**As filed with the Securities and Exchange Commission on September 11, 2012**

**Registration No. 333-**

**UNITED STATES**

**SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

**FORM S-4**

**REGISTRATION STATEMENT**

**UNDER**

**THE SECURITIES ACT OF 1933**

**EP ENERGY LLC**

(Exact name of registrant as specified in its charter)

|  |  |  |
| --- | --- | --- |
| **DELAWARE** (State or other jurisdiction of Incorporation or organization) | **1311** (Primary Standard Industrial Classification Code Number) | **45-4871021** (I.R.S. Employer Identification No.) |

**1001 Louisiana Street**

**Houston, Texas 77002**

**713-997-1200**

(Address, including zip code, and telephone number, including area code, of registrant’s principal executive offices)

**EVEREST ACQUISITION FINANCE INC.**

(Exact name of registrant as specified in its charter)

|  |  |  |
| --- | --- | --- |
| **DELAWARE** (State or other jurisdiction of Incorporation or organization) | **1311** (Primary Standard Industrial Classification Code Number) | **45-4870996** (I.R.S. Employer Identification No.) |

**1001 Louisiana Street**

**Houston, Texas 77002**

**(713) 997-1200**

(Address, including zip code, and telephone number, including area code, of registrant’s principal executive offices)

**GUARANTORS LISTED ON SCHEDULE A HERETO**

(Address, including zip code, and telephone number, including area code, of registrant’s principal executive offices)

**Marguerite N. Woung-Chapman, Esq.**

**General Counsel**

**EP Energy LLC**

**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 a copy to:**

**Monica K. Thurmond, Esq.**

**Paul, Weiss, Rifkind, Wharton & Garrison LLP**

**1285 Avenue of the Americas**

**New York, New York 10019-6064**

**(212) 373-3000**

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

If the securities being registered on this form are being offered in connection with the formation of a holding company and there is compliance with General Instruction G, check the following box. 🞏

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

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 number of the earlier effective registration statement for the same offering. 🞏

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

If applicable, place an X in the box to designate the appropriate rule provision relied upon in conducting this transaction:

Exchange Act Rule 13e-4(i) (Cross-Border Issuer Tender Offer) 🞏

Exchange Act Rule 14d-1(d) (Cross-Border Third-Party Tender Offer) 🞏

**CALCULATION OF REGISTRATION FEE**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Title of each Class of Securities to be Registered** | **Amount to be Registered** | **Proposed Maximum Offering Price Per Note** | **Proposed Maximum Aggregate Offering Price(1)** | **Amount of Registration Fee(2)** |
| 6.875% Senior Secured Notes due 2019 | $750,000,000 | 100% | $750,000,000 | $85,950 |
| Guarantee of 6.875% Senior Secured Notes due 2019(3) | — | — | — | (4) |
| 9.375% Senior Notes due 2020 | $2,000,000,000 | 100% | $2,000,000,000 | $229,200 |
| Guarantee of 9.375% Senior Notes due 2020(3) | — | — | — | (4) |
| 7.750% Senior Notes due 2022 | $350,000,000 | 100% | $350,000,000 | $40,110 |
| Guarantee of 7.750% Senior Notes due 2022(3) | — | — | — | (4) |

(1) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(a) under the Securities Act of 1933, as amended (the “Securities Act”). The proposed maximum offering price is estimated solely for purpose of calculating the registration fee.

(2) Calculated pursuant to Rule 457(f) of the rules and regulations of the Security Act. Paid by wire transfer on September 6, 2012

(3) Each of EP Energy LLC’s wholly-owned domestic subsidiaries jointly, severally and unconditionally guarantees, the 6.875% Senior Secured Notes due 2019 on a senior secured basis, the 9.375% Senior Notes due 2020 on a senior unsecured basis and the 7.750% Senior Notes due 2022 on a senior unsecured basis.

(4) See Schedule A on the inside facing page for table of additional registrant guarantors. Pursuant to Rule 457(n) of the rules and regulations under the Securities Act, no separate fee for the guarantee is payable.

**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 or until the Registration Statement shall become effective on such date as the Commission, acting pursuant to said Section 8(a), may determine.**

**SCHEDULE A**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Guarantor** |  | **State or Other Jurisdiction of Incorporation or Organization** | **Address of Registrants’ Principal Executive Offices** | **IRS Employer Identification Number** |
| EP Energy Global LLC | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EP Energy Brazil, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EP Energy Preferred Holdings Company, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| MBOW Four Star, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EP Energy Management, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EP Energy Resale Company, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EP Energy Gathering Company, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EP Energy E&P Company, L.P. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |
| EPE Nominee Corp. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | 80‑0817606 |
| Crystal E&P Company, L.L.C. | | Delaware | 1001 Louisiana Street Houston, Texas 77002 | Not Applicable |

The primary standard industrial classification code number for each of the additional registrants is 1311.

**Subject to completion, dated September [ ], 2012**

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This preliminary prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

**PRELIMINARY PROSPECTUS**



**EP Energy LLC**

**Everest Acquisition Finance Inc.**

**Exchange Offer for**

**$750,000,000 6.875% Senior Secured Notes due 2019**

**$2,000,000,000 9.375% Senior Notes due 2020 and**

**$350,000,000 7.750% Senior Notes due 2022**

**The Notes and the Guarantees**

• We are offering to exchange $750,000,000 of our outstanding 6.875% Senior Secured Notes due 2019 and certain related guarantees, which we refer to collectively as the “initial senior secured notes,” for a like aggregate amount of our registered 6.875% Senior Secured Notes due 2019 and certain related guarantees, which we refer to collectively as the “senior secured exchange notes.” The senior secured exchange notes will be issued under an indenture dated as of April 24, 2012. We refer to the initial senior secured notes and the senior secured exchange notes collectively as the “senior secured notes.”

• We are offering to exchange $2,000,000,000 of our outstanding 9.375% Senior Notes due 2020 and certain related guarantees, which we refer to collectively as the “initial 2020 senior notes,” for a like aggregate amount of our registered 9.375% Senior Notes due 2020 and certain related guarantees, which we refer to collectively as the “senior 2020 exchange notes.” The senior 2020 exchange notes will be issued under an indenture dated as of April 24, 2012. We refer to the initial 2020 senior notes and the senior 2020 exchange notes collectively as the “senior 2020 notes.”

• We are offering to exchange $350,000,000 of our outstanding 7.750% Senior Notes due 2022 and certain related guarantees, which we refer to collectively as the “initial 2022 senior notes,” for a like aggregate amount of our registered 7.750% Senior Notes due 2022 and certain related guarantees, which we refer to collectively as the “senior 2022 exchange notes.” The senior 2022 exchange notes will be issued under an indenture dated as of August 13, 2012. We refer to the initial 2022 senior notes and the senior 2022 exchange notes collectively as the “senior 2022 notes.”

• We refer to the senior 2020 notes and the senior 2022 notes collectively or individually, as the context requires, as the “senior notes.”

• We refer to the initial senior secured notes, the initial 2020 senior notes and the initial 2022 senior notes collectively or individually, as the context requires, as the “initial notes.” We refer to the senior secured exchange notes, the senior 2020 exchange notes and the senior 2022 exchange notes collectively or individually, as the context requires, as the “exchange notes.” We refer to the initial notes and the exchange notes collectively as the “notes.”

• The senior secured exchange notes will mature on May 1, 2019. We will pay interest on the senior secured exchange notes semi-annually on May 1 and November 1 of each year, commencing on November 1, 2012, at a rate of 6.875% per annum, to holders of record on the April 15 or October 15 immediately preceding the interest payment date.

• The senior 2020 exchange notes will mature on May 1, 2020. We will pay interest on the senior 2020 exchange notes semi-annually on May 1 and November 1 of each year, commencing on November 1, 2012, at a rate of 9.375% per annum, to holders of record on the April 15 or October 15 immediately preceding the interest payment date.

• The senior 2022 exchange notes will mature on September 1, 2022. We will pay interest on the senior 2022 exchange notes semi-annually on March 1 and September 1 of each year, commencing on March 1, 2013, at a rate of 7.750% per annum, to holders of record on the February 15 or August 15 immediately preceding the interest payment date.

• The exchange notes will be guaranteed, jointly and severally, by our present and future direct or indirect wholly owned material domestic subsidiaries that guarantee our new senior secured reserve‑based revolving credit facility (the “RBL Facility”).

• The senior secured exchange notes and the related guarantees will be secured (i) on a first‑priority basis by a perfected pledge of the capital stock of all first-tier foreign subsidiaries of EP Energy LLC (the “Issuer”), Everest Acquisition Finance Inc. (the “Co-Issuer” and, together with the Issuer, the “Issuers”) and each of the guarantors (which pledge will be limited to 65% of the voting capital stock and 100% of the non-voting capital stock of each such subsidiary) (the “Secured Notes/Term Loan Priority Collateral”); and (ii) on a second‑priority basis by all of the other assets securing the RBL Facility (including a perfected pledge of all of the capital stock of each direct, wholly owned, domestic, material restricted subsidiary of each of the Issuers and the guarantors), subject to exceptions described herein.

**Terms of the Exchange Offer**

• The exchange offer will expire at midnight, New York City time, on , 2012, unless we extend it.

• If all the conditions to this exchange offer are satisfied, we will exchange all of our initial notes that are validly tendered and not withdrawn for the exchange notes.

• You may withdraw your tender of initial notes at any time before the expiration of this exchange offer.

• The exchange notes that we will issue you in exchange for your initial notes will be substantially identical to your initial notes except that, unlike your initial notes, the exchange notes will have no transfer restrictions or registration rights.

• The exchange notes that we will issue you in exchange for your initial notes are new securities with no established market for trading.

**Before participating in this exchange offer, please refer to the section in this prospectus entitled “Risk Factors” beginning on page 34.**

**Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.**

We have not applied, and do not intend to apply, for listing the notes on any national securities exchange or automated quotation system.

Each broker‑dealer that receives exchange notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of those exchange notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker‑dealer will not be deemed to admit that it is an “underwriter” within the meaning of the Securities Act of 1933, as amended (the “Securities Act”). This prospectus, as it may be amended or supplemented from time to time, may be used by a broker‑dealer in connection with resales of exchange notes received in exchange for initial notes where those initial notes were acquired by that broker‑dealer as a result of market‑making activities or other trading activities. We have agreed that, for a period of 180 days after the expiration date, we will make this prospectus available to any broker‑dealer for use in connection with any such resale. See “Plan of Distribution.”

The date of this prospectus is , 2012.

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**PRESENTATION OF FINANCIAL INFORMATION**

EP Energy LLC (the “Issuer” and “Successor” and formerly known as Everest Acquisition LLC) was formed as a Delaware limited liability company on March 23, 2012 by Apollo Global Management LLC (Apollo) and other private equity investors (collectively, the Sponsors). On May 24, 2012, the Sponsors acquired EP Energy Global LLC, (the “Predecessor” and 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 as contemplated by the merger agreement among El Paso Corporation (“El Paso”) and Kinder Morgan, Inc. (“KMI”). 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 other international activities in Brazil and Egypt (Egypt was sold in June 2012) and together constituted the oil and natural gas operations of El Paso.

We present historical financial information prior to May 24, 2012, relating to EP Energy Global LLC and its consolidated subsidiaries in this prospectus. Following the acquisition, EP Energy Global LLC is a wholly owned subsidiary of the Issuer and is the predecessor of the Issuer for accounting purposes. Accordingly, its financial statements are presented for the historical periods prior to the Acquisition Transactions (as defined herein). The Issuer conducts all of its operations through EP Energy Global LLC and other subsidiaries that were subsidiaries of EP Energy Global LLC at the time of the historical financial statements presented in this prospectus and that were spun out of EP Energy Global LLC prior to the closing of the Acquisition Transactions.

Historical financial results in this prospectus for the periods before and after the Acquisition on May 24, 2012, have been presented separately for the predecessor and successor in accordance with required GAAP presentation. Despite this separate GAAP presentation, the successor had no independent oil and gas operations prior to the acquisition and accordingly there were no operational exploration and production activities changed as a result of the acquisition of the Predecessor. Consequently, given the continuity of operations, when assessing certain sections in our *Management’s Discussion and Analysis* (e.g. variance analysis, operating statistics) and pro forma financial information for the periods presented throughout this prospectus, we have presented a combined analysis of the pre-acquisition results of operations of the Predecessor and the post-acquisition results of operations of the Successor. We believe that reflecting this combined information and analysis, while non-GAAP, facilitates the most meaningful comparison and understanding of our operating performance in 2012 over the same period in the prior year and the pro forma results of our operations.

**USE OF NON-GAAP FINANCIAL INFORMATION**

We use the non-GAAP financial measures of Reported EBITDA, Adjusted EBITDAX, Cash Operating Costs /Adjusted Cash Operating Costs, Reserve Replacement Costs / Reserve Replacement Ratio, and PV-10. We believe these are supplemental measures and provide meaningful information to our investors; however, due to the limitations of these measures as analytical tools, we rely primarily on our GAAP results. Each of these non-GAAP measures is further described below or as further noted.

*Reported EBITDA and Adjusted EBITDAX.* Reported EBITDA is defined as net income plus interest and debt expense, income taxes and depreciation, depletion and amortization. Adjusted EBITDAX is defined as Reported EBITDA, 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), ceiling test charges or other impairments, adjustments to reflect cash distributions of the earnings from our unconsolidated affiliates, non-cash equity based compensation expenses, transition and restructuring costs we expect not to recur, advisory fees paid to our sponsors and exploration expenses.

We believe that the presentation of Reported EBITDA and 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) (v) and supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future.

Reported EBITDA and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under U.S. GAAP or as an alternative to net income, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. For example, our presentation of Reported EBITDA and Adjusted EBITDAX may not be comparable to similarly titled measures used by other companies in our industry. Furthermore, our presentation of Reported EBITDA and Adjusted EBITDAX should not be construed as an inference that our future results will be unaffected by the items noted above or what we believe to be other unusual or non-recurring items or that in the future we may not incur expenses that are the same as or similar to some of the adjustments in this presentation.

*Cash Operating Costs / Adjusted Cash Operating Costs.* We monitor cash operating costs required to produce our oil and natural gas production volumes. Cash operating costs is a non-GAAP measure calculated on a per Mcfe basis and includes total operating expenses less depreciation, depletion and amortization expense, ceiling test and other impairment charges, exploration expense, and transportation costs and costs of products. Adjusted cash operating costs reflects cash operating costs adjusted for non-recurring transition and restructuring costs, advisory fees paid to our sponsors and non-cash equity based compensation expense. We believe cash operating costs and adjusted cash operating costs per unit are valuable measures to provide management and investors reflecting operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies and are subject to several of the same limitations as analytical tools as noted in the paragraphs above.

*Reserve Replacement Ratio/Reserve Replacement Costs.* We calculate two primary metrics, (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 key asset areas. 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. For a further discussion of these measures, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

*PV-10.* PV-10 is considered a non-GAAP measure and is derived from the standardized measure of discounted future net cash flows of our oil and natural gas properties, which is the most directly comparable GAAP financial measure. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the relative monetary significance of our oil and natural gas 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 and natural gas 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, natural gas and NGL reserves.

**PRESENTATION OF RESERVES INFORMATION**

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, 2011, we engaged Ryder Scott Company, L.P., an independent petroleum engineering 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. Equivalent volumes are computed with oil and natural gas liquids quantities converted to Mcfe at a ratio of one Bbl to six Mcf, and natural gas converted to Boe at a ratio of six Mcf to one Bbl. 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.

**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 “Unaudited Pro Forma Condensed Consolidated Financial Data” and the historical financial statements and related notes presented elsewhere in this prospectus.*

*Unless otherwise indicated or the context otherwise requires, references in this prospectus to “we,” “our,” “us,” and the “Company” refer to EP Energy LLC (formerly known as Everest Acquisition LLC) (the “Issuer”) and each of its consolidated subsidiaries, including Everest Acquisition Finance Inc. (the “Co-Issuer” and, together with the Issuer, the “Issuers”). References in this prospectus to the “Sponsors” refer to the entities described under “—Our Sponsors” and their respective affiliates. You should carefully consider all information in this prospectus, including the matters discussed in “Risk Factors.” Financial information identified in this prospectus as “pro forma” gives effect to the closing of the Acquisition and Refinancing Transactions, which are described in this prospectus summary under “—The Acquisition Transactions” and “—The Refinancing Transactions.” 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.*

**Our Company**

We are one of North America’s leading independent oil and natural gas producers. We have a large and diverse base of producing assets that provides cash flow to fund the development of our key programs, which at this time are primarily oil-focused. Over the last several years, we have high-graded our future drilling inventory by establishing large acreage positions with repeatable drilling opportunities and more favorable return characteristics. Domestically, we currently operate through three divisions: Central, Eagle Ford and Southern, and have a strategic presence in well-known oil resource areas, including the Eagle Ford Shale, the Altamont Field, the Wolfcamp Shale and the South Louisiana Wilcox area. Our large and diverse producing gas assets include our Haynesville Shale position, substantially all of which is held by production, which gives us a significant presence in unconventional natural gas. We also have a small international presence in Brazil.

Our management team, which has been with us since at least 2007, has an average of 22 years of experience in the oil and gas industry and technical and operating expertise across our geographic regions. Our management team has a track record of identifying, acquiring and developing low-risk, repeatable resource opportunities and has executed a multi-year effort to add assets that fit our competencies. Today, our substantial key program drilling inventory encompasses approximately 4,500 locations and more than 20 years of drilling activity at our current pace. We have operational control over approximately 77% of our producing wells and 88% of our key program drilling inventory as of December 31, 2011. This control has allowed us to continually improve our capital and operating efficiencies. In 2011, we drilled 233 gross wells domestically (182 net to our ownership interests (“net”)) with a success rate of 100%, adding approximately 1,100 Bcfe of proved reserves at a replacement cost of $1.43 per Mcfe, the majority of which was oil.

As of December 31, 2011, we had proved reserves of approximately 4.0 Tcfe with a pre‑tax PV-10 of approximately $7 billion (of which approximately 54% of the PV‑10 was attributed to proved developed producing reserves). We had 182 MMBbls of proved oil reserves, 19 MMBbls of proved NGL reserves and 2,782 Bcfe of proved natural gas reserves, representing 27%, 3% and 70%, respectively, of our total proved reserves. Given the recent commodity price environment, we have shifted our focus primarily to developing our key oil programs, resulting in 48% of our revenues (excluding realized and unrealized gains on financial derivatives) being contributed by oil and NGLs in the fourth quarter of 2011, versus 34% in the fourth quarter of 2010. Our oil production for the month of December 2011 was approximately 24,000 Bbls/d, which contributed to our approximate 50% year-over-year growth in oil production for the fourth quarter of 2011. We anticipate that approximately 91% of our capital expenditures for 2012 will be allocated to oil-focused key programs. For the six month period ended June 30, 2012, 57% of our revenues (excluding realized and unrealized gains on financial derivatives) were contributed by oil and NGLs, versus 35% during the same period in 2011. For the month of June 2012, our oil production was approximately 27,000 Bbls/d.

For the six months ended June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, we generated Adjusted EBITDAX of $655 million on average daily production of 906 MMcfe/d. See “—Summary Historical and Pro Forma Consolidated Financial and Other Operating Data” for our definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to amounts reported under GAAP.

The following table provides summary data for each of our areas of operation:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **As of December 31, 2011** | | | | **As of June 30, 2012** |
|  | **Proved Reserves (Bcfe)** | **% Proved Developed** | **PV‑10** | **Net Acres** | **Average Daily Production (MMcfe/d)** |
|  | **(dollars in millions)** | | | | |
| **United States** |  |  |  |  |  |
| Central |  |  |  |  |  |
| Haynesville Shale | 903 | 34% | $719 | 41,000 | 317 |
| South Louisiana Wilcox | 31 | 48 | 143 | 183,000 | 16 |
| Altamont Field | 551 | 37 | 1,479 | 176,000 | 62 |
| Other Central | 1,117 | 75 | 998 | 1,339,000 | 208 |
| Eagle Ford |  |  |  |  |  |
| Eagle Ford Shale | 642 | 18 | 2,283 | 157,000 | 91 |
| Southern |  |  |  |  |  |
| Wolfcamp Shale | 148 | 12 | 337 | 138,000 | 10 |
| Other Southern(1) | 326 | 94 | 536 | 314,000 | 110 |
| Total United States | 3,718 | 48 | 6,495 | 2,348,000 | 814 |
| **International** |  |  |  |  |  |
| Brazil | 95 | 100 | 210 | 132,000 | 36 |
| Egypt(2) | — | — | — | 774,000 | — |
| Total Consolidated | 3,813 | 50 | 6,705 | 3,254,000 | 850 |
| **Unconsolidated Affiliate(3)** | 174 | 86 | 311 |  | 56 |
| Total Combined | 3,987 | 51 | $7,016 |  | 906 |

(1) Gulf of Mexico assets were sold in July 2012 and comprised reserves of 90 Bcfe, PV‑10 of $150 million, net acres of 233,000 and average daily production of 45 Mcfe/d.

