a director, officer, employee or agent of another corporation, partnership, joint venture, trust or other enterprise, in accordance with provisions corresponding to Section 145 of the Delaware General Corporation Law. These indemnification provisions may be sufficiently broad to permit indemnification of the registrant's executive officers and directors for liabilities, including reimbursement of expenses incurred, arising under the Securities Act.

Pursuant to Section 102(b)(7) of the Delaware General Corporation Law, our Second Amended and Restated Certificate of Incorporation eliminates the personal liability of a director to us or our stockholders for monetary damages for a breach of fiduciary duty as a director, except for liability:

- for any breach of the director's duty of loyalty to us or our stockholders,;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- under Section 174 of the Delaware General Corporation Law (or any successor provision thereto); and
- for any transaction from which the director derived any improper personal benefit.

The above discussion of Section 145 of the Delaware General Corporation Law and of our Second Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws is not intended to be exhaustive and is respectively qualified in its entirety by Section 145 of the Delaware General Corporation Law, our Second Amended and Restated Certificate of Incorporation and Amended and Restated Bylaws.

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As permitted by Section 145 of the Delaware General Corporation Law, we will carry primary and excess insurance policies insuring our directors and officers against certain liabilities they may incur in their capacity as directors and officers. Under the policies, the insurer, on our behalf, may also pay amounts for which we granted indemnification to our directors and officers.

In addition, the underwriting agreement to be filed as Exhibit 1.1 to this Registration Statement provides that the underwriters will indemnify us and our executive officers and directors for certain liabilities related to this offering, including liabilities arising under the Securities Act.

Item 15. Recent Sales of Unregistered Securities

In May 2012 and June 2012, $3.3 billion and 24.0 million, respectively, in cash was paid to our predecessor in interest, EPE Acquisition, and EPE Acquisition issued 3.3 million Class A units representing membership interests in EPE Acquisition to the Legacy Class A Stockholders or their predecessors in interest (as applicable), and 0.8 million Class B units representing membership interests in EPE Acquisition to the Legacy Class B Stockholder.

On August 30, 2013, in connection with our Corporate Reorganization, (i) certain of the Legacy Class A Stockholders contributed their Class A units to us in exchange for the issuance of a like number of common stock to such holders, (ii) certain other Legacy Class A Stockholders, which previously held their Class A membership interests in EPE Acquisition indirectly through Blocker Vehicles, contributed their interests in their Blocker Vehicles to us in exchange for the issuance to such indirect holders of a like number of shares of common stock and (iii) the Legacy Class B Stockholders contributed their interests to us in exchange for the issuance of shares of Class B common stock. These securities were issued by us in reliance upon the exemption from the registration requirements provided by Section 4(a)(2) of the Securities Act.

Additional shares of Class B common stock were issued to EPE Employee Holdings II, LLC, a vehicle through which we will grant incentive awards to our current and future employees. These securities were issued by us in reliance upon the exemption from the registration requirements provided by Section 4(a)(2) of the Securities Act.

Item 16. Exhibits and Financial Statement Schedules

(a)

Exhibits
See the Exhibit Index immediately following the signature page hereto, which is incorporated by reference as if fully set forth herein.

(b)

Financial Statement Schedules

Not applicable.

Item 17. Undertakings

The undersigned registrant hereby undertakes to provide to the underwriters at the closing specified in the Underwriting Agreement certificates in such denominations and registered in such names as required by the underwriters to permit prompt delivery to each purchaser.

Insofar as indemnification for liabilities arising under the Securities Act of 1933 (the "Securities Act") may be permitted to directors, officers and controlling persons of the registrant pursuant to the foregoing provisions, or otherwise, the registrant has been advised that in the opinion of the SEC such indemnification is against public policy as expressed in the Securities Act and is, therefore, unenforceable. In the event that a claim for indemnification against such liabilities (other than the payment by the registrant of expenses incurred or paid by a director, officer or controlling person of the Registrant in the successful defense of any action, suit or proceeding) is asserted by such director,

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officer or controlling person in connection with the securities being registered, the registrant will, unless in the opinion of its counsel the matter has been settled by controlling precedent, submit to a court of appropriate jurisdiction the question whether such indemnification by it is against public policy as expressed in the Securities Act and will be governed by the final adjudication of such issue.

The undersigned registrant hereby undertakes:

(1) For purposes of determining any liability under the Securities Act, the information omitted from the form of prospectus filed as part of this registration statement in reliance upon Rule 430A and contained in a form of prospectus filed by the Registrant pursuant to Rule 424(b)(1) or (4) or 497(h) under the Securities Act shall be deemed to be part of this registration statement as of the time it was declared effective.