(2) Sold in June 2012.

(3) Represents our approximate 49% equity interest in Four Star Oil & Gas Company (“Four Star”).

**Key Programs**

Over the past five years, our strategy has been to focus on areas that offer repeatable drilling programs, enabling us to reduce development costs, and to grow our asset base and inventory size. We have consistently improved the quality and increased the number of our drilling opportunities. During 2011, our principal focus was in the Haynesville Shale, the Eagle Ford Shale, the Wolfcamp Shale, the Altamont Field and South Louisiana Wilcox. We are redeploying the capital allocated to the Haynesville Shale to our oil programs. The technical and operating experience gained from our successful Haynesville program has been employed in our other key programs, including the Eagle Ford Shale.

***Haynesville Shale***

The initial execution of our strategy of repeatable drilling programs was in the Haynesville Shale, where we had existing conventional production as a result of historical development activities in east Texas and north Louisiana. Our operations in the Haynesville Shale are primarily focused in DeSoto Parish and Caddo Parish, Louisiana. We acquired additional leasehold interests through the acquisition of Peoples Energy Production Company in 2007. We piloted horizontally drilled wells in the Haynesville Shale, experimenting with different horizontal lateral lengths and fracture stimulation staging, with the objective of delivering optimal capital efficiency, finding costs and returns. High production rates in our Haynesville program combined with very low operating and development costs create competitive returns for us even at low natural gas prices. In addition, our acreage in the Haynesville Shale is predominately held by production, giving us the flexibility to pace our development and optimize our returns. Furthermore, our operations are surrounded by existing infrastructure, providing strong take-away access to markets. As of June 30, 2012, we had 66 net operated wells in this area. During the first quarter of 2012, although we had a very efficient drilling program in the Haynesville Shale, we suspended the program and released all rigs due to low natural gas prices.

***Eagle Ford Shale***

Beginning in late 2008, we were an early entrant in the Eagle Ford Shale, acquiring our interests through leasehold acquisitions for less than $1,000 per acre on average. Our operations in the Eagle Ford Shale are focused in LaSalle, Dimmit, Atascosa and Webb counties of south Texas. Overall, we hold rights to approximately 157,000 net acres across all Eagle Ford areas, where approximately 77,000 net acres are under development in our central Eagle Ford area. During 2010 and 2011, we improved the efficiency and productivity of our development program, reducing per-well capital costs by approximately 16% and drilling cycle time by more than 35% year over year. Most of our wells have had initial production rates that range from 600 to over 1,000 Boe/d, and our oil production in this area has grown significantly since the beginning of 2011. The Eagle Ford Shale currently provides the highest economic returns in our portfolio. Significant strengths of the Eagle Ford Shale also currently include a multi-year future drilling location inventory, favorable crude oil pricing relative to the West Texas Intermediate (“WTI”) index and a newly constructed midstream infrastructure with ample take-away capacity. As a result, the Eagle Ford Shale has become one of our key programs and a contributor to the increase in our oil reserves and production. As of December 31, 2011, we had 1,246 future drilling locations in the Eagle Ford Shale. As of June 30, 2012 we had 98 net operated wells and are currently running four rigs in the Eagle Ford Shale. We plan to add a fifth rig and drill 79 gross wells in 2012 based on our capital budget.

***Wolfcamp Shale***

In 2009 and 2010, we established a new major oil shale position by successfully leasing approximately 138,000 net acres in the Wolfcamp Shale in the Permian Basin in west Texas. Our operations in the Wolfcamp Shale are focused in Reagan, Crockett, Upton and Irion counties. We were an early entrant in the Wolfcamp Shale, acquiring our interests through leasehold acquisitions for less than $1,500 per acre on average. We have leveraged our technical and operating expertise, and in 2011 advanced our understanding of this area using the same approach and techniques that have allowed us to be successful in the Haynesville and Eagle Ford shales. As a result, in late 2011, we completed a 7,500 foot lateral well with 25 stages that tested at an initial production rate of 1,369 Boe/d, our highest initial production rate to date. In addition, the Wolfcamp Shale has high oil in place, a multi-year future drilling location inventory and favorable lease owner dynamics with the Texas University Land system as the predominant landowner. As of December 31, 2011, we had 983 future drilling locations in the Wolfcamp Shale. As of June 30, 2012, we had 26 net operated wells and are currently running one rig in the Wolfcamp Shale. We plan to drill 15 gross wells in 2012 based on our capital budget.

***Altamont Field***

In 2007, we commenced a reengineering effort in the Altamont Field in Utah, a legacy oil asset. Our operations in the Altamont Field are focused in the Uinta Basin. Altamont was initially developed in the 1970s, and we are applying current drilling and stimulation technology to vertically drill and develop this prolific oil area. We have enhanced the value of this field through infill drilling, for which we received regulatory approval in 2008. The Altamont Field has a multi-year inventory of future drilling locations, giving us a substantial opportunity for growth in oil production. Since our acreage is predominantly held by production, we have greater flexibility to improve both our costs and technical understanding of this area, while also growing returns. As of December 31, 2011, we had 1,336 future drilling locations in the Altamont Field. As of June 30, 2012, we had 307 net operated wells and are currently running two rigs in the Altamont Field. We plan to drill 21 gross wells in 2012 based on our capital budget.

***South Louisiana Wilcox***

In south Louisiana, we are developing our emerging South Louisiana Wilcox play. This is a relatively new oil-focused play that we have added to our drilling program. Our activity is located primarily in Beauregard Parish and is focused on the Wilcox Sands. We have over 1,000 square miles of 3-D seismic data in South Louisiana Wilcox, providing valuable information in selecting drilling locations. South Louisiana Wilcox is a conventional vertical well play that produces both oil and natural gas from a series of completed sands. A significant strength of South Louisiana Wilcox is its access to Louisiana Light Sweet Crude and Gulf Coast NGL pricing, which trade at a premium relative to the WTI index. In addition, the resource does not compete for horizontal drilling and completion services due to vertical drilling and completion design. As of December 31, 2011, we had 260 future drilling locations in South Louisiana Wilcox. As of June 30, 2012, we had 19 net operated wells and are currently running one rig in South Louisiana Wilcox. We plan to drill 15 gross wells in 2012 based on our capital budget.

**Other Gas Assets**

We have a large and diverse base of other domestic producing assets that provides cash flow to fund the development of our key programs. We do not anticipate a material portion of our 2012 capital expenditure budget to be spent on these assets.

***Arklatex/Unconventional***

Our Arklatex land positions comprise 104,470 total net acres focused on tight gas sands production. We have approximately 449,000 net acres in our unconventional plays. Our production is from vertical CBM wells development in Alabama, vertical and horizontal CBM wells in the Hartshorne coals in Oklahoma and the New Albany Shale in Indiana (sold in July 2012). We have high average working interests and long life reserves in these areas. For the six months ended June 30, 2012 we had average daily production of 119 MMcfe/d.

***Texas Gulf Coast/Gulf of Mexico***

We have significant assets in fields throughout the Texas Gulf Coast. In addition, prior to selling our Gulf of Mexico assets in July 2012, this area included interests in 69 Blocks offshore of the Louisiana, Texas and Alabama coastlines focused on deep targets (greater than 12,000 feet) in relatively shallow water depths (less than 400 feet). In these areas, we licensed over 8,700 square miles of 3D seismic data onshore and over 61,000 square miles of 3D seismic data offshore. As of December 31, 2011, these operations included 314,000 total net acres, and for the six months ended June 30, 2012 we had average daily production of 111 MMcfe/d.

***Raton Basin***

Our operations in the Raton Basin of northern New Mexico and southern Colorado, where we own the minerals beneath the Vermejo Park Ranch, are primarily focused on coal bed methane production. As of December 31, 2011, these operations included 606,000 total net acres, and for the six months ended June 30, 2012 we had average daily production of 81 MMcfe/d.

***Rocky Mountains***

We have a non-operated working interest in the County Line coal bed methane property in Wyoming, with additional non-producing acreage in Colorado, Wyoming, North Dakota and Utah. As of December 31, 2011, these operations included 179,000 total net acres, and for the six months ended June 30, 2012 we had average daily production of 9 MMcfe/d.

***Four Star***

We have an approximate 49% equity interest in Four Star. Production is from high quality conventional and coal bed methane assets in the San Juan, Permian, Hugoton and South Alabama basins and the Gulf of Mexico. For the first six months of 2012, our equity interest in Four Star’s daily equivalent natural gas production averaged approximately 56 MMcfe/d.

**2012 Capital Expenditures**

We have approved a capital expenditure budget between $1.5 billion and $1.6 billion for 2012, of which about $1.2 billion will be spent on drilling and completion activities. Our total oil and natural gas capital expenditures were $762 million for the six months ended June 30, 2012, of which $758 million were domestic capital expenditures. Our spending will be heavily weighted toward oil-focused reservoirs, which are forecasted to comprise 91% of our capital expenditures; our key programs will comprise 97% of our spending. A substantial portion of our capital expenditure budget is expected to be funded from operating cash flows, which should enable us to grow reserves and production while maintaining sufficient liquidity. We expect to periodically review our capital spending plans versus commodity prices and well performance and adjust spending as necessary. For example, the portion of our budget dedicated to gas-weighted resources has declined significantly in 2012, due primarily to reductions in Haynesville Shale activity as a result of low current natural gas prices.

|  |  |  |
| --- | --- | --- |
| **2012 Capex Budget** $1.5 Billion‑$1.6 Billion(1) | **Key Drilling Locations(2)** 4,498 Locations | **2012 Gross Wells Expected to Complete in Key Programs** 144 Gross Well |
|  |  |  |

(1) Includes approximately $100 million of capitalized interest, information technology and capitalized direct labor costs.

(2) As of December 31, 2011 (includes proved undeveloped (“PUD”) locations shown on a risked basis).

**Competitive Strengths**

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

**Large and Diverse Producing Asset Base**

Our vast resource base consists of approximately 4.0 Tcfe of proved reserves as of December 31, 2011 and are located on 3.3 million net acres. Approximately 1.7 Tcfe, or 42%, of our proved reserves are proved developed producing assets, and we generated an average of 838 MMcfe/d in 2011 from approximately 6,000 wells. During the first half of 2012, we generated an average of 906 MMcfe/d. Our existing assets are geographically diversified among many of the major basins of North America, insulating us to some extent from regional commodity pricing and costs dislocations that occur from time to time. Our producing assets provide a diverse source of cash flow to fund the development of our key programs, significantly reducing our reliance on outside sources of capital and improving our ability to replace and grow production in the future. While our existing producing assets are well diversified, we maintain a focused and concentrated approach that enables us to drive efficiencies, benefit from economies of scale, remain flexible in allocating capital to our most profitable projects and leverage our knowledge base from one project to the next.

**Extensive Inventory of Low-Risk Drilling Opportunities**

We have established a substantial resource base in unconventional oil plays to supplement our already significant inventory of unconventional natural gas resources. With our Eagle Ford and Wolfcamp shales, the ongoing development of our Altamont Field and the recent addition of South Louisiana Wilcox, we estimate we have more than 20 years of drilling inventory in approximately 4,500 drilling locations across our key programs, 85% of which are located in oil-focused reservoirs. The move to oil-focused reservoirs has allowed us to take advantage of higher oil prices and has improved cash flow through commodity diversity. The development of these assets will generate accelerated growth in oil production and reserves and provide us the flexibility to take advantage of strength in either gas or oil commodity price environments. We expect that the oil composition of our production will continue to increase as we develop our key oil programs over the next several years.

**Strong Financial Profile**

Our large and diverse portfolio produced 906 MMcfe/d in the six months ended June 30, 2012, which generated Adjusted EBITDAX of $655 million for the six months ended June 30, 2012. Pro forma for the Refinancing Transactions, as of June 30, 2012, we would have had approximately $1.6 billion of liquidity. Additionally, we maintain a robust hedging program that protects cash flows to fund development plans through the commodity cycle. As of August 20, 2012, our hedged volumes for 2012, 2013, 2014 and 2015 represent 85%, 79%, 38% and 16%, respectively, based on our total 2011 equivalent production.

**Low Cost and Efficient Operations**

We maintain a significant degree of operational control over our portfolio, operating approximately 77% of our producing wells and 88% of our key program drilling inventory as of December 31, 2011. Our operational efficiency has resulted in leading well cost performance in our key programs. Our three-year average reserve replacement cost of $1.55 per Mcfe ranks among the lowest among our peer group. Based on our operating efficiency, we believe our ability to generate significant cash flow in a variety of commodity price environments is enhanced, especially as our production profile becomes increasingly oil‑focused. We have reduced our domestic unit operating costs over the last several years by approximately $0.21 per Mcfe by lowering lifting costs, reducing subsurface, compression and disposal costs and divesting of high cost production areas. From 2007 to 2011, we reduced our unit lifting costs by approximately 28%. A lower cost structure should allow us to preserve returns and margins throughout the commodity cycle. Given our proven ability to find and develop reserves economically, we believe we should be able to convert our sizeable drilling portfolio at similar or better rates of return going forward.

**High Caliber Management Team with Proven Track Record**

Our senior management team, with an average of 22 years of experience, has a strong track record both at El Paso Corporation and in former leadership roles with Burlington Resources, ConocoPhillips and other leading producers. In addition, our operational team has significant experience in horizontal drilling and developing shales. We have an organizational structure that allows for greater ownership and accountability at the asset level through multi‑disciplined asset teams organized around our key geographic areas. Through a combination of invested equity and incentive programs, we believe our management and operational teams are motivated to deliver high returns and increase long-term value. We employ a centralized operational structure to accelerate the knowledge transfer around the execution of our drilling and completion programs and to continually enhance our field operations and base production performance. Our management and operational teams are focused on increasing our drilling opportunities and capital management and are motivated to ensure safe and reliable operations while delivering improved capital and operating efficiency. In addition, our supply chain management group enables us to partner with suppliers in order to improve the cost efficiency of services across the entire operation.

**Business Strategy**

Our strategy is to use our strengths to generate competitive returns from our capital investment programs by growing proved reserves, production volumes, and future drilling opportunities while optimizing our existing asset base. The key elements of this strategy are:

**Grow Our Production and Reserves with a Near-Term Focus on Oil**

Our primary focus is developing our key oil programs. We have a strategic presence in well-known oil resource areas, including the Eagle Ford Shale, the Altamont Field, the Wolfcamp Shale and South Louisiana Wilcox, and 85% of our key future drilling locations are in oil-focused areas. Our overall oil production volumes grew approximately 58% in the first six months of 2012 compared to the first six months of 2011, and our 2012 capital expenditure budget is heavily weighted toward oil-focused reservoirs, which comprise 91% of our capital expenditures.

**Continue to Leverage Technical and Operating Expertise to Develop Repeatable, Low-Risk Plays**

We plan to continue to evaluate new opportunities to gain scale and optimize our operating performance while leveraging our past experience to establish repeatable, low-risk plays in the future. Since our initial entry into the Haynesville Shale in 2007, we have drilled some of the most efficient wells in the area, and our production per well is among the best in the areas in which we operate. We entered the Eagle Ford and Wolfcamp shales through grassroots leasing efforts in late 2008 and applied the expertise gained from horizontal drilling in the Haynesville. We have subsequently leased large acreage positions in the Wolfcamp Shale, developed additional zones within our other key programs and have significantly improved the quality and number of our drilling opportunities.

**Continuously Improve Capital and Operating Efficiency**

We maintain a disciplined approach to spending that directs capital in a manner that seeks to maximize returns. Our large and diverse portfolio provides sufficient scale and diversity to conduct operations in a cost-efficient manner and reallocate capital as appropriate to maintain attractive returns. We have developed particular expertise as an operator of unconventional oil and natural gas plays. In each of our key programs, we have realized substantial reductions in drilling and completion costs and large improvements in cycle times by applying expertise from prior activities. For example, in the Eagle Ford Shale, we have quickly improved our efficiency and productivity, reducing capital costs by 16% and cycle time by more than 35% since the beginning of 2010.

**Maintain Financial Strength and Flexibility**

We intend to fund growth predominantly with internally generated funds while maintaining ample liquidity. As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, we would have had approximately $1.6 billion of liquidity. Our hedging program should further protect cash flows to provide sufficient funding levels for our capital program. In addition, consistent with past practices, we intend to continue to high-grade our asset base and remain opportunistic with respect to divesting other gas assets. As we pursue our strategy of developing high-return opportunities in our key programs, we expect our reserves to grow, thereby enhancing our liquidity and financial strength.

**Manage Commodity Price Volatility**

We maintain a robust hedging program designed to mitigate volatility in commodity prices and protect our enterprise cash flows. As of August 20, 2012, we have hedged for the remainder of 2012 a total of 4.6 MMBbls of oil at a weighted average price of $97.11 per Bbl and 103 TBtu of natural gas at a weighted average price of $4.47 per MMBtu. As of August 20, 2012, our hedged volumes for 2012, 2013, 2014 and 2015 represent 85%, 79%, 38% and 16%, respectively, based on our total 2011 equivalent production.

**Recent Events**

**The Acquisition Transactions**

***The Acquisition***

On February 24, 2012, EPE Acquisition, LLC, the indirect parent of the Company (“Parent” or “EPE Acquisition”), entered into a Purchase and Sale Agreement (the “Purchase and Sale Agreement”) with EP Energy Corporation, EP Energy Holding Company and El Paso Brazil, L.L.C. (collectively, the “Sellers”). Parent and the Issuers are controlled by investments funds affiliated with and controlled by Apollo Global Management, LLC, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation (collectively, the “Sponsors”). Pursuant to the Purchase and Sale Agreement, the Sellers agreed to sell, and Parent agreed to purchase: (i) all of the issued and outstanding membership interests of EP Energy Global LLC, a limited liability company resulting from the conversion of EP Energy Corporation into a limited liability company, which was renamed EP Energy Global LLC upon completion of the Acquisition Transactions (“EP Energy”); (ii) all of the issued and outstanding shares of El Paso E&P S. Alamein Cayman Company; (iii) all of the issued and outstanding quotas of UnoPaso Exploracao e Producao de Petroleo e Gas Ltda. and El Paso Oleo e Gas do Brasil Ltda.; and (iv) all of the issued and outstanding shares of El Paso Brazil Holdings Company (collectively, the “Acquired Business”). The Acquired Business includes all of El Paso Corporation’s exploration and production assets. As of the date of the Purchase and Sale Agreement, EP Energy Corporation owned all of the entities described in the preceding clauses (ii), (iii) and (iv). In connection with the Acquisition, a restructuring was completed, the result of which was that the entity described in clause (ii) above, together with its subsidiaries, shares common owners with EP Energy rather than being part of EP Energy. On May 24, 2012, we acquired the Acquired Business for a purchase price of approximately $7.2 billion, and the Issuer was renamed EP Energy LLC. The Acquired Business and the Co-Issuer comprise all of the assets of the Issuer. A portion of the Acquisition consideration was used by the Sellers to retire the Acquired Business’s existing reserve‑based credit facility and outstanding indebtedness. We refer to the purchase of the Acquired Business as the “Acquisition.”

The Sponsors, certain co-investors and certain members of management directly or indirectly own all of the equity interests of Parent.

***The Financing***

The Acquisition was financed with the following:

• a cash equity investment by the Sponsors and their co-investors in Parent of approximately $3,300 million;

• the net proceeds from the incurrence by the Issuers of $750 million of the initial senior secured notes;

• the net proceeds from the incurrence by the Issuers of $2,000 million of the initial 2020 senior notes;

• borrowing of $750 million by the Issuer under its new $750 million senior secured term loan facility; and

• borrowings of $750 million by the Issuer under its new $2,000 million senior secured reserve‑based revolving credit facility.

Throughout this prospectus, we collectively refer to the Acquisition, the investment in Parent’s equity, the consummation of the offering of the initial senior secured notes and the initial 2020 senior notes and the entry into the RBL Facility and the senior secured term facility and the borrowings thereunder, as the “Acquisition Transactions.”

**The Refinancing Transactions**

***7.750% Senior Notes due 2022***

On August 13, 2012, the Issuers issued $350.0 million aggregate principal amount of 7.750% senior notes due 2022 (the “initial 2022 senior notes”) through a private placement. We used the proceeds of the notes to repay a portion of our borrowings under the RBL Facility.

***Term Loan Repricing***

On August 21, 2012, we completed a repricing amendment of our senior secured term loan that reduced the LIBOR floor to 1.00% and the applicable margin applicable to the loans to 4.00%. In connection with the repricing amendment, we paid the lenders a fee equal to 1.00% of the principal amount of the loans affected by such amendment.

Throughout this prospectus, we collectively refer to the offering of the initial 2022 senior notes and the repricing of the senior secured term loan as the “Refinancing Transactions.”

**RBL Facility Amendment**

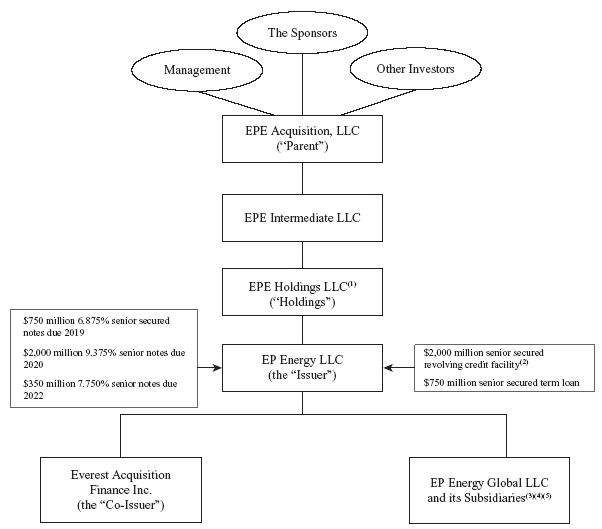
On August 17, 2012, we received requisite lenders’ consent and amended the RBL Facility to increase the general lien basket by $350 million in order to make the lien capacity thereunder consistent with the lien capacity under the notes and our other indebtedness, including the senior secured term loan.

**Sale of Egypt, Gulf of Mexico and Indiana Assets**

In June 2012, we completed the sale of our Egyptian operations, which were comprised of 774,000 net acres of non‑producing properties, for approximately $22 million in proceeds, representing an exit of our Egyptian exploration activities. In July 2012, we completed the sale of our Gulf of Mexico assets for approximately $79 million in proceeds, (a gross sales price of $103 million, less $24 million of purchase price adjustments.) The Gulf of Mexico assets had average daily production of approximately 45 MMcfe/d. At year end 2011, the Gulf of Mexico assets comprised approximately 2% or 90 Bcfe of our proved reserves. In addition, in July 2012, we sold our Indiana assets for approximately $6 million in proceeds.

**Corporate Structure**

The diagram below sets forth a simplified version of our organizational structure and our principal indebtedness following the exchange offer. This chart is provided for illustrative purposes only and does not represent all legal entities affiliated with, or all obligations of, the Issuers.



(1) EPE Holdings LLC has made a non-recourse pledge of the equity of the Issuer to secure the RBL Facility.

(2) As of September 1, 2012, $350 million was drawn and outstanding under the RBL Facility and our borrowings are limited to $1,913 million due to borrowing‑base restrictions under the agreement. See “Capitalization” for more information regarding borrowings and availability under the RBL Facility.

(3) All wholly owned material domestic subsidiaries of the Issuer guarantee and pledge certain assets under the RBL Facility, our senior secured term loan and the senior secured notes. These subsidiaries also guarantee the senior notes on a senior unsecured basis.

(4) As of June 30 2012, on a pro forma basis after giving effect to the Refinancing Transactions, non‑wholly owned subsidiaries, foreign subsidiaries and other subsidiaries of the Issuer that do not guarantee the notes hold approximately 2% of our consolidated assets and had no outstanding indebtedness, excluding intercompany obligations. During the six months ended June 30, 2012, on a pro forma basis after giving effect to Refinancing Transactions, these non-guarantor subsidiaries generated approximately 5% of our total revenue and 2% of our Adjusted EBITDAX.

(5) Includes our foreign operations in Brazil.

**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, 2012, Apollo had assets under management of approximately $105 billion in private equity, credit‑oriented capital markets and real estate funds invested across a core group of nine industries where Apollo has considerable knowledge and resources. Apollo’s team of more than 200 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 (“Riverstone”), founded in 2000, is an energy and power‑focused private equity firm with over $22 billion of equity capital raised across seven investment funds and co‑investments, including the world’s largest renewable energy fund. 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 $19.4 billion to 91 investments in North America, Latin America, Europe 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.

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.

In addition to our Sponsors, other co-investors participated in the Acquisition.

**Corporate Information**

Our principal executive offices are located at 1001 Louisiana Street, Houston, Texas 77002.

**Summary of the Exchange Offer**

In connection with the closing of the offering of the initial notes, we entered into registration rights agreements (as more fully described below) with the initial purchasers of the initial notes. You are entitled to exchange in the exchange offer your initial notes for exchange notes, which are identical in all material respects to the initial notes except that:

• the exchange notes have been registered under the Securities Act and will be freely tradable by persons who are not affiliated with us;

• the exchange notes are not entitled to the registration rights applicable to the initial notes under the registration rights agreements; and

• our obligation to pay additional interest on the initial notes due to the failure to consummate the exchange offer by a prior date does not apply to the exchange notes.

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| Exchange Offer | We are offering to exchange up to $750,000,000 aggregate principal amount of our senior secured exchange notes, up to $2,000,000,000 aggregate principal amount of our senior 2020 exchange notes and up to $350,000,000 aggregate principal amount of our senior 2022 exchange notes for a like aggregate principal amount of our initial senior secured notes, initial 2020 senior notes and initial 2022 senior notes, respectively. |
|  | In order to exchange your initial notes, you must properly tender them and we must accept your tender. We will exchange all outstanding initial notes that are validly tendered and not validly withdrawn. Initial notes may be exchanged only in denominations of $2,000 and integral multiples of $1,000 in excess thereof. |
| Expiration Date | This exchange offer will expire at midnight, New York City time, on , 2012, unless we decide to extend it. We do not currently intend to extend the expiration date. |
| Conditions to the Exchange Offer | The exchange offer is subject to customary conditions, some of which we may waive, that include the following conditions: |
|  | • there is no change in the laws and regulations which would impair our ability to proceed with this exchange offer, |
|  | • there is no change in the current interpretation of the staff of the SEC permitting resales of the exchange notes, |
|  | • there is no stop order issued by the SEC which would suspend the effectiveness of the registration statement which includes this prospectus or the qualification of the exchange notes under the Trust Indenture Act of 1939, |
|  | • there is no litigation or threatened litigation which would impair our ability to proceed with this exchange offer, and |
|  | • we obtain all the governmental approvals we deem necessary to complete this exchange offer. |
|  | Please refer to the section in this prospectus entitled “The Exchange Offer—Conditions to the Exchange Offer.” |
| Procedures for Tendering Initial Notes | To participate in this exchange offer, you must complete, sign and date the letter of transmittal or its facsimile and transmit it, together with your initial notes to be exchanged and all other documents required by the letter of transmittal, to Wilmington Trust, National Association, as exchange agent, at its address indicated under “The Exchange Offer—Exchange Agent.” In the alternative, you can tender your initial notes by book-entry delivery following the procedures described in this prospectus. For more information on tendering your initial notes, please refer to the section in this prospectus entitled “The Exchange Offer—Procedures for Tendering Initial Notes.” |
| Special Procedures for Beneficial Owners | If you are a beneficial owner of initial notes that are registered in the name of a broker, dealer, commercial bank, trust company or other nominee and you wish to tender your initial notes in the exchange offer, you should contact the registered holder promptly and instruct that person to tender on your behalf. |
| Guaranteed Delivery Procedures | If you wish to tender your initial notes and you cannot get the required documents to the exchange agent on time, you may tender your initial notes by using the guaranteed delivery procedures described under the section of this prospectus entitled “The Exchange Offer—Procedures for Tendering Initial Notes—Guaranteed Delivery Procedure.” |
| Withdrawal Rights | You may withdraw the tender of your initial notes at any time before midnight, New York City time, on the expiration date of the exchange offer. To withdraw, you must send a written or facsimile transmission notice of withdrawal to the exchange agent at its address indicated under “The Exchange Offer—Exchange Agent” before midnight, New York City time, on the expiration date of the exchange offer. |
| Acceptance of Initial Notes and Delivery of Exchange Notes | If all the conditions to the completion of this exchange offer are satisfied, we will accept any and all initial notes that are properly tendered in this exchange offer on or before midnight, New York City time, on the expiration date. We will return any initial note that we do not accept for exchange to you without expense promptly after the expiration date. We will deliver the exchange notes to you promptly after the expiration date and acceptance of your initial notes for exchange. Please refer to the section in this prospectus entitled “The Exchange Offer—Acceptance of Initial Notes for Exchange; Delivery of Exchange Notes.” |
| Federal Income Tax Considerations Relating to the Exchange Offer | Exchanging your initial notes for exchange notes should not be a taxable event to you for United States federal income tax purposes. Please refer to the section of this prospectus entitled “Certain U.S. Federal Income Tax Considerations.” |
| Exchange Agent | Wilmington Trust, National Association is serving as exchange agent in the exchange offer. |
| Fees and Expenses | We will pay all expenses related to this exchange offer. Please refer to the section of this prospectus entitled “The Exchange Offer—Fees and Expenses.” |
| Use of Proceeds | We will not receive any proceeds from the issuance of the exchange notes. We are making this exchange offer solely to satisfy certain of our obligations under our registration rights agreements entered into in connection with the offering of the initial notes. |
| Consequences to Holders Who Do Not Participate in the Exchange Offer | All untendered initial notes will continue to be subject to the restrictions on transfer provided for in the initial notes and in the applicable indenture. In general, the initial notes may not be offered or sold unless registered under the Securities Act, except pursuant to an exemption from, or in a transaction not subject to, the Securities Act and applicable state securities laws. Other than in connection with the exchange offer, we do not currently anticipate that we will register under the Securities Act any initial notes that remain outstanding after completion of the exchange offer. |
|  | Please refer to the section of this prospectus entitled “The Exchange Offer—Your Failure to Participate in the Exchange Offer Will Have Adverse Consequences.” |
| Resales of the Exchange Notes | Based on an interpretation by the staff of the SEC set forth in no-action letters issued to third parties, we believe that the exchange notes issued pursuant to the exchange offers in exchange for original notes may be offered for resale, resold and otherwise transferred by you (unless you are our “affiliate” within the meaning of Rule 405 under the Securities Act) without compliance with the registration and prospectus delivery provisions of the Securities Act, provided that you: |
|  | • are acquiring the exchange notes in the ordinary course of business; and |
|  | • have not engaged in, do not intend to engage in, and have no arrangement or understanding with any person or entity, including any of the Issuers’ affiliates, to participate in, a distribution of the exchange notes. |
|  | In addition, each participating broker‑dealer that receives exchange notes for its own account pursuant to the exchange offers in exchange for initial notes that were acquired as a result of market‑making or other trading activity must also acknowledge that it will deliver a prospectus in connection with any resale of the exchange notes. For more information, see “Plan of Distribution.” Any holder of initial notes, including any broker‑dealer, who |
|  | • is our affiliate, |
|  | • does not acquire the exchange notes in the ordinary course of its business, or |
|  | • tenders in the exchange offers with the intention to participate, or for the purpose of participating, in a distribution of exchange notes, |
|  | cannot rely on the position of the staff of the SEC expressed in Exxon Capital Holdings Corporation, Morgan Stanley & Co., Incorporated or similar no-action letters and, in the absence of an exemption, must comply with the registration and prospectus delivery requirements of the Securities Act in connection with the resale of the exchange notes. |
|  | Please refer to the sections of this prospectus entitled “The Exchange Offer—Procedures for Tendering Initial Notes—Proper Execution and Delivery of Letters of Transmittal,” “Risk Factors—Risks Relating to the Exchange Offer—Some persons who participate in the exchange offer must deliver a prospectus in connection with resales of the exchange notes” and “Plan of Distribution.” |

**Summary of Terms of the Exchange Notes**

*The summary below describes the principal terms of the exchange notes. Certain of the terms and conditions described below are subject to important limitations and exceptions. The “Description of Senior Secured Exchange Notes,” the “Description of Senior 2020 Exchange Notes” and the “Description of Senior 2022 Exchange Notes” sections of this prospectus contain more detailed descriptions of the terms and conditions of the exchange notes.*

**Senior Secured Exchange Notes**

|  |  |
| --- | --- |
| Issuers | EP Energy LLC (formerly known as Everest Acquisition LLC) and Everest Acquisition Finance Inc. |
| Notes Offered | $750,000,000 aggregate principal amount of 6.875% Senior Secured Notes due 2019. |
| Maturity Date | May 1, 2019. |
| Interest Rate | Interest on the senior secured exchange notes will accrue from April 24, 2012 at a rate of 6.875% per annum and will be payable in cash. |
| Interest Payment Dates | May 1 and November 1 of each year, commencing November 1, 2012. |
| Denominations | Minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof; provided that notes may be issued in denominations of less than $2,000 solely to accommodate book-entry positions that have been created by a DTC participant in denominations of less than $2,000. |
| Guarantees | Our obligations under the senior secured exchange notes will be fully and unconditionally guaranteed, jointly and severally, by the Issuers’ present and future direct or indirect wholly owned material domestic subsidiaries that guarantee the RBL Facility. |
| Ranking | The senior secured exchange notes will be our senior secured obligations and will: |
|  | • rank senior in right of payment to all of our existing and future debt and other obligations that are, by their terms, expressly subordinated in right of payment to the senior secured exchange notes; |
|  | • be effectively senior in right of payment to all of our existing and future unsecured indebtedness (including the senior notes) to the extent of the value of the collateral securing the senior secured exchange notes; |
|  | • be effectively subordinated to all of our existing and future secured debt that is secured on a first‑priority basis (including obligations under the RBL Facility), to the extent of the value of the RBL Facility Priority Collateral (as defined below); |
|  | • be equal to our senior secured term loan, which is secured on a pari passu basis with the senior secured exchange notes; and |
|  | • be structurally subordinated to all obligations of each of our subsidiaries that is not a guarantor of the senior secured exchange notes. |
|  | As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, the senior secured notes ranked (1) effectively junior to $400 million of first‑priority senior secured indebtedness under the RBL Facility to the extent of the RBL Facility Priority Collateral, (2) equally to $750 million of senior secured indebtedness under our new senior secured term loan, (3) effectively senior to $2,350 million of unsecured indebtedness represented by the senior notes and (4) effectively junior to no indebtedness of our non-guarantor subsidiaries. Further, we had approximately $1.5 billion available for additional borrowing under the RBL Facility, all of which would be secured on a first‑priority basis by a lien on the RBL Facility Priority Collateral. |
|  | As of June 30, 2012, non-wholly owned subsidiaries, foreign subsidiaries and other subsidiaries of the Issuer that do not guarantee the senior secured notes hold approximately 2% of our consolidated assets and have no outstanding indebtedness, excluding intercompany obligations. For the six months ended June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, these non-guarantor subsidiaries generated approximately 5% of our revenue and 2% of our Adjusted EBITDAX. |
| Security | The senior secured exchange notes will be secured: |
|  | • on a first‑priority basis by a perfected pledge of the capital stock of all first-tier foreign subsidiaries of the Issuers and each of the guarantors (which pledge will be limited to 65% of the voting capital stock and 100% of the non-voting capital stock of each such subsidiary) (the “Secured Notes/Term Loan Priority Collateral”); |
|  | • on a second‑priority basis by all of the other collateral securing the RBL Facility other than the capital stock of the Issuer and as set forth below, which includes: |
|  | • a perfected pledge of all of the capital stock of each material domestic restricted subsidiary held by the Issuers and each of the guarantors; |
|  | • perfected real property mortgages on oil and gas reserves of the Issuers and the guarantors located in the United States that are included in the reserve reports most recently delivered to the lenders under the RBL Facility; and |
|  | • substantially all other tangible (other than real property and other oil and gas properties) and intangible assets of the Issuers and the guarantors. |
|  | In this prospectus, we refer to the foregoing collateral that secures the RBL Facility on a first‑priority basis and the senior secured notes on a second‑priority basis as the “RBL Facility Priority Collateral.” For a further description of the RBL Facility Priority Collateral, see “Description of Other Indebtedness—The RBL Facility—Guarantees and Security.” |
|  | While the senior secured exchange notes will initially be secured by the pledge of the capital stock of the subsidiaries of the Issuers and the Guarantors as described above, these pledges will be released to the extent that separate financial statements pursuant to Rule 3-16 of Regulation S-X would be required in connection with the filing of the registration statement related to the senior secured exchange notes of which this prospectus forms a part. See “Description of Senior Secured Exchange Notes—Security—Limitations on Stock Collateral.” |
|  | The RBL Facility Priority Collateral and the Secured Notes/Term Loan Priority Collateral excludes: (i) any property or assets owned by any foreign subsidiaries, (ii) certain real property and oil and gas properties, (iii) motor vehicles, (iv) subject to limited exceptions, any assets or any right, title or interest in any license, contract or agreement to the extent that taking a security interest in any of them would violate any applicable law or regulation or any enforceable contractual obligation binding on the assets that existed at the time of the acquisition thereof and not created in connection with such acquisition (except in the case of assets owned on the date the initial senior secured notes are issued or that are subject to certain purchase money liens permitted under the indenture governing the senior secured notes) or would violate the terms of any such license, contract or agreement and (v) certain other limited assets. |
|  | For more information on the security granted, see “Description of Senior Secured Exchange Notes—Security.” The security interests in the assets securing the senior secured notes may be released under certain circumstances. See “Risk Factors—Additional Risks Related to the Senior Secured Notes,” “Description of Senior Secured Exchange Notes—Security—Intercreditor Agreements” and “Description of Senior Secured Exchange Notes—Security—Release of Collateral.” |
| Intercreditor Agreements | The security granted in the RBL Facility Priority Collateral to secure the senior secured notes and the senior secured term loan on a second‑priority basis is also granted to secure, on a first‑priority basis, indebtedness under the RBL Facility, and the security granted in the Secured Notes/Term Loan Priority Collateral to secure the senior secured notes and the senior secured term loan on a first‑priority basis will also be granted to secure, on a second‑priority basis, indebtedness under the RBL Facility. In addition, the indenture governing the senior secured notes permits us to secure additional indebtedness with liens on the RBL Facility Priority Collateral and the Secured Notes/Term Loan Priority Collateral under certain circumstances. The lenders under the RBL Facility and the holders of certain debt (including certain hedging and cash management counterparties) will receive priority treatment with respect to the proceeds of an enforcement of the security interest in or other recoveries from the RBL Facility Priority Collateral. These intercreditor relationships will be governed by an intercreditor agreement as described in more detail under the caption “Description of Senior Secured Exchange Notes—Security—Intercreditor Agreements—Senior Lien Intercreditor Agreement.” In addition, the agent for the senior secured term loan and the trustee for the senior secured notes entered into an intercreditor agreement governing the relationship between the lenders under our new senior secured term loan and holders of the senior secured notes as well as holders of any other indebtedness secured on a pari passu basis with the senior secured notes and the senior secured term loan. See “Description of Senior Secured Exchange Notes—Security—Intercreditor Agreements—Pari Passu Intercreditor Agreement.” |
| Optional Redemption | Prior to May 1, 2015, we may redeem some or all of the senior secured exchange notes at a redemption price equal to 100% of the principal amount of the senior secured exchange notes plus accrued and unpaid interest and additional interest, if any, to (but not including) the applicable redemption date plus the applicable “make-whole” premium. On or after May 1, 2015, we may redeem some or all of the senior secured exchange notes at the redemption prices set forth in this prospectus. Additionally, on or prior to May 1, 2015, we may redeem up to 35% of the aggregate principal amount of the senior secured exchange notes with the net proceeds of specified equity offerings at the redemption price set forth in this prospectus. See “Description of Senior Secured Exchange Notes—Optional Redemption.” |
| Certain Covenants | The indenture governing the senior secured exchange notes, among other things, limits our ability and the ability of our restricted subsidiaries to: |
|  | • incur or guarantee additional indebtedness; |
|  | • pay dividends or distributions on, or redeem or repurchase, capital stock and make other restricted payments; |
|  | • make investments; |
|  | • consummate certain asset sales; |
|  | • engage in transactions with affiliates; |
|  | • grant or assume liens; and |
|  | • consolidate, merge or transfer all or substantially all of our assets. |
|  | These limitations are subject to a number of important qualifications and exceptions as described under “Description of Senior Secured Exchange Notes—Certain Covenants.” Parent will not be subject to any of the covenants in the indenture governing the senior secured exchange notes. |
| Book-Entry Form | The senior secured exchange notes will be issued in registered book-entry form represented by one or more global notes to be deposited with or on behalf of DTC or its nominee. Transfers of the senior secured exchange notes will only be effected through facilities of DTC. Beneficial interests in the global notes may not be exchanged for certificated notes except in limited circumstances. See “Book-Entry; Delivery and Form.” |
| Risk Factors | You should consider all of the information contained in this prospectus before making an investment in the senior secured exchange notes. In particular, you should consider the risks described under “Risk Factors.” |