(2) For the purpose of determining any liability under the Securities Act, each post-effective amendment that contains a form of prospectus shall be deemed to be a new registration statement relating to the securities offered therein, and the offering of such securities at that time shall be deemed to be the initial bona fide offering thereof.

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SIGNATURES

Pursuant to the requirements of the Securities Act of 1933, the registrant has duly caused this registration statement to be signed on its behalf by the undersigned, thereunto duly authorized, in Houston, Texas on the 4th day of September, 2013.

EP ENERGY CORPORATION
By: /s/ BRENT J. SMOLIK

Brent J. Smolik
President and Chief Executive Officer

POWER OF ATTORNEY

Each person whose signature appears below hereby constitutes and appoints Marguerite N. Woung-Chapman and Dane E. Whitehead, and each of them, his true and lawful attorney-in-fact and agent with full power of substitution and resubstitution, for him and his name place and stead, in any and all capacities, to execute any and all amendments (including post-effective amendments) to this registration statement, to sign any registration statement filed pursuant to Rule 462(b) of the Securities Act of 1933, and to cause the same to be filed with all exhibits thereto, and all documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and desirable to be done in and about the premises as fully and to all intents and purposes as the undersigned might or could do in person, hereby ratifying and confirming all acts and things that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Act of 1933, this registration statement has been signed below by the following persons in the capacities and on the dates indicated below.

Signature	Title	Date
/s/ BRENT J. SMOLIK Brent J. Smolik	President, Chief Executive Officer and Chairman of the Board (Principal Executive Officer)	September 4, 2013
/s/ DANE E. WHITEHEAD Dane E. Whitehead	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	September 4, 2013
/s/ FRANCIS C. OLMSTED III Francis C. Olmsted III	Vice President and Controller (Principal Accounting Officer)	September 4, 2013
/s/ RALPH ALEXANDER Ralph Alexander	Director	September 4, 2013
/s/ GREGORY A. BEARD Gregory A. Beard	Director	September 4, 2013

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Signature	Title	Date
/s/ JOSHUA J. HARRIS Joshua J. Harris	Director	September 4, 2013
/s/ SAM OH Sam Oh	Director	September 4, 2013
/s/ ILRAE PARK Ilrae Park	Director	September 4, 2013
/s/ ROBERT M. TICHIO Robert M. Tichio	Director	September 4, 2013
/s/ DONALD A. WAGNER Donald A. Wagner	Director	September 4, 2013
/s/ RAKESH WILSON Rakesh Wilson	Director	September 4, 2013

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Exhibit No.	Exhibit Description
1.1**	Form of Underwriting Agreement.
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*	Form of Second Amended and Restated Certificate of Incorporation of EP Energy Corporation.
3.2*	Form of Amended and Restated Bylaws of EP Energy Corporation.
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.
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).

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Exhibit No.	Exhibit Description
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.
5.1**	Opinion of Akin Gump Strauss Hauer & Feld LLP as to the legality of securities being registered.
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).

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Exhibit No.	Exhibit Description
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).
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	Transaction Fee Agreement, dated as of May 24, 2012, among 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 10.13 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
10.23	Management Fee Agreement, dated as of May 24, 2012, among 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 10.14 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on September 11, 2012).
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).

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Exhibit No.	Exhibit Description
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.
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.
10.34+*	Third Amended and Restated Limited Liability Company Agreement of EPE Employee Holdings, LLC dated as of August 30, 2013.
10.35+*	Third Amended and Restated Limited Liability Company Agreement of EPE Management Investors, LLC dated as of August 30, 2013.
10.36+*	Subscription Agreement, dated as of August 30, 2013, between EP Energy Corporation and EPE Management Investors, LLC.
10.37+**	2013 Omnibus Incentive Plan.
10.38*	Stockholders Agreement, dated as of August 30, 2013, between EP Energy Corporation and the stockholders party thereto.
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.
23.4**	Consent of Akin Gump Strauss Hauer & Feld LLP (contained in Exhibit 5.1).
24.1*	Powers of attorney (included on the signature page to this registration statement).
99.1	Ryder Scott Company, L.P. reserve audit report for EP Energy LLC as of December 31, 2012 (Exhibit 99.1 to EP Energy LLC's Annual Report on Form 10-K filed with the SEC on March 1, 2013).
99.2*	Ryder Scott Company, L.P. reserve audit report for EP Energy LLC as of June 30, 2013.

* Filed herewith

** To be filed by amendment

\+ Management contract or compensatory plan, contract or arrangement.