**Senior 2020 Exchange Notes**

|  |  |
| --- | --- |
| Issuers | EP Energy LLC (formerly known as Everest Acquisition LLC) and Everest Acquisition Finance Inc. |
| Notes Offered | $2,000,000,000 aggregate principal amount of 9.375% Senior Notes due 2020. |
| Maturity Date | May 1, 2020. |
| Interest Rate | Interest on the senior 2020 exchange notes will accrue from April 24, 2012 at a rate of 9.375% per annum and will be payable in cash. |
| Interest Payment Dates | May 1 and November 1 of each year, commencing November 1, 2012. |
| Denominations | Minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof; provided that notes may be issued in denominations of less than $2,000 solely to accommodate book-entry positions that have been created by a DTC participant in denominations of less than $2,000. |
| Guarantees | Our obligations under the senior 2020 exchange notes will be fully and unconditionally guaranteed, jointly and severally, by the Issuers’ present and future direct or indirect wholly owned material domestic subsidiaries that guarantee the RBL Facility. |
| Ranking | The senior 2020 exchange notes will be our senior unsecured obligations and will: |
|  | • rank equally in right of payment with all of our existing and future senior debt; |
|  | • rank senior in right of payment to all of our existing and future debt and other obligations that are, by their terms, expressly subordinated in right of payment to the senior 2020 exchange notes; |
|  | • be effectively subordinated to all of our existing and future secured debt (including obligations under the RBL Facility, our senior secured term loan and the senior secured notes), to the extent of the value of the assets securing such indebtedness, and |
|  | • be structurally subordinated to all obligations of each of our subsidiaries that is not a guarantor of the notes. |
|  | As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, the senior 2020 exchange notes ranked (1) effectively junior to $1,900 million of senior secured indebtedness, consisting of indebtedness outstanding under the RBL Facility, the senior secured term loan and the senior secured notes, (2) equally to $350 million of our senior 2022 notes and (3) effectively junior to no indebtedness of our non-guarantor subsidiaries. Further, we had approximately $1.5 billion available for additional borrowing under the RBL Facility, all of which would be secured. |
|  | As of June 30, 2012, non-wholly owned subsidiaries, foreign subsidiaries and other subsidiaries of the Issuer that do not guarantee the senior 2020 exchange notes hold approximately 2% of our consolidated assets and have no outstanding indebtedness, excluding intercompany obligations. For the six months ended June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, these non-guarantor subsidiaries generated approximately 5% of our total revenue and 2% of our Adjusted EBITDAX. |
| Optional Redemption | Prior to May 1, 2016, we may redeem some or all of the senior 2020 exchange notes at a redemption price equal to 100% of the principal amount of the senior 2020 exchange notes plus accrued and unpaid interest and additional interest, if any, to (but not including) the applicable redemption date plus the applicable “make-whole” premium. On or after May 1, 2016, we may redeem some or all of the senior 2020 exchange notes at the redemption prices set forth in this prospectus. Additionally, on or prior to May 1, 2015, we may redeem up to 35% of the aggregate principal amount of the senior 2020 exchange notes with the net proceeds of specified equity offerings at the redemption price set forth in this prospectus. See “Description of Senior 2020 Exchange Notes—Optional Redemption.” |
| Certain Covenants | The indenture governing the senior 2020 exchange notes, among other things, limits our ability and the ability of our restricted subsidiaries to: |
|  | • incur or guarantee additional indebtedness; |
|  | • pay dividends or distributions on, or redeem or repurchase, capital stock and make other restricted payments; |
|  | • make investments; |
|  | • consummate certain asset sales; |
|  | • engage in transactions with affiliates; |
|  | • grant or assume liens; and |
|  | • consolidate, merge or transfer all or substantially all of our assets. |
|  | These limitations are subject to a number of important qualifications and exceptions as described under “Description of Senior 2020 Exchange Notes—Certain Covenants.” Parent will not be subject to any of the covenants in the indenture governing the senior 2020 exchange notes. |
| Book-Entry Form | The senior 2020 exchange notes will be issued in registered book-entry form represented by one or more global notes to be deposited with or on behalf of DTC or its nominee. Transfers of the senior 2020 exchange notes will only be effected through facilities of DTC. Beneficial interests in the global notes may not be exchanged for certificated notes except in limited circumstances. See “Book-Entry; Delivery and Form.” |
| Risk Factors | You should consider all of the information contained in this prospectus before making an investment in the senior 2020 exchange notes. In particular, you should consider the risks described under “Risk Factors.” |

**Senior 2022 Exchange Notes**

|  |  |
| --- | --- |
| Issuers | EP Energy LLC and Everest Acquisition Finance Inc. |
| Notes Offered | $350,000,000 aggregate principal amount of 7.750% Senior Notes due 2022. |
| Maturity Date | September 1, 2022. |
| Interest Rate | Interest on the senior 2022 exchange notes will accrue from August 13, 2012 at a rate of 7.750% per annum and will be payable in cash. |
| Interest Payment Dates | March 1 and September 1 of each year, commencing March 1, 2013. |
| Denominations | Minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof; provided that notes may be issued in denominations of less than $2,000 solely to accommodate book-entry positions that have been created by a DTC participant in denominations of less than $2,000. |
| Guarantees | Our obligations under the senior 2022 exchange notes will be fully and unconditionally guaranteed, jointly and severally, by the Issuers’ present and future direct or indirect wholly owned material domestic subsidiaries that guarantee the RBL Facility. |
| Ranking | The senior 2022 exchange notes will be our senior unsecured obligations and will: |
|  | • rank equally in right of payment with all of our existing and future senior debt; |
|  | • rank senior in right of payment to all of our existing and future debt and other obligations that are, by their terms, expressly subordinated in right of payment to the senior 2022 exchange notes; |
|  | • be effectively subordinated to all of our existing and future secured debt (including obligations under the RBL Facility, our senior secured term loan and the senior secured notes), to the extent of the value of the assets securing such indebtedness, and |
|  | • be structurally subordinated to all obligations of each of our subsidiaries that is not a guarantor of the notes. |
|  | As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, the senior 2022 exchange notes ranked (1) effectively junior to $1,900 million of senior secured indebtedness, consisting of indebtedness outstanding under the RBL Facility, the senior secured term loan and the senior secured notes, (2) equally to $2,000 million of our senior 2020 notes and (3) effectively junior to no indebtedness of our non-guarantor subsidiaries. Further, we had approximately $1.5 billion available for additional borrowing under the RBL Facility, all of which would be secured. |
|  | As of June 30, 2012, non-wholly owned subsidiaries, foreign subsidiaries and other subsidiaries of the Issuer that do not guarantee the senior 2022 exchange notes hold approximately 2% of our consolidated assets and have no outstanding indebtedness, excluding intercompany obligations. For the six months ended June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, these non-guarantor subsidiaries generated approximately 5% of our total revenue and 2% of our Adjusted EBITDAX. |
| Optional Redemption | Prior to September 1, 2017, we may redeem some or all of the senior 2022 exchange notes at a redemption price equal to 100% of the principal amount of the senior 2022 exchange notes plus accrued and unpaid interest and additional interest, if any, to (but not including) the applicable redemption date plus the applicable “make-whole” premium. On or after September 1, 2017, we may redeem some or all of the senior 2022 exchange notes at the redemption prices set forth in this prospectus. Additionally, on or prior to September 1, 2015, we may redeem up to 35% of the aggregate principal amount of the senior 2022 exchange notes with the net proceeds of specified equity offerings at the redemption price set forth in this prospectus. See “Description of Senior 2022 Exchange Notes—Optional Redemption.” |
| Certain Covenants | The indenture governing the senior 2022 exchange notes, among other things, limits our ability and the ability of our restricted subsidiaries to: |
|  | • incur or guarantee additional indebtedness; |
|  | • pay dividends or distributions on, or redeem or repurchase, capital stock and make other restricted payments; |
|  | • make investments; |
|  | • consummate certain asset sales; |
|  | • engage in transactions with affiliates; |
|  | • grant or assume liens; and |
|  | • consolidate, merge or transfer all or substantially all of our assets. |
|  | These limitations are subject to a number of important qualifications and exceptions as described under “Description of Senior 2022 Exchange Notes—Certain Covenants.” Parent will not be subject to any of the covenants in the indenture governing the senior 2022 exchange notes. |
| Book-Entry Form | The senior 2022 exchange notes will be issued in registered book-entry form represented by one or more global notes to be deposited with or on behalf of DTC or its nominee. Transfers of the senior 2022 exchange notes will only be effected through facilities of DTC. Beneficial interests in the global notes may not be exchanged for certificated notes except in limited circumstances. See “Book-Entry; Delivery and Form.” |
| Risk Factors | You should consider all of the information contained in this prospectus before making an investment in the senior 2022 exchange notes. In particular, you should consider the risks described under “Risk Factors.” |

**Summary Historical and Pro Forma Consolidated Financial**

**and Other Operating Data**

Set forth below is the summary historical consolidated financial and other operating data of EP Energy Global LLC (formerly known as EP Energy Corporation and EP Energy, L.L.C.). See “Presentation of Financial Information,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the historical consolidated financial statements and the notes to those statements included elsewhere in this prospectus.

The following table sets forth summary historical financial and other data for the periods and as of the dates indicated. We have derived the consolidated statement of income and statement of cash flows data for the years ended December 31, 2011, 2010 and 2009 and the consolidated balance sheet data as of December 31, 2011 and 2010 from EP Energy Corporation’s audited consolidated financial statements included elsewhere in this prospectus. The summary consolidated balance sheet data as of December 31, 2009 has been derived from EP Energy Corporation’s audited consolidated financial statements not included herein.

The table below also includes the Issuer’s unaudited pro forma condensed consolidated statement of income data, giving pro forma effect to the Acquisition and Refinancing Transactions as described in “—Recent Events” if they had occurred on January 1, 2011. The unaudited pro forma condensed consolidated balance sheet has been prepared as if the Refinancing Transactions occurred on June 30, 2012. 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 for informational purposes only and do not purport to represent what our results of operations or financial position actually would have been if the Acquisition and Refinancing Transactions had occurred at any other date, and such data does not purport to project our results of operations for any future period.

The Acquisition was accounted for as a business combination using the acquisition method of accounting. Accordingly, the purchase price has been allocated to the assets acquired and liabilities assumed based upon management’s estimates of fair value. The unaudited pro forma condensed consolidated data are based upon available information and certain assumptions that management believes are factually supportable and that are reasonable under the circumstance. Because the determination of fair value is dependent upon valuations as of the Acquisition date, the unaudited pro forma condensed consolidated financial data may be revised and any such adjustments to the estimates of fair value may be material.

The following summary historical and pro forma financial and other data should be read in conjunction with the information included under the headings “—Recent Events,” “Unaudited Pro Forma Condensed Consolidated Financial Data,” “Selected Historical Consolidated Financial Data,” “Use of Proceeds,” “Capitalization” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and EP Energy Corporation’s audited consolidated financial statements and the related notes included elsewhere in this prospectus.

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **EP Energy LLC Pro Forma** | | **EP Energy Corporation** | | |
|  | **Six Months** |  | **Historical** | | |
|  | **ended June 30,** | **Year ended December 31,** | **Year ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
|  | **(dollars in millions)** | | | | |
| **Statement of income data** |  |  |  |  |  |
| Operating revenues: |  |  |  |  |  |
| Third parties | $756 | $1,582 | $948 | $634 | $552 |
| Affiliates | — | — | 634 | 746 | 545 |
| Realized and unrealized gains on financial derivatives(1) | 422 | 284 | 284 | 390 | 687 |
| Other | — | 1 | 1 | 19 | 44 |
| Total operating revenues | 1,178 | 1,867 | 1,867 | 1,789 | 1,828 |
| Operating expenses: |  |  |  |  |  |
| Cost of products | — | — | — | 15 | 31 |
| Transportation costs | 59 | 85 | 85 | 73 | 66 |
| Lease operating expenses | 117 | 217 | 217 | 193 | 197 |
| General and administrative expenses | 294 | 226 | 201 | 190 | 195 |
| Depreciation, depletion and amortization | 153 | 262 | 612 | 477 | 440 |
| Impairments/Ceiling test charges | — | 6 | 158 | 25 | 2,148 |
| Exploration expense | 105 | 249 | — | — | — |
| Taxes, other than income taxes | 57 | 91 | 91 | 85 | 68 |
| Total operating expenses | 785 | 1,136 | 1,364 | 1,058 | 3,145 |
| Operating income (loss) | 393 | 731 | 503 | 731 | (1,317) |
| Income (loss) from unconsolidated affiliates(2) | — | 5 | (7) | (7) | (30) |
| Other income (expense) | (2) | (2) | (2) | 3 | (1) |
| Interest expense, net of capitalized interest: |  |  |  |  |  |
| Third parties | (155) | (310) | (9) | (16) | (21) |
| Affiliates | — | — | (3) | (5) | (4) |
| Income (loss) before income taxes | 236 | 424 | 482 | 706 | (1,373) |
| Income tax expense (benefit) | 1 | (7) | 220 | 263 | (462) |
| Net income (loss) | $235 | $431 | $262 | $443 | $(911) |
| **Balance sheet data (at period end)** |  |  |  |  |  |
| Cash and cash equivalents | $41 |  | $25 | $74 | $183 |
| Total assets | 8,157 |  | 5,099 | 4,942 | 4,457 |
| Total debt | 4,243 |  | 851 | 301 | 835 |
| Members’/stockholder’s equity | 3,149 |  | 3,100 | 3,067 | 2,529 |
| **Statement of cash flows data** |  |  |  |  |  |
| Net cash provided by (used in): |  |  |  |  |  |
| Operating activities |  |  | $1,426 | $1,067 | $1,573 |
| Investing activities |  |  | (1,237) | (1,130) | (1,156) |
| Financing activities |  |  | (238) | (46) | (336) |
| **Other financial data** |  |  |  |  |  |
| Capital expenditures(3) | $762 |  | $1,644 | $1,318 | $1,129 |
| Adjusted EBITDAX(4) | 655 | 1,391 | 1,391 | 1,205 | 1,491 |
| Cash interest expense(5) | 147 | 313 |  |  |  |

(1) Includes $11 million, $11 million and $406 million for the years ended December 31, 2011, 2010 and 2009 and $5 million for the six months ended June 30, 2012, reclassified from accumulated other comprehensive income associated with accounting hedges. During 2008, we removed the hedging designation on all of our commodity‑based derivative contracts related to our hedged oil and natural gas production volumes.

(2) Income (loss) from unconsolidated affiliates includes equity earnings from Four Star Oil & Gas Company (“Four Star”), our unconsolidated affiliate, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets.

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

(4) The Adjusted EBITDAX measure presented in this prospectus is a non-GAAP measure and is not a measurement of operating performance computed in accordance with GAAP and should not be considered as a substitute for operating income, 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 further discussion in “Use of Non-GAAP Financial Information.”

The following table provides an unaudited reconciliation of net income to Adjusted EBITDAX:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **EP Energy LLC Pro forma** | | **EP Energy Corporation** | | |
|  | **Six Months** |  | **Historical** | | |
|  | **ended June 30,** | **Year ended December 31,** | **Year ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
|  | **(in millions)** | | | | |
| **Net income (loss)** | $235 | $431 | $262 | $443 | $(911) |
| Income tax expense (benefit) | 1 | (7) | 220 | 263 | (462) |
| Interest expense, net of capitalized interest | 155 | 310 | 12 | 21 | 25 |
| Depreciation, depletion and amortization | 153 | 262 | 612 | 477 | 440 |
| **Reported EBITDA** | 544 | 996 | 1,106 | 1,204 | (908) |
| Net impact of financial derivatives(a) | (214) | 47 | 47 | (92) | 323 |
| Impairments and ceiling test charges(b) | — | 100 | 158 | 25 | 2,148 |
| Transition and restructuring costs(c) | 183 | 6 | 6 | — | 7 |
| Dividends from unconsolidated affiliates(d) | 8 | 46 | 46 | 50 | 45 |
| Income (loss) from unconsolidated affiliates(e) | — | (5) | 7 | 7 | 30 |
| Non-cash equity‑based compensation expense(f) | 16 | 21 | 21 | 18 | 19 |
| Financial derivatives premiums(g) | — | — | — | (7) | (173) |
| Advisory fee(h) | 13 | 25 | — | — | — |
| Exploration expense(i) | 105 | 155 | — | — | — |
| **Adjusted EBITDAX(j)** | $655 | $1,391 | $1,391 | $1,205 | $1,491 |

(a) Represents the non-cash net change in the fair value of derivatives, net of actual cash settlements received/(paid) in respect of derivatives.

(b) Impairments and ceiling test charges include inventory impairments of $6 million in 2011 and $16 million in 2009.

(c) Reflects the transaction costs paid as part of the acquisition in 2012, a non‑recurring severance cost incurred in connection with the closure of our office in Denver in 2011 and a cost related to restructuring our organization in 2009.

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

(e) 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.

(f) Represents non-cash equity‑based compensation expense.

(g) Represents the net cash outflows related to premiums paid on the derivative contracts.

(h) Represents the pro‑rata portion of the annual advisory fee to be paid to affiliates of the Sponsors and other investors. The annual advisory fee is $25 million.

(i) Represents exploration expense recorded due to applying the successful efforts method of accounting following the acquisition.

(j) Includes net EBITDAX contribution of $31 million, $136 million, $136 million, $203 million and $206 million for each period, related to business divestitures including the divestiture of Gulf of Mexico in July 2012, the divestitures of our Blue Creek West, Minden and Powder River operations in 2011 and the divestitures of our Catapult operations and Altamont processing plant and related gathering systems in 2010.

(5) Represents cash interest expense for the six months ended June 30, 2012 and the year ended December 31, 2011, in each case calculated on a pro forma basis after giving effect to the Acquisition and Refinancing Transactions.

**Summary Operating and Reserve Information**

**Proved Reserves**

The proved reserve estimates set forth below are for the Acquired Business and were prepared in accordance with SEC rules using the first day 12-month average price as of December 31, 2011.

The following table summarizes our historical proved reserves and related PV-10 as of the dates indicated. The proved reserves as of December 31, 2011 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 December 31, 2011. 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 Company, L.P. (“Ryder Scott”) conducted an audit of the estimates of the proved reserves prepared by us as of December 31, 2011. In connection with its audit, Ryder Scott reviewed 86% of the properties associated with our proved reserves on a natural gas equivalent basis, representing 87% 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, 2011. In connection with the audit of these proved reserves, Ryder Scott reviewed 87% of the properties associated with Four Star’s total proved reserves on a natural gas equivalent basis, representing 91% of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates, in the aggregate, are within 10% of Ryder Scott’s estimates.

|  |  |
| --- | --- |
|  | **As of December 31, 2011** |
| **Proved reserves(1):** |  |
| Natural gas (MMcf) | 2,781,904 |
| Oil/Condensate (MBbls) | 181,639 |
| NGL (MBbls) | 19,153 |
| Total estimated net proved reserves (MMcfe) | 3,986,658 |
| Proved developed producing (MMcfe) | 1,694,039 |
| Proved developed non-producing (MMcfe) | 350,274 |
| Proved undeveloped (MMcfe) | 1,942,345 |
| Percent proved developed reserves (%) | 51% |
| PV-10 (in thousands)(2) | $7,015,973 |

(1) Includes the net proved reserve amounts represented by our approximate 49% equity interest in Four Star. Specifically, net proved reserves represented by our approximate 49% interest in Four Star as of December 31, 2011 were 134,713 MMcf natural gas, 1,569 MBbls oil and condensate and 4,908 MBbls NGL, totaling 173,574 MMcfe total net proved reserves. Total net proved reserves were comprised of 144,248 MMcfe proved developed producing, 5,292 MMcfe proved developed non-producing, and 24,034 MMcfe proved undeveloped.

(2) PV-10 is considered 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. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10%. 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 NGL 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 NGL 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 average of the historical first‑day‑of‑the‑month prices for the prior 12 months was $4.12 per MMBtu of natural gas and $96.19 per barrel of oil as of December 31, 2011.

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

|  |  |
| --- | --- |
|  | **As of December 31, 2011** |
| PV-10 | $7,016 |
| Income taxes, discounted at 10% | (1,816) |
| Discounting difference(a) | 210 |
| Standardized measure of discounted future net cash flows | $5,410 |

(a) Discounting difference relates to differences in the manner in which discounted cash flows are determined for reserve calculations (monthly) versus the discount calculation for purposes of calculating the standardized measure (annually).

**Production, Revenues and Price History**

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

|  |  |  |  |
| --- | --- | --- | --- |
|  | **EP Energy Corporation Historical** | | |
|  | **Year ended December 31,** | | |
|  | **2011** | **2010** | **2009** |
| **Production data(1):** |  |  |  |
| Natural gas (MMcf) | 257,964 | 242,776 | 238,101 |
| Oil/Condensate (MBbls) | 6,340 | 5,111 | 4,497 |
| NGL (MBbls) | 1,624 | 1,996 | 2,248 |
| Combined production (MMcfe) | 305,748 | 285,418 | 278,571 |
| Average combined daily production (MMcfe/d) | 838 | 782 | 763 |
| **Average realized prices on physical sales(2):** |  |  |  |
| Natural gas (Mcf) | $4.04 | $4.32 | $3.80 |
| Oil (Bbl) | 91.40 | 72.83 | 52.48 |
| NGL (Bbl) | 53.50 | 42.38 | 33.75 |
| **Average realized prices, including financial derivative settlements(2)(3):** |  |  |  |
| Natural gas (Mcf) | $5.44 | $5.67 | $7.62 |
| Oil (Bbl) | 90.23 | 71.13 | 95.57 |
| NGL (Bbl) | 53.50 | 42.38 | 33.75 |
| **Average cash operating cost per Mcfe(4):** |  |  |  |
| Lease operating expenses(5) | $0.77 | $0.73 | $0.78 |
| Production taxes | 0.28 | 0.27 | 0.22 |
| General and administrative expenses | 0.70 | 0.72 | 0.77 |
| Taxes other than production and income taxes | 0.04 | 0.06 | 0.05 |
| Total | $1.79 | $1.78 | $1.82 |
| Depreciation, depletion and amortization | $2.16 | $1.82 | $1.74 |

(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 as of December 31, 2011 were 16,881 MMcf natural gas, 306 MBbls oil and condensate, 556 MBbls NGL, 22,052 MMcfe combined production and 61 MMcfe/d average combined daily production.

(2) Average prices shown in the table reflect prices both before and after the effects of financial derivative settlements.

(3) We had no cash premiums related to oil derivatives settled during the years ended December 31, 2011, 2010 and 2009. Premiums paid related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Premiums paid related to natural gas derivatives settled during the year ended December 31, 2011 were $23 million. Had we included these premiums in our natural gas average realized prices in 2011 and 2010, our realized price, including financial derivatives settlements, would have decreased by $0.10 per Mcf and $0.70 per Mcf for the years ended December 31, 2011 and 2010.

(4) Total adjusted cash operating costs per unit for each period were $1.69/Mcfe, $1.71/Mcfe and $1.72/Mcfe.

(5) Includes approximately $14 million of start-up costs in Camarupim Field in 2009 or $3.08 per Mcfe for Brazil and $0.05 per Mcfe worldwide.

**RISK FACTORS**

*Investing in the exchange notes in this exchange offer involves a high degree of risk. You should carefully consider the risk factors set forth below, as well as the other information contained in this prospectus, before participating in the exchange offer. Any of the following risks could materially and adversely affect our business, financial condition or results of operations. In addition, the risks described below are not the only risks that we face. Additional risks and uncertainties not currently known to us or those that we currently view to be immaterial could also materially and adversely affect our business, financial condition or results of operations. In any such case, you may lose all or a part of your original investment.*

**Risks Related to the Exchange Offer**

***If you do not properly tender your initial notes, you will continue to hold unregistered initial notes and be subject to the same limitations on your ability to transfer initial notes.***

We will only issue exchange notes in exchange for initial notes that are timely received by the exchange agent together with all required documents, including a properly completed and signed letter of transmittal. Therefore, you should allow sufficient time to ensure timely delivery of the initial notes and you should carefully follow the instructions on how to tender your initial notes. Neither we nor the exchange agent are required to tell you of any defects or irregularities with respect to your tender of the initial notes. If you are eligible to participate in the exchange offer and do not tender your initial notes or if we do not accept your initial notes because you did not tender your initial notes properly, then, after we consummate the exchange offer, you will continue to hold initial notes that are subject to the existing transfer restrictions and will no longer have any registration rights or be entitled to any additional interest with respect to the initial notes. In addition:

• if you tender your initial notes for the purpose of participating in a distribution of the exchange notes, you will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale of the exchange notes; and

• if you are a broker‑dealer that receives exchange notes for your own account in exchange for initial notes that you acquired as a result of market‑making activities or any other trading activities, you will be required to acknowledge that you (i) have not entered into any arrangement or understanding with the Issuers or an affiliate of the Issuers to distribute those exchange notes and (ii) will deliver a prospectus in connection with any resale of those exchange notes.

We have agreed that, for a period of 180 days after the exchange offer is consummated, we will make this prospectus available to any broker‑dealer for use in connection with any resales of the exchange notes.

After the exchange offer is consummated, if you continue to hold any initial notes, you may have difficulty selling them because there will be fewer initial notes outstanding.

***The issuance of the exchange notes may adversely affect the market for the initial notes.***

To the extent the initial notes are tendered and accepted in the exchange offer, the trading market for the untendered and tendered but unaccepted initial notes could be adversely affected. Because we anticipate that most holders of the initial notes will elect to exchange their initial notes for exchange notes due to the absence of restrictions on the resale of exchange notes under the Securities Act, we anticipate that the liquidity of the market for any initial notes remaining after the completion of this exchange offer may be substantially limited. Please refer to the section in this prospectus entitled “The Exchange Offer—Your Failure to Participate in the Exchange Offer Will Have Adverse Consequences.”

***Some persons who participate in the exchange offer must deliver a prospectus in connection with resales of the exchange notes.***

Based on interpretations of the staff of the SEC contained in Exxon Capital Holdings Corp., SEC no-action letter (April 13, 1988), Morgan Stanley & Co. Inc., SEC no-action letter (June 5, 1991) and Shearman & Sterling, SEC no-action letter (July 2, 1983), we believe that you may offer for resale, resell or otherwise transfer the exchange notes without compliance with the registration and prospectus delivery requirements of the Securities Act. However, in some instances described in this prospectus under “Plan of Distribution,” you will remain obligated to comply with the registration and prospectus delivery requirements of the Securities Act to transfer your exchange notes. In these cases, if you transfer any exchange note without delivering a prospectus meeting the requirements of the Securities Act or without an exemption from registration of your exchange notes under the Securities Act, you may incur liability under the Securities Act. We do not and will not assume, or indemnify you against, this liability.

**Risks Related to Our Indebtedness and the Notes**

***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 on the notes.***

After giving pro forma effect to the Acquisition Transactions and the Refinancing Transactions, we are a highly leveraged company. As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, we would have had $4,250 million face value of outstanding indebtedness (in addition to approximately $1.5 billion of undrawn commitments under the RBL Facility), and for the six months ended June 30, 2012, we would have had total pro forma debt service payment obligations of $156 million.

Our substantial indebtedness could have important consequences for you as a holder of the notes. 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, including the notes, 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 indentures governing the notes and the agreements governing other 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;

• prevent us from raising the funds necessary to repurchase all notes tendered to us upon the occurrence of certain changes of control, which failure to repurchase would constitute a default under the indentures governing the notes; or

• expose us to the risk of increased interest rates, as certain of our borrowings, including borrowings under the RBL Facility and the senior secured term loan, are at variable rates of interest.

In addition, the credit agreements governing the RBL Facility and our new senior secured term loan and the indentures governing the notes contain restrictive covenants that will 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.

***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 indentures governing the notes and the credit agreements governing the RBL Facility and the senior secured term loan contain restrictions on our and our subsidiaries’ ability to incur additional indebtedness, including secured indebtedness that will be effectively senior to the senior notes and could be effectively senior to the senior secured notes, 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. As of June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, we would have had approximately $1.5 billion available for additional borrowing under the RBL Facility, all of which would be secured. In addition to the notes and our borrowings under the RBL Facility and the senior secured term loan, 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 securityholders, 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 on the notes.”

***We may not be able to generate sufficient cash to service all of our indebtedness, including the notes, 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 the notes and to satisfy our other debt obligations will depend upon, among other things:

• our future financial and operating performance (including the realization of any cost savings described herein), 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, the availability of which depends on, among other things, our complying 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 the notes.

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, including the notes. 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, including the RBL Facility, the senior secured term loan and the indentures governing the notes, may restrict us from adopting some of these alternatives. In the absence of such operating results and resources, we could face substantial liquidity problems and might be 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 the notes.

If we cannot make scheduled payments on our indebtedness, we will be in default and holders of the notes could declare all outstanding principal and interest to be due and payable, the lenders under the RBL Facility could terminate their commitments to loan money, our secured lenders (including the lenders under the RBL Facility and the senior secured term loan and the holders of the senior secured notes) could foreclose against the assets securing their loans and the senior secured notes and we could be forced into bankruptcy or liquidation. All of these events could cause you to lose all or part of your investment in the notes.

***Repayment of our debt, including the notes, is dependent on cash flow generated by our subsidiaries.***

We are a holding company and have no direct operations other than holding the equity interests in our subsidiaries and activities directly related thereto. Accordingly, repayment of our indebtedness, including the notes, is dependent on the generation of cash flow by our subsidiaries and (if they are not guarantors of the notes) their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are guarantors of the notes, our subsidiaries do not have any obligation to pay amounts due on the notes or to make funds available for that purpose. Our subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness, including the notes. Each of our subsidiaries is a distinct legal entity, and under certain circumstances legal and contractual restrictions may limit our ability to obtain cash from them and we may be limited in our ability to cause any future joint ventures to distribute their earnings to us. While the indentures governing the notes and the credit agreements governing the RBL Facility and the senior secured term loan limit the ability of our subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations are subject to certain qualifications and exceptions. In the event that we do not receive distributions from our non-guarantor subsidiaries, we may be unable to make required principal and interest payments on our indebtedness, including the notes.

***If we default on our obligations to pay our other indebtedness, we may not be able to make payments on the notes.***

Any default under the agreements governing our indebtedness, including defaults under the RBL Facility and the senior secured term loan that are not waived by the required lenders, and the remedies sought by the holders of such indebtedness could leave us unable to pay principal, premium, if any, or interest on the notes and could substantially decrease the market value of the notes. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, or interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness (including the RBL Facility and the senior secured term loan), we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to (i) declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, (ii) terminate their commitments and cease making further loans and (iii) institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to seek waivers from the required lenders or holders under the RBL Facility, the senior secured term loan and the notes to avoid being in default. If we breach our covenants under the RBL Facility, the senior secured term loan and the notes and seek a waiver, we may not be able to obtain a waiver from the required lenders or holders, as applicable. If this occurs, we would be in default under these facilities, the lenders or holders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. See “Description of Other Indebtedness,” “Description of Senior 2020 Exchange Notes,” “Description of Senior 2022 Exchange Notes” and “Description of Senior Secured Exchange Notes.”

Upon any such bankruptcy filing, we would be stayed from making any ongoing payments on the notes, and the holders of the notes would not be entitled to receive post-petition interest or applicable fees, costs or charges, or any “adequate protection” under Title 11 of the United States Code, as amended (the “Bankruptcy Code”).

***The notes will be structurally subordinated to all liabilities of our non-guarantor subsidiaries.***

The notes will be structurally subordinated to indebtedness and other liabilities of our subsidiaries that are not guaranteeing the notes, and the claims of creditors of these subsidiaries, including trade creditors, will have priority as to the assets of these subsidiaries. In the event of a bankruptcy, liquidation or reorganization of any of our non-guarantor subsidiaries, these non-guarantor subsidiaries will pay the holders of their debts, holders of preferred equity interests and their trade creditors before they will be able to distribute any of their assets to us. During the six months ended June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, these non-guarantor subsidiaries generated approximately 5% of our total revenue and 2% of our Adjusted EBITDAX. As of June 30, 2012, on a pro forma basis these non-guarantor subsidiaries held approximately 2% of our consolidated assets and had no outstanding indebtedness, excluding intercompany obligations.

In addition, the indentures governing the notes permit these subsidiaries to incur additional indebtedness, subject to some limitations, and do not contain any limitation on the amount of other liabilities, such as trade payables, that may be incurred by these subsidiaries.

The notes will not be guaranteed by any of our non-U.S. subsidiaries or any other subsidiaries that are not material or wholly owned. These non-guarantor subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay any amounts due pursuant to the notes, or to make any funds available therefore, whether by dividends, loans, distributions or other payments. Any right that we or the subsidiary guarantors have to receive any assets of any of the non-guarantor subsidiaries upon the liquidation or reorganization of those subsidiaries, and the consequent rights of holders of notes to realize proceeds from the sale of any of those subsidiaries’ assets, will be effectively subordinated to the claims of those subsidiaries’ creditors, including trade creditors and holders of preferred equity interests of those subsidiaries.

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

The RBL Facility, the senior secured term loan and the indentures governing the notes contain, and any other existing or future indebtedness of ours would likely contain, a number of covenants that will 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 Other 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, the senior secured term loan, the notes or any of our other future 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;

• could require us to apply all of our available cash to repay these borrowings; or

• could effectively prevent us from making debt service payments on the notes (due to a cash sweep feature);

any of which could result in an event of default under the notes.

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, the senior secured term loan and the notes 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, the senior secured term loan and the senior secured notes.

If any of our outstanding indebtedness under the RBL Facility, the senior secured term loan or our other indebtedness, including the notes, were to be accelerated, there can be no assurance that our assets would be sufficient to repay such indebtedness in full. See “Description of Other Indebtedness,” “Description of Senior 2020 Exchange Notes,” “Description of Senior 2022 Exchange Notes” and “Description of Senior Secured Exchange Notes.”

***Because each subsidiary guarantor’s liability under its guarantee may be reduced to zero, avoided or released under certain circumstances, you may not receive any payments from some or all of the subsidiary guarantors.***

You have the benefit of the guarantees of the guarantors. However, the guarantees by the subsidiary guarantors are limited to the maximum amount that such guarantors are permitted to guarantee under applicable law. As a result, any such guarantor’s liability under its guarantee could be reduced to zero, depending on the amount of other obligations of such guarantor. Further, under the circumstances discussed more fully below, a court under federal or state fraudulent conveyance and transfer statutes could void the obligations under a guarantee or further subordinate it to all other obligations of the guarantor.

In addition, the subsidiary guarantors will be automatically released from their guarantees upon the occurrence of certain events, including the following:

• the designation of a subsidiary guarantor as an unrestricted subsidiary;

• the release or discharge of any guarantee or indebtedness that resulted in the creation of the guarantee of the notes by a subsidiary guarantor; or

• the sale or other disposition, including the sale of substantially all the assets, of a subsidiary guarantor.

If the guarantee of any subsidiary guarantor is released, no holder of the notes will have a claim as a creditor against that subsidiary, and the indebtedness and other liabilities, including trade payables and preferred stock, if any, whether secured or unsecured, of that subsidiary will be structurally senior to the claim of any holders of the notes. See “Description of Senior 2020 Exchange Notes—Subsidiary Guarantees,” “Description of Senior 2022 Exchange Notes—Subsidiary Guarantees” and “Description of Senior Secured Exchange Notes—Subsidiary Guarantees.”

***We may not be able to repurchase the notes upon a change of control.***

Upon the occurrence of certain specific kinds of change of control events, we will be required to offer to repurchase all outstanding notes and our senior secured term loan at 101% of the principal amount thereof plus, without duplication, accrued and unpaid interest and additional interest, if any, to the date of repurchase. Additionally, under the RBL Facility, a change of control constitutes an event of default that permits the lenders to accelerate the maturity of borrowings and terminate their commitments to lend. The source of funds for any repurchase of the notes and repayment of borrowings under the RBL Facility and the senior secured term loan would be our available cash or cash generated from our subsidiaries’ operations or other sources, including borrowings, sales of assets or sales of equity. It is possible that we will not have sufficient funds at the time of a change of control to make the required repurchase of notes or that restrictions in the RBL Facility and the senior secured term loan will not allow such repurchases. We may require additional financing from third parties to fund any such repurchases, and we may be unable to obtain financing on satisfactory terms or at all. Further, our ability to repurchase the notes may be limited by law. In addition, certain important corporate events, such as leveraged recapitalizations that would increase the level of our indebtedness, would not constitute a change of control under the indentures governing the notes. See “Description of Senior 2020 Exchange Notes—Change of Control,” “Description of Senior 2022 Exchange Notes—Change of Control” and “Description of Senior Secured Exchange Notes—Change of Control.”

Courts interpreting change of control provisions under New York law (which will be the governing law of the indentures governing the notes) have not provided clear and consistent meanings of such change of control provisions which leads to subjective judicial interpretation. In addition, a court case in Delaware has questioned whether a change of control provision contained in an indenture could be unenforceable on public policy grounds.

***We may enter into transactions that would not constitute a change of control that could affect our ability to satisfy our obligations under the notes.***

Legal uncertainty regarding what constitutes a change of control and the provisions of the indentures governing the notes may allow us to enter into transactions, such as acquisitions, refinancing or recapitalizations, that would not constitute a change of control but may increase our outstanding indebtedness or otherwise affect our ability to satisfy our obligations under the notes. The definition of change of control for purposes of the notes includes a phrase relating to the transfer of “all or substantially all” of our assets taken as a whole. Although there is a limited body of case law interpreting the phrase “substantially all,” there is no precise established definition of the phrase under applicable law. Accordingly, your ability to require us to repurchase notes as a result of a transfer of less than all of our assets to another person may be uncertain.

***Federal and state statutes allow courts, under specific circumstances, to void notes and guarantees and require noteholders to return payments received.***

If we or any guarantor becomes a debtor in a case under the Bankruptcy Code or encounters other financial difficulty, under federal or state fraudulent transfer law a court may void or otherwise decline to enforce the notes or the guarantees. A court might do so if it found that when we issued the notes or the subsidiary guarantor entered into its guarantee, or in some states when payments became due under the notes or the guarantees, we or the subsidiary guarantor received less than reasonably equivalent value or fair consideration and:

• was insolvent or rendered insolvent by reason of such incurrence;

• was left with inadequate capital to conduct its business;

• believed or reasonably should have believed that it would incur debts beyond its ability to pay; or

• was a defendant in an action for money damages or had a judgment for money damages docketed against us or the subsidiary guarantor if, in either case, the judgment is unsatisfied after final judgment.

The court might also void an issuance of notes or a guarantee, without regard to the above factors, if the court found that we issued the notes or the applicable guarantor entered into its guarantee with actual intent to hinder, delay or defraud its creditors.

A court would likely find that we or a guarantor did not receive reasonably equivalent value or fair consideration for the notes or its guarantee if we or a guarantor did not substantially benefit directly or indirectly from the issuance of the notes. If a court were to void the issuance of the notes or any guarantee you would no longer have any claim against the issuer or the applicable guarantor. Sufficient funds to repay the notes may not be available from other sources, including the remaining obligors, if any. In addition, the court might direct you to repay any amounts that you already received from us or a guarantor. In the event of a finding that a fraudulent transfer or conveyance occurred, you may not receive any repayment on the notes. Further, the avoidance of the notes could result in an event of default with respect to our and our subsidiaries’ other debt, which could result in acceleration of that debt.

The measures of insolvency for purposes of these fraudulent transfer laws will vary depending upon the law applied in any proceeding to determine whether a fraudulent transfer has occurred. Generally, however, a guarantor would be considered insolvent if:

• the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all of its assets;

• if the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or

• it could not pay its debts as they become due.

On the basis of historical financial information, recent operating history and other factors, we believe that each subsidiary guarantor, after giving effect to its guarantee of these notes, will not be insolvent, will not have unreasonably small capital for the business in which it is engaged and will not have incurred debts beyond its ability to pay such debts as they mature. In addition, no subsidiary guarantor was a defendant in an action for money damages, or had a judgment for money damages docketed against it, for which the judgment was unsatisfied after final judgment. We cannot assure you, however, as to what standard a court would apply in making these determinations or that a court would agree with our conclusions in this regard.

Although each guarantee entered into by a guarantor will contain a provision intended to limit that guarantor’s liability to the maximum amount that it could incur without causing the incurrence of obligations under its guarantee to be a fraudulent transfer, this provision may not be effective to protect those guarantees from being voided under fraudulent transfer law, or may reduce that guarantor’s obligation to an amount that effectively makes its guarantee worthless.

Finally, as a court of equity, the bankruptcy court may subordinate the claims in respect of the notes to other claims against us under the principle of equitable subordination if the court determines that (a) the holder of notes engaged in some type of inequitable conduct, (b) the inequitable conduct resulted in injury to our other creditors or conferred an unfair advantage upon the holders of notes and (c) equitable subordination is not inconsistent with the provisions of the Bankruptcy Code.

***Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.***

Borrowings under the RBL Facility and the senior secured term loan are at variable rates of interest and expose us to interest rate risk. Assuming the RBL Facility is fully drawn and the applicable LIBOR rate exceeds the term loan LIBOR floor, each 0.125% change in assumed blended interest rates would result in a $3.4 million change in annual interest expense on indebtedness under the RBL Facility and the senior secured term loan. In the future, we may enter into interest rate swaps that involve the exchange of floating for fixed rate interest payments in order to reduce interest rate volatility. However, we may not maintain interest rate swaps with respect to all of our variable rate indebtedness, and any swaps we enter into may not fully mitigate our interest rate risk, may prove disadvantageous or may create additional risks.

***Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop, or if developed be maintained, for the notes.***

The notes are new issues of securities for which there is no established public market. We do not intend to have the notes listed on a national securities exchange or included in any automated quotation system. Affiliates of the initial purchasers of the initial notes have advised us that they intend to make a market in the notes, as permitted by applicable laws and regulations; however, they are not obligated to make a market in any of the notes, and they may discontinue their market making activities at any time without notice. Therefore, an active market for any of the notes may not develop or, if developed, it may not continue. The liquidity of any market for the notes will depend upon the number of holders of the notes, our performance, the market for similar securities, the interest of securities dealers in making a market in the notes and other factors. A liquid trading market may not develop for the notes or any series of notes. If an active market does not develop or is not maintained, the price and liquidity of the notes may be adversely affected. Historically, the market for non‑investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. The market, if any, for any of the notes may not be free from similar disruptions and any such disruptions may adversely affect the prices at which you may sell your notes. In addition, the notes may trade at a discount from their value on the date you acquired the notes, depending upon prevailing interest rates, the market for similar notes, our performance and other factors.

***Many of the restrictive covenants contained in the indentures governing the notes will not apply during any period in which the notes are rated investment grade by both Moody’s and S&P.***

Many of the covenants contained in the indentures governing the notes will not apply to us during any period in which the notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Group, provided that at such time no default or event of default has occurred and is continuing. Such covenants will include restrictions on, among other things, our ability to make certain distributions, incur indebtedness and enter into certain other transactions. There can be no assurance that the notes will ever be rated investment grade or that if the notes ever are rated investment grade they will maintain these ratings. However, suspension of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. To the extent the covenants are subsequently reinstated, any such actions taken while the covenants were suspended would not result in an event of default under the indentures governing the notes. See “Description of Senior 2020 Exchange Notes—Certain Covenants,” “Description of Senior 2022 Exchange Notes—Certain Covenants” and “Description of Senior Secured Exchange Notes—Certain Covenants.”

**Additional Risks Related to the Senior Secured Notes**

***The lien on the RBL Facility Priority Collateral securing the senior secured notes and the guarantees is junior and subordinate to the lien on the RBL Facility Priority Collateral securing the RBL Facility and certain other first lien obligations.***

The senior secured notes and related guarantees will be secured by second‑priority liens on the RBL Facility Priority Collateral, which secures on a first‑priority basis obligations under our the RBL Facility and certain hedging and cash management obligations, subject to certain permitted liens, exceptions and encumbrances described in the indenture governing the senior secured notes and the security documents relating to the senior secured notes. As set out in more detail under “Description of Senior Secured Exchange Notes—Security,” the lenders under the RBL Facility and holders of certain of our hedging and cash management obligations will be entitled to receive all proceeds from the realization of the RBL Facility Priority Collateral before the notes under certain circumstances, including upon default in payment on, or the acceleration of, any obligations under the RBL Facility, or in the event of our or any guarantor’s bankruptcy, insolvency, liquidation, dissolution, reorganization or similar proceeding, to repay such obligations in full before the holders of the senior secured notes will be entitled to any recovery from the RBL Facility Priority Collateral. In addition, the indenture governing the senior secured notes will permit us and the guarantors to create additional liens under specified circumstances, including liens senior in priority to the liens on the RBL Facility Priority Collateral securing the senior secured notes. Any obligations secured by such liens may further limit the recovery from the realization of the RBL Facility Priority Collateral available to satisfy holders of the senior secured notes.

***Holders of the senior secured notes will not control decisions regarding the RBL Facility Priority Collateral.***

The lenders under the RBL Facility, as holders of first priority-lien obligations, will control substantially all matters related to the RBL Facility Priority Collateral pursuant to the terms of the senior lien intercreditor agreement. The holders of the first‑priority lien obligations may cause the collateral agent thereunder (the “first lien agent”) to dispose of, release or foreclose on, or take other actions with respect to, the RBL Facility Priority Collateral (including amendments of and waivers under the security documents) with which holders of the senior secured notes may disagree or that may be contrary to the interests of holders of the senior secured notes, even after a default under the senior secured notes. To the extent RBL Facility Priority Collateral is released from securing the first‑priority lien obligations, the senior lien intercreditor agreement will provide that, in certain circumstances, the second‑priority liens securing the senior secured notes will also be released. In addition, the security documents related to the second‑priority liens generally will provide that, so long as the first‑priority lien obligations are in effect, the holders of the first‑priority lien obligations may change, waive, modify or vary the security documents governing such first‑priority liens without the consent of the holders of the senior secured notes (except under certain limited circumstances) and that the security documents governing the second‑priority liens will be automatically be changed, waived and modified in the same manner. Further, the security documents governing the second‑priority liens may not be amended in any manner adverse to the holders of the first‑priority obligations without the consent of the first lien agent until the first priority lien obligations are paid in full. The security agreement governing the second‑priority liens will prohibit second‑priority lienholders from foreclosing on the RBL Facility Priority Collateral until payment in full of the first‑priority lien obligations. We cannot assure you that in the event of a foreclosure by the holders of the first‑priority lien obligations, the proceeds from the sale of collateral would be sufficient to satisfy all or any of the amounts outstanding under the senior secured notes after payment in full of the obligations secured by first‑priority liens on the RBL Facility Priority Collateral. If such proceeds were not sufficient to repay amounts outstanding under the senior secured notes and the senior secured term loan, then holders of the senior secured notes (to the extent not repaid from the proceeds of the sale of the RBL Facility Priority Collateral and Secured Notes/Term Loan Priority Collateral) would only have an unsecured claim against our remaining assets, which claim will rank equal in priority to the unsecured claims with respect to any unsatisfied portion of the obligations secured by the first‑priority liens or other second‑priority liens and our other unsecured senior indebtedness (including the senior notes). See also “Description of Senior Secured Exchange Notes—Security—Intercreditor Agreements—Senior Lien Intercreditor Agreement.”

***Security interest in certain of the collateral may not be in place on the date of the consummation of the exchange offer for the senior secured notes.***

Security interests may not be in place on the date of the consummation of the exchange offer for the senior secured notes. We are required to deliver real property mortgages only on certain oil and gas properties encumbering (x) not less than 50% of the PV-10 value of the proved oil and gas reserves included in the borrowing base under the RBL Facility no later than 90 days following the Acquisition and (y) 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 no later than 120 days following the Acquisition, subject to extensions that may be granted in the discretion of the administrative agent under the RBL Facility. Any issues that we are not able to resolve in connection with the delivery and recordation of such mortgages and security interests may negatively impact the value of the collateral. To the extent a security interest in certain collateral is perfected following the date of issuance of the senior secured notes, it might be avoidable in bankruptcy. See “—Any future pledge of collateral might be avoidable in bankruptcy.”

***The capital stock of each of our subsidiaries that has been pledged to secure the senior secured notes will be automatically released from the collateral for the senior secured notes to the extent that the pledge would require the preparation and filing of separate audited financial statements of such subsidiary under Rule 3-16 of Regulation S-X under the Securities Act.***

Pursuant to the terms of the indenture governing the senior secured notes, a portion (or, if necessary, all) of the capital stock of each of our subsidiaries that has been pledged to secure the senior secured notes will be automatically released from the collateral for the senior secured notes to the extent that the pledge would require the preparation and filing of separate audited financial statements of such subsidiary under Rule 3-16 of Regulation S-X under the Securities Act. As a result, the collateral securing the senior secured notes will include the capital stock of each such subsidiary only to the extent that the applicable value of such capital stock (on a subsidiary-by-subsidiary basis) is less than 20% of the aggregate principal amount of the outstanding notes. See “Description of Senior Secured Exchange Notes—Security—Limitations on Stock Collateral.” The senior secured term loan will be subject to the same limits described herein.

***It may be difficult to realize the value of the collateral securing the senior secured notes.***

The collateral securing the senior secured notes will be subject to any and all exceptions, defects, encumbrances, liens and other imperfections as may be accepted by the trustee for the senior secured notes and the collateral agent thereunder (the “second lien collateral agent”) and any other creditors that have the benefit of first‑priority liens on the collateral securing the senior secured notes from time to time, whether on or after the date the senior secured notes are issued. The existence of any such exceptions, defects, encumbrances, liens and other imperfections could adversely affect the value of the collateral securing the senior secured notes as well as the ability of the second lien collateral agent to realize or foreclose on such collateral.

The value of the collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers. By their nature, some or all of the pledged assets may be illiquid and may have no readily ascertainable market value. We cannot assure you that the fair market value of the collateral as of the date of this prospectus exceeds the principal amount of the debt secured thereby. The value of the assets pledged as collateral for the senior secured notes could be impaired in the future as a result of changing economic conditions, our failure to implement our business strategy, competition, unforeseen liabilities and other future events. Accordingly, there may not be sufficient collateral to pay all or any of the amounts due on the senior secured notes. Any claim for the difference between the amount, if any, realized by holders of the senior secured notes from the sale of the collateral securing the senior secured notes and the obligations under the senior secured notes will rank equally in right of payment with all of our other unsecured unsubordinated indebtedness and other obligations, including trade payables. Additionally, in the event that a bankruptcy case is commenced by or against us, if the value of the collateral is less than the amount of principal and accrued and unpaid interest on the senior secured notes and all other senior secured obligations, interest may cease to accrue on the senior secured notes from and after the date the bankruptcy petition is filed.

In the future, the obligation to grant additional security over assets, or a particular type or class of assets, whether as a result of the acquisition or creation of future assets or subsidiaries, the designation of a previously unrestricted subsidiary or otherwise, is subject to the provisions of the intercreditor agreement. The intercreditor agreement sets out a number of limitations on the rights of the holders of the senior secured notes offered hereby to require security in certain circumstances, which may result in, among other things, the amount recoverable under any security provided by any subsidiary being limited and/or security not being granted over a particular type or class of assets. Accordingly, this may affect the value of the security provided by us and our subsidiaries. Furthermore, upon enforcement against any collateral or in insolvency, under the terms of the intercreditor agreement the claims of the holders of the senior secured notes offered hereby to the proceeds of such enforcement will rank behind the claims of the holders of obligations under the RBL facility, which are first‑priority obligations, and holders of additional secured indebtedness (to the extent permitted to have priority by the indenture governing the senior secured notes).

The security interest of the second lien collateral agent will be subject to practical problems generally associated with the realization of security interests in collateral. For example, the second lien collateral agent may need to obtain the consent of a third party to obtain or enforce a security interest in a contract. We cannot assure you that the second lien collateral agent will be able to obtain any such consent. We also cannot assure you that the consents of any third parties will be given when required to facilitate a foreclosure on such assets. Accordingly, the second lien collateral agent may not have the ability to foreclose upon those assets and the value of the collateral may significantly decrease.

***The value of the Secured Notes/Term Loan Priority Collateral will not be sufficient to repay the obligations under the senior secured notes and senior secured term loan.***

The Secured Notes/Term Loan Priority Collateral is composed of 65% of the voting capital stock and 100% of the non-voting capital stock of all first-tier foreign subsidiaries of the Issuers and each of the guarantors. These foreign subsidiaries constitute approximately 2% of our consolidated assets and generated approximately 5% of our revenue and 2% of our Adjusted EBITDAX as of June 30, 2012 on a pro forma basis after giving effect to the Refinancing Transactions. In addition, the Secured Notes/Term Loan Priority Collateral will also secure our obligations under our new senior secured term loan on a first lien basis pari passu with the senior secured notes. No appraisals of any collateral have been prepared in connection with the offering of the senior secured notes. The value of the collateral securing the senior secured notes will depend on market and other economic conditions, including the availability of suitable buyers for the collateral. Accordingly, the value of the Secured Notes/Term Loan Priority Collateral will not be sufficient to repay any obligations under the senior secured notes and senior secured term loan, and holders of the senior secured notes would only have rights to their second‑priority interest on the RBL Facility Priority Collateral and, to the extent such collateral is insufficient, would have an unsecured claim against our remaining assets, ranking equal to other unsecured claims.

***Rights in the collateral may be adversely affected by the failure to perfect securities interests in collateral.***

Applicable law provides that a security interest in certain tangible and intangible assets can only be properly perfected and its priority retained through certain actions undertaken by the secured party. The liens in the collateral securing the senior secured notes may not be perfected with respect to the claims of such senior secured notes if the collateral agent for the senior secured notes is not able to take the actions necessary to perfect any of these liens on or prior to the date of the indenture governing such senior secured notes. In addition, applicable law provides that certain property and rights acquired after the grant of a general security interest, such as real property, equipment subject to a certificate and certain proceeds, can only be perfected at the time such property and rights are acquired and identified. We and the guarantors have limited obligations to perfect the senior secured noteholders’ security interest in specified collateral. The collateral agent for the senior secured notes will not monitor, and there can be no assurance that we will inform the collateral agent of, the future acquisition of property and rights that constitute collateral, and that the necessary action will be taken to properly perfect the security interest in such after‑acquired collateral. The collateral agent for the senior secured notes has no obligation to monitor the acquisition of additional property or rights that constitute collateral or the perfection of any security interest. Such failure may result in the loss of the security interest in the collateral or the priority of the security interest in favor of the collateral agent for the senior secured notes, as applicable, against third parties. The collateral agent for the senior secured notes will be the collateral agent under our new senior secured term loan.

***Bankruptcy laws may limit your ability to realize value from the collateral.***

The right of the second lien collateral agent to repossess and dispose of the collateral upon the occurrence of an event of default under the indenture governing the senior secured notes is likely to be significantly impaired by applicable bankruptcy law if a bankruptcy case were to be commenced by or against us before the second lien collateral agent repossessed and disposed of the collateral. Upon the commencement of a case under the bankruptcy code, a secured creditor such as the second lien collateral agent is prohibited from repossessing its security from a debtor in a bankruptcy case, or from disposing of security repossessed from such debtor, without bankruptcy court approval, which may not be given. Moreover, the bankruptcy code permits the debtor to continue to retain and use collateral even though the debtor is in default under the applicable debt instruments, provided that the secured creditor is given “adequate protection.” The meaning of the term “adequate protection” may vary according to circumstances, but it is intended in general to protect the value of the secured creditor’s interest in the collateral as of the commencement of the bankruptcy case and may include cash payments or the granting of additional security if and at such times as the bankruptcy court in its discretion determines that the value of the secured creditor’s interest in the collateral is declining during the pendency of the bankruptcy case. A bankruptcy court may determine that a secured creditor may not require compensation for a diminution in the value of its collateral if the value of the collateral exceeds the debt it secures.

In view of the lack of a precise definition of the term “adequate protection” and the broad discretionary power of a bankruptcy court it is impossible to predict:

• how long payments under the senior secured notes could be delayed following commencement of a bankruptcy case;

• whether or when the collateral agent could repossess or dispose of the collateral;

• the value of the collateral at the time of the bankruptcy petition; or

• whether or to what extent holders of the senior secured notes would be compensated for any delay in payment or loss of value of the collateral through the requirement of “adequate protection.”

In addition, the intercreditor agreement provides that, in the event of a bankruptcy, the trustee and the second lien collateral agent may not object to a number of important matters following the filing of a bankruptcy petition so long as any first priority lien obligations are outstanding. After such a filing, the value of the collateral securing the senior secured notes could materially deteriorate and the holders of the senior secured notes would be unable to raise an objection. The right of the holders of obligations secured by first priority liens on the collateral to foreclose upon and sell the collateral upon the occurrence of an event of default also would be subject to limitations under applicable bankruptcy laws if we or any of our subsidiaries become subject to a bankruptcy proceeding.

Any disposition of the collateral during a bankruptcy case would also require permission from the bankruptcy court. Furthermore, in the event a bankruptcy court determines the value of the collateral is not sufficient to repay all amounts due on first priority lien debt and, thereafter, the senior secured notes, the holders of the senior secured notes would hold a secured claim only to the extent of the value of the collateral to which the holders of the senior secured notes are entitled and unsecured claims with respect to such shortfall. The bankruptcy code only permits the payment and accrual of post-petition interest, costs and attorney’s fees to a secured creditor during a debtor’s bankruptcy case to the extent the value of its collateral is determined by the bankruptcy court to exceed the aggregate outstanding principal amount of the obligations secured by the collateral.

***A court could void the liens securing the guarantees or the senior secured notes under fraudulent transfer laws.***

Although the senior secured notes and guarantees will be secured by the collateral owned by us and the guarantors, under the federal bankruptcy laws and comparable provisions of state fraudulent transfer laws, a lien could be voided, or claims with respect to a lien could be subordinated to all other debts of that obligor. In addition, a bankruptcy court could require enforcement proceeds from the collateral to be returned to the obligor or to a fund for the benefit of the other creditors of the obligor. Each guarantee will contain a provision intended to limit the guarantor’s liability to the maximum amount that it could incur without causing the incurrence of obligations under its senior secured notes and guarantee to be a fraudulent transfer. This provision may not be effective to protect the liens securing the senior secured notes and the guarantees from being voided under fraudulent transfer law.

The bankruptcy court might take these actions if it found, among other things, that when an obligor granted its lien:

• such obligor received less than reasonably equivalent value or fair consideration for the granting of the lien; and

• such obligor:

• was (or was rendered) insolvent by the incurrence of the obligation;

• was engaged or about to engage in a business or transaction for which its assets constituted unreasonably small capital to carry on its business;

• intended to incur, or believed that it would incur, obligations beyond its ability to pay as those obligations matured; or

• was a defendant in an action for money damages, or had a judgment for money damages docketed against it and, in either case, after final judgment, the judgment was unsatisfied.

A bankruptcy court would likely find that an obligor received less than fair consideration or reasonably equivalent value for its lien to the extent that it did not receive direct or indirect benefit from the issuance of the senior secured notes. A bankruptcy court could also void a lien if it found that the subsidiary issued its lien with actual intent to hinder, delay or defraud creditors.

Although courts in different jurisdictions measure solvency differently, in general, an entity would be deemed insolvent if the sum of its debts, including contingent and unliquidated debts, exceeds the fair value of its assets, or if the present fair salable value of its assets is less than the amount that would be required to pay the expected liability on its debts, including contingent and unliquidated debts, as they become due.

If a court voided a lien, it could require that noteholders return any enforcement proceeds from the collateral. If any lien were voided, noteholders would retain their rights against us and any guarantors, although there is no assurance that those entities’ assets would be sufficient to pay the senior secured notes in full.

***Any future pledge of collateral might be avoidable in bankruptcy.***

Any future pledge of collateral in favor of the second lien collateral agent, including pursuant to mortgages and other security documents delivered after the date of the indenture governing the senior secured notes, might be avoidable by the pledgor (as debtor-in-possession) or by its trustee in bankruptcy if certain events or circumstances exist or occur, including, among others, if the pledgor is insolvent at the time of the pledge, the pledge permits the holders of the senior secured notes to receive a greater recovery than if the pledge had not been given and a bankruptcy proceeding in respect of the pledgor is commenced within 90 days following the pledge or, in certain circumstances, a longer period.

***The collateral is subject to casualty risks.***

We maintain insurance or otherwise insure against certain hazards. There are, however, losses that may be not be insured. If there is a total or partial loss of any of the pledged collateral, we cannot assure you that any insurance proceeds received by us will be sufficient to satisfy all the secured obligations, including the senior secured notes, our new senior secured term loan and related guarantees.

***The representative of the lenders under the senior secured term loan will initially control actions with respect to the Secured Notes/Term Loan Priority Collateral. In addition, subject in all respects to the intercreditor agreement with the holders of obligations under the RBL Facility, the representative of the lenders under the senior secured term loan will also conduct all actions with respect to the RBL Facility Priority Collateral held by the holders of obligations having a second‑priority security interest in such assets.***

The rights of the holders of the senior secured notes with respect to the Secured Notes/Term Loan Priority Collateral and RBL Facility Priority Collateral will be subject to an intercreditor agreement with the lenders under the senior secured term loan and other pari passu obligations. Under that intercreditor agreement, any action that may be taken with respect to the collateral, including the ability to cause the commencement of enforcement proceedings against such collateral, will be at the direction of the authorized representative of the lenders under the senior secured term loan until (1) our obligations under the senior secured term loan are discharged or (2) (i) 180 days after the occurrence of an event of default under the senior secured notes indenture or the senior secured term loan and (ii) the acceleration of the obligations under the senior secured notes indenture or the senior secured term loan. In addition, the intercreditor agreement will provide that, so long as the senior secured term loan obligations are in effect, the holders of the senior secured notes may not contest, protest or object to any foreclosure proceeding or action brought by the authorized representative of the lenders under the senior secured term loan (subject to limited exceptions). The collateral will also be subject to any and all exceptions, defects, encumbrances, liens and other imperfections as may be accepted by the authorized representative of the lenders under the senior secured term loan. See “Description of Senior Secured Exchange Notes.”

**Additional Risks Related to the Senior Notes**

***The senior notes are unsecured, and the senior notes will be effectively subordinated to any existing and future secured debt.***

The senior notes are unsecured and will rank equal in right of payment with our existing and future unsecured and unsubordinated senior debt. The senior notes will not be secured by any of our or the guarantors’ assets. The senior notes will be effectively subordinated to the senior secured notes, the RBL Facility, the senior secured term loan and any future secured debt to the extent the value of the assets that secure the indebtedness. The effect of this subordination is that upon a default in payment on, or the acceleration of, any of our secured indebtedness, or in the event of bankruptcy, insolvency, liquidation, dissolution or reorganization of us or the guarantors of the senior secured notes, the RBL Facility, the senior secured term loan or of other secured debt, the proceeds from the sale of assets securing our secured indebtedness will be available to pay obligations on the senior notes only after all indebtedness under the senior secured notes, the RBL Facility, the senior secured term loan and the other secured debt has been paid in full. As a result, the holders of the senior notes may receive less, ratably, than the holders of secured debt in the event of our or the guarantors’ bankruptcy, insolvency, liquidation, dissolution or reorganization. As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, there would have been secured debt consisting of $400 million under the RBL Facility (as well as approximately $1.5 billion of undrawn commitments), $750 million of the senior secured notes and $750 million under the senior secured term loan.

**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 supply and demand for oil, natural gas and NGLs which will depend on many other factors outside of our control, which include, among others:

• 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 of demand for natural gas, 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 others 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 NGL and Canadian supplies and alternate fuels; and

• increased costs to explore for, develop and produce oil, natural gas or NGLs, including increases in oil field service costs.

***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. Oil, natural gas and NGL prices historically have been highly volatile and are likely to continue to be volatile in the future, especially given current global geopolitical and economic conditions. There is a risk that commodity prices could remain depressed for sustained periods, especially natural gas prices, which are at historical ten year low levels at this time. Subject to our risk mitigation and hedging strategies, we are not likely to be impacted by short-term changes in commodity prices. However, we can be negatively impacted in the long-term by sustained depression in commodity 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;

• 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;

• commodity processing, gathering and transportation availability, proximity and cost, and the availability, proximity and cost of refining capacity;

• the price and availability of supplies of alternative energy sources;

• the effect of NGL deliveries to 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 these commodity prices could negatively impact our proven oil and natural gas reserves, which could cause us to incur non-cash charges to earnings. Approximately 70% of our proved reserves at December 31, 2011 were natural gas and approximately 84% of our production for the year ended December 31, 2011 was natural gas, and as a result we are substantially more sensitive to changes in natural gas prices than to changes in oil and NGL prices. Current natural gas prices are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. Such decreases in commodity prices could negatively 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 NGL 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.

***If oil and natural gas prices decrease, we may be required to take write‑downs of the carrying values of our oil 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 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 undeveloped leasehold costs are assessed for impairment at a lease level or resource play 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 a field discovers lower than anticipated reserves, reservoirs produce below original estimates 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.

We may incur additional 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. Finally, in light of the recent decline in natural gas prices, it is possible we could experience impairment charges for our domestic natural gas properties in the future. 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 use of derivative financial instruments could result in financial losses or could reduce our income.***

We use futures, over-the-counter options and swaps to mitigate our commodity price, basis and interest rate exposures. However, we do not typically hedge all of these exposures. For example, we do not typically hedge positions beyond several years with regard to commodity or basis risks. As a result, we are subject to commodity price and basis exposure since our business has multi-year drilling programs for our proved reserves and unproved resources.

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

To the extent we enter into derivative contracts to manage our commodity price exposure, basis and interest rate exposures, we may forego the benefits we could otherwise experience if such prices, differentials or rates were to change favorably. In addition, when we enter into fixed price derivative contracts, we could experience losses and be required to pay cash to the extent that commodity prices, basis positions or interest 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;

• 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.

These types of hedging arrangements could also limit the benefit we would receive from increases in the prices for natural gas or oil.

Our counterparties are typically large financial institutions. The risk that a counterparty may default on its obligations is heightened by the recent financial sector crisis and losses incurred by many banks and other financial institutions, including our counterparties or their affiliates. These losses may affect the ability of the counterparties to meet their obligations to us on hedge transactions, which would reduce our revenue from hedges at a time when we are also receiving a lower price for our oil and natural gas sales, thereby triggering the hedge payments. As a result, our business, results of operations and financial condition could be materially adversely affected.

In addition, our commodity price risk management activities could have the effect of reducing our revenue and net income. For the year ended December 31, 2011 and the six months ended June 30, 2012, the net unrealized asset represented by our hedging contracts was $201 million and $460 million, respectively. We may continue to incur significant unrealized gains or losses in the future from our commodity price risk management 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.***

On July 21, 2010, The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (“Dodd-Frank”) was signed into law. Title VII of Dodd-Frank (“Title VII”) imposes comprehensive regulation on the over-the-counter (“OTC”) derivatives marketplace and could affect the use of derivatives in hedging transactions. Among other things, Title VII subjects swap dealers and major swap participants to substantial supervision and regulation, including capital standards, margin requirements, business conduct standards and recordkeeping and reporting requirements. Title VII also requires central clearing for many transactions entered into between swap dealers, major swap participants and other entities unless an End‑User Exemption is available. All swaps subject to the clearing requirement must be executed on a regulated exchange or a swap execution facility (“SEF”), unless no exchange or SEF makes it available for trading. For these purposes, it is expected that a major swap participant generally will be someone other than a dealer (i) who maintains a “substantial” net position in outstanding swaps, excluding swaps used for commercial hedging or for reducing or mitigating commercial risk or (ii) whose positions create substantial net counterparty exposure that could have material adverse effects on the financial stability of the U.S. banking system or financial markets. In addition, Title VII provides the Commodity Futures Trading Commission (the “CFTC”) with express authority to impose aggregate position limits on derivatives related to energy commodities, including contracts traded on exchanges, SEFs, non-U.S. boards of trade and swaps that are not centrally cleared. The CFTC has proposed a large number of rules to implement Title VII in multiple rulemaking proceedings and has finalized a number of such rules, such as the rule on the end user exception to certain clearing, margin and reporting requirements applicable to derivatives transactions on July 10, 2012. Specifically, the CFTC has issued finance regulations to define the terms “swap,” “swap dealer” and “major swap participant.” In addition, the CFTC has issued final regulations regarding registration of swap dealers and major swap participants. The CFTC has also issued final regulations on position limits for futures and swaps, which became effective sixty days after the term “swap” was defined by the CFTC. The CFTC has also issued final regulations on real-time public reporting of swap transaction and pricing data, as well as final regulations regarding recordkeeping and reporting requirements. Under Dodd-Frank, the CFTC was generally given until July 16, 2011 to adopt final rules under Title VII, though some rules were required to be completed sooner. However, most of the contemplated rules were not adopted by such date. Since certain provisions of Dodd-Frank reference terms that required further definition or repeal provisions of current law, such provisions would not become effective until there was a final rulemaking with respect thereto. To address the consequences of this regulatory backlog and avoid “undue disruption” to current practices during the transition to the new regulatory regime, the CFTC issued a final order, effective December 23, 2011, which (i) delays the effectiveness of provisions which reference certain terms that require further definition until the earlier of the effective date of the final rule defining the referenced term or July 16, 2012 and (ii) adds provisions to account for the repeal and replacement (as of December 31, 2011) of part 35 of the CFTC’s regulations. Part 35 provided a safe harbor from CFTC regulation for certain transactions between “eligible swap participants,” until the earlier of the repeal, withdrawal or replacement of Part 35 or December 31, 2011. The CFTC continues to propose and finalize rules to implement Title VII in multiple rulemaking proceedings. It is not possible at this time to predict the outcome of these proceedings or, in the case of final rules, the impact that such rules will have on the new regulatory regime and the OTC derivatives marketplace. Any laws or regulations that may be adopted that subject us or our counterparties to additional capital or margin requirements and substantially increase the costs associated with hedging our equity production, potentially making it more expensive, or limiting our ability, to implement our hedging program. In addition, the position limits implemented under the new regulatory regime may effectively limit our ability to implement our hedging program.

***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 replace our production. We have established a capital budget for 2012 between $1.5 billion and $1.6 billion. We plan to use cash flow from operating activities and borrowings under the RBL Facility to fund our capital expenditures in 2012.

We intend to rely on cash flow from operating activities and borrowings under the RBL Facility as our primary sources of liquidity. We also may engage in asset sale transactions to 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 private or public 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 replace our reserves or maintain our 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, or if we have a downward revision in estimates of our proved reserves, our borrowing base may be reduced.

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

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

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

The oil, natural gas and NGL 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.

***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, property could be damaged and/or customer information could be stolen 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 (such as damage from collisions with vessels in our exploration and production operations); 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 may encounter additional marine perils, including hurricanes and other 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 outcomes could have a material adverse effect on our business, results of operation 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 our inability to maintain these relationships and find appropriate partners for our operations in the future could 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. The most significant joint venture is our approximate 49% equity interest in Four Star. Although we operate the substantial majority of the properties in our business, certain of the properties are operated by our joint venture partners or other third‑party working interest owners. In certain cases, (a) we have limited ability to influence or control the day-to-day operation of such properties, including compliance with environmental, safety and other regulations, (b) we cannot control the amount of capital expenditures that we are required to fund with respect to properties, (c) we are dependent on third parties to fund their required share of capital expenditures and (d) 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 are subject to a complex set of laws and regulations that regulate the energy industry for which we have to incur substantial compliance and remediation costs.***

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

• the location of wells;

• methods of drilling and completing wells;

• allowable production from wells;

• unitization or pooling of oil and gas properties;

• spill prevention plans;

• limitations on venting or flaring of natural gas;

• disposal of fluids used and wastes generated in connection with operations;

• access to, and surface use and restoration of, well properties;

• plugging and abandoning of wells;

• air quality, noise levels and related permits;

• gathering, transportation and marketing of natural gas (including NGLs) and oil;

• taxation; and

• competitive bidding rules on federal and state lands.

Generally, the regulations have become more stringent over time and impose more limitations on our operations and cause more costs to be incurred to comply with such increased regulation. 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 drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with excessive conditions or costs could have a material negative impact on our operations and financial results. We may also incur substantial costs in order to maintain compliance with these existing laws and regulations, including costs to comply with new and more extensive reporting and disclosure requirements. Failure to comply with such requirements may result in the suspension or termination of operations and may subject us to criminal as well as civil and administrative penalties. We are exposed to fines and penalties to the extent that we fail to comply with the applicable laws and regulations, as well as the potential for limitations to be imposed on our operations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Also, some of our assets are located and operate on federal, state, local or tribal lands and are typically regulated by one or more federal, state or local agencies. For example, we have drilling and production operations that are located on federal lands, which are regulated by the U.S. Department of the Interior (“DOI”), particularly by the Bureau of Land Management (“BLM”) and the Bureau of Ocean Energy Management, Regulation and Enforcement. 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 (“FTC”) and the Commodity Futures Trading Commission (“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, and our credit risk management may not be adequate to protect against such risk.***

We are subject to the risk that our counterparties may fail to make payments to us within the time required under our contracts or at all. Our current largest exposure is with some of our hedging transaction counterparties. Our credit procedures and policies may not be adequate to fully eliminate counterparty credit risk. In addition, in certain situations, we may assume certain additional credit risks for competitive reasons or otherwise. If our existing or future counterparties fail to pay and/or perform, our business, results of operation and financial condition could be materially adversely affected.

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

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

***Affiliates of the Sponsors and other investors own substantially all of the equity interests in us may have conflicts of interest with us and or the holders of the notes in the future.***

As a result of the Acquisition Transactions, investment funds affiliated with, and one or more co-investment vehicles controlled by, the Sponsors and other investors collectively own substantially all of our equity interests and such persons or their designees hold substantially all of the seats on Parent’s board of managers. As a result, affiliates of the Sponsors and such other investors have control over our decisions to enter into certain corporate transactions and have the ability to prevent any transaction that requires the approval of stockholders, regardless of whether holders of the notes believe that any such transactions are in their own best interests. For example, affiliates of the Sponsors and other investors could collectively cause us to make acquisitions that increase the amount of our indebtedness or to sell assets, or could cause us to issue additional capital stock or declare dividends. So long as investment funds affiliated with the Sponsors and other investors continue to indirectly own a significant amount of the outstanding shares of our equity interests or otherwise control a majority of Parent’s board of managers, affiliates of the Sponsors and other investors will continue to be able to strongly influence or effectively control our decisions. The indentures governing the notes and the credit agreements governing the RBL Facility and our new senior secured term loan permit us, under certain circumstances, to pay advisory and other fees, pay dividends and make other restricted payments to the Sponsors and other investors, and the Sponsors and such other investors or their respective affiliates may have an interest in our doing so.

Additionally, the Sponsors and such other investors are in the business of making investments in companies and may from time to time acquire and hold interests in businesses that compete directly or indirectly with us or that supply us with goods and services. These persons may also pursue acquisition opportunities that may be complementary to (or competitive with) our business, and as a result those acquisition opportunities may not be available to us. In addition, the Sponsors’ and other investors’ interests in other portfolio companies could impact our ability to pursue acquisition opportunities. The holders of the notes should consider that the interests of the Sponsors and such other investors (or their respective affiliates) may differ from their interests in material respects. See “Summary—Our Sponsors” and “Certain Relationships and Related Party Transactions.”

***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 are not protected by 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. For information regarding these employment agreements, see “Management—Employment Agreements.” The unexpected loss of services of one or more of these individuals 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 could result in the inability to implement our business plans.***

Our business requires the retention and recruitment of a skilled workforce including engineers, technical personnel, geoscientists and land personnel and other professionals. We compete with other companies in the energy industry for this skilled workforce. We have developed new firm-wide compensation and benefit programs that took effect following the Acquisition Transactions. These new programs are based on previous Company plans and are designed to be competitive among our industry peers and to reflect market‑based metrics as well as incentives to create alignment with the Sponsors and other investors, but there is a risk that these new programs may not be successful in retaining and recruiting these professionals or that we could experience increased costs. If we are unable to (a) retain our current employees, (b) successfully complete our knowledge transfer and/or (c) 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.

***Skilled labor shortages and increased labor costs could negatively impact our profitability.***

We may be affected by skilled labor shortages of certain types of technical or qualified personnel, including engineers, geo-professionals, project managers, field supervisors and other technical or qualified personnel, 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.

***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 (such as if our access to capital resources becomes 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 natural gas and oil 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. We have incurred unevaluated capitalized costs associated with development and exploration activities in Brazil. 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 producible reservoirs, we either may not fully recover our investments or that our rates of return will be less than expected. We are also subject to the risk that we encounter unexpected drilling conditions. Our past performance should not be considered indicative of future drilling performance. For example, we have acquired acreage positions in two new 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 exploring for the reserves in these regions or in developing the reserves that are found. Our success in such areas will depend in part on our ability to successfully transfer our experiences from existing areas into these new shale plays. As a result, there remains uncertainty on the results of our drilling programs, including our ability to realize proved reserves or to earn acceptable rates of return on our drilling programs. From time to time, we provide forecasts of expected quantities of future production. These forecasts are based on a number of estimates, including expectations of production from existing wells and the outcome of future drilling activity. Our forecasts could be different from actual results and such differences could be material.

Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. In addition, the results of our exploratory drilling in new or emerging areas are more uncertain than drilling results in areas that are developed and have established production. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economic than forecasted. Further, many factors may increase the cost of, or curtail, delay or cancel, drilling operations, including the following:

• unexpected drilling conditions;

• delays imposed by or resulting from compliance with regulatory and contractual requirements;

• unexpected pressure or irregularities in geological formations;

• equipment failures or accidents;

• fracture stimulation accidents or failures;

• adverse weather conditions;

• declines in oil and natural gas prices;

• surface access restrictions with respect to drilling or laying pipelines;

• shortages (or increases in costs) of water used in hydraulic fracturing, especially in arid regions or regions that have been experiencing severe drought conditions;

• shortages or delays in the availability of, increases in the cost of, or increased competition for, drilling rigs and crews, fracture stimulation crews, equipment, pipe, chemicals and supplies and transportation, gathering, processing, treating or other midstream services; and

• limitations or reductions in the market for natural gas and oil.

Additionally, the occurrence of certain of these events 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 result in our inability to realize an acceptable return on our investments in such projects. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of natural gas and oil in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects. Further, 2-D and 3-D seismic data that we obtain is subject to interpretation and may not accurately identify the presence of natural gas, which could also negatively impact the results of our drilling operations.

***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 drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, limited access to gathering systems and takeaway capacity, and/or oil and natural gas prices decline, 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. In summary, 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. In addition, we may not be able to raise the significant amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.***

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 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 NGL prices, costs and drilling results. Because of these uncertainties, we do not know if the drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

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

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

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

The marketability of our oil, natural gas and NGL production depends in large part on the operation, availability, proximity, capacity and expansion of 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 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:

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

• we may assume liabilities that were not disclosed to us and for which contractual protections prove inadequate or that exceed our estimates;

• properties we acquire may be subject to burdens on title that we were not aware of at the time of acquisition, 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;

• acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures;

• 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;

• an inability to implement uniform standards, controls, procedures and policies;

• 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;

• potential loss of key customers; and

• potential loss of key employees, including 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, we do have provisions in many of our leases that provide for the lease to expire unless certain conditions are met, such as drilling having commenced on the lease or production in paying quantities having been obtained within a defined time period. If commodity prices remain low or we are unable to fund our anticipated capital program there is a risk that some of our existing proved reserves and some of our unproved inventory could be subject to lease expiration or a requirement to incur additional leasehold costs to extend the lease. This could result in a reduction in our reserves and our growth opportunities (or the incurrence of significant costs) and therefore could have a material adverse effect on our financial results.

***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, losses and impairments.***

All estimates of proved reserves are determined according to the rules prescribed by the SEC. Our reserve information was prepared internally and was audited by an independent petroleum consultant. There are numerous uncertainties involved in estimating proved reserves, which may result in these estimates varying considerably from actual results. Estimating quantities of proved reserves is complex and involves significant interpretations 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, as the portion of our proved reserve base that consists of unconventional resources increases, 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.

In addition, if our cash flows or the borrowing base under the RBL Facility decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may be required to seek additional debt or equity financing to sustain our operations at current levels. If we are unable to secure sufficient capital to meet our capital requirements, we may be required to curtail operations, which could lead to a possible decline in our reserves and could have a material adverse effect on our business, results of operations and financial condition.

***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, as well as regulations designed for the protection of threatened or endangered species. In some cases, our operations are subject to federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to state regulations relating to conservation practices and protection of correlative rights. These regulations may negatively impact our operations and limit the quantity of natural gas and oil we produce and sell. We must take into account the cost of complying with such requirements in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities, including gathering, transportation, storage and waste disposal facilities. The regulatory frameworks govern, and often require permits for, the handling of drilling and production materials, water withdrawal, disposal of produced water, drilling and production wastes, operation of air emissions sources, and drilling activities, including those conducted on lands lying within wilderness, wetlands, Federal and Indian lands and other protected areas. Various governmental authorities, including the U.S. Environmental Protection Agency (“EPA”), the DOI, the BIA and analogous state agencies and tribal governments, have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions, such as installing and maintaining pollution controls and maintaining measures to address personnel and process safety and protection of the environment and animal habitat near our operations. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases. Our exploration and production operations in Brazil are subject to various types of regulations similar to those described above, which are imposed by the government of the country in which we operate (including political subdivisions in those countries), and which may affect our operations and costs within those countries. 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.

In addition, there have been various legislative and regulatory proposals at the federal and state levels to address climate change and to regulate greenhouse gas (“GHG”) emissions. The EPA and several state environmental agencies have already adopted regulations to regulate GHG emissions. Although natural gas as a fuel supply for power generation has the least GHG emissions of any fossil fuel, it is uncertain at this time what impact the existing and proposed regulations will have on the demand for natural gas and on our operations. This impact will largely depend on what regulations are ultimately adopted, including the level of any emission standards, the amount and costs of allowances, offsets and credits granted and any incentives and subsidies provided to other fossil fuels, nuclear power and renewable energy sources. In May 2010, the EPA adopted its “Tailoring Rule” concerning regulation of large emitters of GHGs under the Clean Air Act’s Prevention of Significant Deterioration (“PSD”) and Title V programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources subject to permitting first. Facilities required to obtain PSD permits for their GHG emissions will also be required to meet “best available control technology” standards, which will be established by states or, in some instances, the EPA on a case-by-case basis. The Tailoring Rule is not expected to materially impact our operations until 2016. There have also been various legislative and regulatory proposals at the federal and state levels to address various emissions from coal-fired power plants. Although such proposals will generally favor the use of natural gas-fired power plants over coal-fired power plants, 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 requiring us to monitor such emissions, to install additional equipment to reduce carbon emissions and possibly to purchase emission credits. Any such regulations also could potentially delay the receipt of permits and other regulatory approvals. While we may be able to include some or all of the costs associated with our environmental liabilities and environmental compliance in the prices at which we sell oil, natural gas and NGLs, our ability to recover such costs is uncertain and may depend on events beyond our control.

In addition to the EPA initiatives, the U.S. Congress has considered legislation that would establish a nationwide cap-and-trade system for GHGs. If enacted, such laws and regulations could require us to modify existing, or obtain new, permits, implement additional pollution control technology, curtail operations or increase significantly our operating costs.

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

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

***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. 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 a recent explosion on an offshore platform of a third party 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, 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 operation 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 currently use hydraulic fracturing extensively in all of our key programs. Hydraulic fracturing typically involves the injection of water, sand and additives under pressure into rock formations in order to stimulate hydrocarbon production. We find that the use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many of the reservoirs in which we operate. Recently, there have been a number of initiatives and proposed initiatives at the federal, state and local level to ban or regulate hydraulic fracturing and to study the environmental impacts of hydraulic fracturing and the need for further regulation of the practice. For example, debate has intensified over whether certain of the chemical constituents in hydraulic fracturing fluids may contaminate drinking water supplies, with some members of Congress and others proposing to revisit the exemption of hydraulic fracturing from the permitting requirements of the Safe Drinking Water Act (the “SDWA”). Eliminating this exemption could establish an additional level of regulation and permitting at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Even in the absence of new legislation, the EPA recently asserted the authority to regulate hydraulic fracturing involving the use of diesel additives under the SDWA’s Underground Injection Control Program.

Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing on drinking water, the initial results of which are anticipated to be available by late 2012. Hydraulic fracturing operations require the use of water and the disposal or recycling of water that has been used in operations. The federal Clean Water Act (the “CWA”) restricts the discharge of produced waters and other pollutants into waters of the United States and requires permits before any pollutants may be discharged. The CWA and comparable state laws and regulations provide for penalties for unauthorized discharges of pollutants including produced water, oil, and other hazardous substances. Compliance with and future revisions to requirements and permits governing the use, discharge, and recycling of water used for hydraulic fracturing may increase our costs and cause delays, interruptions or terminations of our operations which cannot be predicted.

The EPA has also taken actions to regulate air emissions from hydraulic fracturing operations. 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. These regulations will limit emissions from the hydraulic fracturing of certain natural gas wells and from certain equipment including compressors, storage vessels and natural gas processing plants. These regulations require reduction of flowback emissions from gas wells effective October 15, 2012 and use of “green completions” effective January 1, 2015. We have developed plans to meet the new regulations.

Several states have also adopted or are considering legislation requiring the disclosure of fracturing fluids and other restrictions on hydraulic fracturing operations, including states in which we operate. The DOI is also considering disclosure requirements or other mandates for hydraulic fracturing on federal land, which, if adopted, would affect our operations on federal lands. The Department of Energy (the “DOE”) is also considering whether to implement actions to lessen the environmental impact associated with hydraulic fracturing operations. Initiatives by the EPA and other federal and state regulators to expand their regulation of hydraulic fracturing, together with the possible adoption of new federal or state laws or regulations that significantly restrict hydraulic fracturing, could result in delays, eliminate certain drilling and injection activities, make it more difficult or costly for us to perform hydraulic fracturing, increase our costs of compliance and doing business, and delay or prevent the development of unconventional hydrocarbon resources from shale and other formations that are not commercial without the use of hydraulic fracturing. In addition, there have been proposals by non-governmental organizations to restrict certain buyers from purchasing oil and natural gas produced from wells that have utilized hydraulic fracturing in their completion process, which could negatively impact our ability to sell our production from wells that utilized these fracturing processes.

***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. Among the changes contained in President Obama’s budget proposal for fiscal year 2013, released by the White House on February 13, 2012, is the elimination of 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.

Members of Congress have introduced legislation with similar provisions in the current session. 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.

The Issuer is classified as an entity disregarded from Parent for U.S. federal income tax purposes, and Parent is classified as a partnership for U.S. federal and applicable state and local income tax purposes. As a result, neither the Issuer nor Parent pays U.S. federal, state or local income tax; rather, the direct and indirect owners of Parent must report and pay U.S. federal, state and local income tax on their distributive share of the income, gain, loss, deduction and credit recognized by Parent. Changes in U.S. federal and applicable state and local income tax law (such as the proposals listed above) may increase the U.S. federal and applicable state and local income tax liability of the direct and indirect owners of Parent and the Issuer may be obligated to distribute greater amounts indirectly to such owners on account of such increased U.S. federal and applicable state and local income tax liability.

***Our foreign operations and investments involve special risks.***

Our activities in Brazil are subject to the risks inherent in foreign operations and other additional risks not associated with assets located in the United States, which include, among others:

• protracted delays in securing government consents, permits, licenses, customer authorizations or other regulatory approvals necessary to conduct our operations, including those required in Brazil for the Pinauna project;

• 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;

• 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. See Note 8 to our condensed consolidated financial statements and 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 have recently experienced a period of unprecedented turmoil and upheaval characterized by the bankruptcy, failure, collapse or sale of various financial institutions and an unprecedented level of intervention from the United States government. These circumstances and events led to reduced credit availability, tighter lending standards and higher interest rates on loans. While we cannot predict the future condition of the credit markets, future turmoil in the credit markets could have a material adverse effect on our business, liquidity, financial condition and cash flows, particularly if our ability to borrow money from lenders or access the capital markets to finance our operations were to be impaired.

Although we believe that the banks participating in the RBL Facility have adequate capital and resources, we can provide no assurance that all of those banks will continue to operate as a going concern 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.

**MARKET AND INDUSTRY DATA**

We include 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” in this prospectus.

**CAUTIONARY STATEMENT CONCERNING FORWARD‑LOOKING STATEMENTS**

This prospectus and certain oral statements made from time to time by us and our representatives contain “forward‑looking statements” within the meaning of the federal securities laws. You can identify forward‑looking statements because they contain words such as “believes,” “project,” “might,” “expects,” “may,” “will,” “should,” “seeks,” “approximately,” “intends,” “plans,” “estimates,” or “anticipates” or similar expressions that concern our strategy, plans or intentions. In addition, all statements herein about our 2012 capital expenditures, including our planned wells, and the characteristics of average future wells for our key areas, which are based on current internal engineering estimates as described under “Business—Operations—Key Program Profiles,” are forward‑looking statements. These forward‑looking statements are subject to risks and uncertainties that may change at any time, and therefore our actual results may differ materially from those that we expected. While we believe that the expectations reflected in such forward‑looking statements are reasonable, we caution that it is very difficult to predict the impact of known factors, and it is impossible to anticipate all factors that could affect our actual results.

Important factors that could cause actual results to differ materially from our expectations (“cautionary statements”) are disclosed under “Risk Factors” and elsewhere in this prospectus, including, without limitation, in conjunction with the forward‑looking statements included in this prospectus. All subsequent written and oral forward‑looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements. Some of the factors that we believe could affect our results include:

• the supply and demand and the prices for oil, natural gas and NGLs;

• our use of derivative financial instruments and derivatives reform legislation;

• competition from third parties;

• operational hazards and uninsured risks;

• joint ventures and operations by third parties;

• cost of, changes in, or the results of the complex set of laws and regulations (including climate change legislation and/or potential additional regulation of drilling and completion of wells, including hydraulic fracturing), to which we are subject;

• credit and performance risk of our counterparties;

• loss of services by key personnel and the retention and recruitment of a skilled workforce;

• the potential conflict of interest between the Sponsors’ and other investors’ interests and our creditors’ interests;

• our ability to find and replace reserves that we produce;

• risks associated with oil and natural gas drilling and producing operations;

• unsuccessful acquisitions;

• uncertainty with respect to our reserves;

• risks associated with our foreign operations;

• risks associated with negative developments in the capital markets; and

• the other factors described under “Risk Factors.”

We caution you that the foregoing list of important factors may not contain all of the material factors that are important to you. In addition, in light of these risks and uncertainties, the matters referred to in the forward‑looking statements contained in this prospectus or oral statements made by us or our representatives may not in fact occur. We undertake no obligation to publicly update or revise any forward‑looking statement as a result of new information, future events or otherwise, except as otherwise required by law.

**USE OF PROCEEDS**

We will not receive any cash proceeds from the issuance of the exchange notes in exchange for the outstanding initial notes. We are making this exchange solely to satisfy our obligations under the registration rights agreements entered into in connection with the offering of the initial notes. In consideration for issuing the exchange notes, we will receive initial notes in like aggregate principal amount.

The proceeds of the offering of the initial senior secured notes and initial 2020 senior notes were $2,750 million before the initial purchasers’ discount and estimated fees and expenses. We used the net proceeds from the offering, together with proceeds from our senior secured term loan, investments in Parent’s equity by funds affiliated with the Sponsors and other investors and borrowings under the RBL Facility to fund the Acquisition and to pay related transaction fees and expenses.

The proceeds of the offering of the initial 2022 senior notes were $350 million before initial purchasers’ discount and estimated fees and expenses. We used the proceeds of the offering to repay a portion of the borrowings under our RBL Facility.

**CAPITALIZATION**

The following table sets forth the cash and cash equivalents and capitalization as of June 30, 2012 for:

• the Issuer on an actual basis; and

• the Issuer on a pro forma basis after giving effect to the Refinancing Transactions.

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

|  |  |  |
| --- | --- | --- |
|  | **As of June 30, 2012** | |
|  | **Actual** | **Pro Forma for the Refinancing Transactions** |
|  | **(in millions)** | |
| Cash and cash equivalents | $55 | $41 |
| Long-term debt: |  |  |
| The RBL Facility(1)(2) | $750 | $400 |
| Senior secured term loan(3) | 750 | 750 |
| Senior secured notes | 750 | 750 |
| 9.375% senior notes | 2,000 | 2,000 |
| 7.750% senior notes(2) | — | 350 |
| Total long-term debt | $4,250 | $4,250 |
| Total members’ equity(4) | 3,158 | 3,149 |
| Total capitalization | $7,408 | $7,399 |

(1) In connection with the Acquisition Transactions, we entered into the RBL Facility, which will mature in 2017. We borrowed $750.0 million under the RBL Facility at the closing of the Acquisition to fund a portion of the Acquisition Transactions and to pay related fees and expenses. As of September 1, 2012, $350 million was drawn and outstanding under the RBL Facility.

(2) As part of the Refinancing Transactions, we issued $350.0 million aggregate principal amount of 7.750% senior notes due 2022 and used the proceeds of the notes to repay a portion of our borrowings under the RBL Facility.

(3) In connection with the Acquisition Transactions, we entered into our senior secured term loan, which will mature in 2018.

(4) Total stockholder’s/contributed equity primarily reflects the equity contribution by affiliates of the Sponsors and other investors of $3,324.0 million net of transaction fees of $175.0 million that were not capitalized as deferred financing fees.

**UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL DATA**

The unaudited pro forma condensed consolidated financial data of the Company presented below have been derived from the historical consolidated financial statements of EP Energy Corporation (the predecessor) included elsewhere in this prospectus. The unaudited pro forma condensed consolidated financial statements should be read in conjunction with “Presentation of Financial Information,” “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the historical consolidated financial statements and the notes to those statements included elsewhere in this prospectus.

The unaudited pro forma condensed consolidated statement of income for the year ended December 31, 2011 and for the six months ended June 30, 2012 has been prepared as though the Acquisition and Refinancing Transactions occurred as of January 1, 2011. The unaudited pro forma condensed consolidated balance sheet at June 30, 2012 has been prepared as though the Refinancing Transactions occurred on June 30, 2012.

The unaudited pro forma adjustments include the following items:

• changes in depreciation, depletion, and amortization resulting from the allocation of purchase price;

• changes resulting from the application of the successful efforts method of accounting for our oil and gas activities;

• the adjustment for an annual advisory fee to be paid to the Sponsors and other investors following the Acquisition;

• the changes in interest expense resulting from additional indebtedness incurred in connection with the Acquisition and re‑pricing of our term loan in connection with the Refinancing Transactions, including amortization of estimated deferred financing fees;

• the adjustment associated with the change in tax status of EP Energy Corporation in conjunction with the Acquisition;

• the proceeds from the issuance of the initial 7.750% senior notes and the related use of proceeds; and

• the reclassification of intercompany transactions to third‑party transactions.

The Acquisition is being accounted for as a business combination using the acquisition method of accounting. Accordingly, the purchase price has been allocated to the assets acquired and liabilities assumed based upon management’s estimates of fair value. The unaudited pro forma adjustments are based upon available information and certain assumptions that management believes are factually supportable and that are reasonable under the circumstance. Assumptions underlying the unaudited pro forma adjustments are described in the accompanying notes, which should be read in conjunction with this unaudited pro forma condensed consolidated financial data. We have made every effort to ensure our estimates are reasonable. Actual results can, and often do differ from estimates.

The unaudited pro forma condensed consolidated statement of income excludes non-recurring items, such as the write-off of debt issue costs and transaction costs associated with the Acquisition and Refinancing Transactions that are not capitalized as part of the Acquisition and Refinancing Transactions. The unaudited pro forma condensed consolidated financial data are presented for illustrative purposes only and do not purport to indicate the financial condition or results of operations of future periods or the financial condition or results of operations that actually would have been realized had the Acquisition and Refinancing Transactions been consummated on the dates or for the periods presented.

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 Statement Concerning Forward‑ Looking Statements.”

**Unaudited Pro Forma Condensed Consolidated Balance Sheet**

**As of June 30, 2012**

**(In millions)**

|  |  |  |  |
| --- | --- | --- | --- |
|  | **Historical EP Energy LLC** | **Pro Forma Adjustments** | **Pro Forma EP Energy LLC** |
| Current Assets |  |  |  |
| Cash and cash equivalents | $55 | $(14)(a) | $41 |
| Accounts receivable |  |  |  |
| Customer, net of allowance of less than $1 | 163 | — | 163 |
| Other | 30 | — | 30 |
| Assets from price risk management activities | 278 | — | 278 |
| Other | 72 | — | 72 |
| Total current assets | 598 | (14) | 584 |
| Property, plant and equipment, net | 6,982 | — | 6,982 |
| Other assets |  |  |  |
| Investments in unconsolidated affiliates | 236 | — | 236 |
| Assets from price risk management activities | 200 | — | 200 |
| Unamortized debt issue cost | 139 | 5(a) | 144 |
| Other | 11 | — | 11 |
|  | 586 | 5 | 591 |
| Total Assets | $8,166 | $(9) | $8,157 |
| Current Liabilities |  |  |  |
| Accounts payable |  |  |  |
| Trade | $107 | $— | $107 |
| Other | 268 | — | 268 |
| Other | 130 | — | 130 |
| Total current liabilities | 505 | — | 505 |
| Long-term debt | 4,243 | (350)(a) | 4,243 |
|  |  | 350(a) |  |
| Other long-term liabilities | 260 | — | 260 |
|  | 4,503 | — | 4,503 |
| Members’ Equity |  |  |  |
| Members’ equity | 3,158 | (9)(a) | 3,149 |
| Total members’ equity | 3,158 | (9) | 3,149 |
| Total Liabilities and members’ equity | $8,166 | $(9) | $8,157 |

**Notes to Unaudited Pro Forma Condensed Consolidated Balance Sheet**

(a) Reflects the pro forma net adjustment of $14 million to cash and cash equivalents reflecting the sources and uses of cash as if the Refinancing Transactions occurred on June 30, 2012, as follows (in millions):

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Sources of funds** |  |  | **Uses of funds** |  |  |
| 7.750% senior notes due 2022 | | $350 | RBL Facility | | $350 |
| Cash and cash equivalents | | 14 | Unamortized debt issue cost | | 5 |
|  | |  | Transaction fees and expenses | | 9 |
| Total sources | | $364 | Total uses | | $364 |

**Unaudited Pro Forma Condensed Consolidated Statements of Income (Loss)**

**For the six months ended June 30, 2012**

**(In millions)**

|  |  |  |  |
| --- | --- | --- | --- |
|  | **Historical EP Energy LLC** | **Pro Forma Adjustments** | **Pro Forma EP Energy LLC** |
| Operating revenues |  |  |  |
| Third parties | $756 | $— | $756 |
| Derivatives | 422 | — | 422 |
|  | 1,178 | — | 1,178 |
| Operating expenses |  |  |  |
| Transportation costs | 59 | — | 59 |
| Lease operating expenses | 117 | — | 117 |
| General and administrative expenses | 284 | 10(a) | 294 |
| Depreciation, depletion and amortization | 353 | (200)(b) | 153 |
| Ceiling test charges | 63 | (63)(c) | — |
| Exploration expense | 6 | 99(d) | 105 |
| Taxes, other than income taxes | 57 | — | 57 |
|  | 939 | (154) | 785 |
| Operating income | 239 | 154 | 393 |
| (Loss) earnings from unconsolidated affiliates | (6) | 6(e) | — |
| Other expense | (2) | — | (2) |
| Interest expense, net of capitalized interest: |  |  |  |
| Third parties | (67) | (88)(f) | (155) |
| Income before income taxes | 164 | 72 | 236 |
| Income tax expense (benefit) | 136 | (135)(g) | 1 |
| Net income | $28 | $207 | $235 |

**Unaudited Pro forma Condensed Consolidated Statement of Income**

**For the year ended December 31, 2011**

**(in millions)**

|  |  |  |  |
| --- | --- | --- | --- |
|  | **Historical(i) EP Energy Corporation** | **Pro Forma Adjustments** | **Pro Forma EP Energy LLC** |
| **Operating revenues** |  |  |  |
| Third parties | $948 | $634(h) | $1,582 |
| Affiliates | 634 | (634)(h) | — |
| Realized and unrealized gains on financial derivatives | 284 | — | 284 |
| Other | 1 | — | 1 |
|  | 1,867 | — | 1,867 |
| **Operating expenses** |  |  |  |
| Transportation costs | 85 | — | 85 |
| Lease operating expenses | 217 | — | 217 |
| General and administrative expenses | 201 | 25(a) | 226 |
| Depreciation, depletion and amortization | 612 | (350)(b) | 262 |
| Ceiling test charges/impairment | 152 | (58)(c) | 94 |
| Impairment of inventory and other assets | 6 | — | 6 |
| Exploration expense |  | 155(d) | 155 |
| Taxes, other than income taxes | 91 | — | 91 |
|  | 1,364 | (228) | 1,136 |
| Operating income | 503 | 228 | 731 |
| (Loss) earnings from unconsolidated affiliates | (7) | 12(e) | 5 |
| Other expense | (2) | — | (2) |
| Interest expense, net of capitalized interest: |  |  |  |
| Third parties | (9) | (298)(f) | (310) |
|  |  | (3)(h) |  |
| Affiliates | (3) | 3(h) | — |
| Income before income taxes | 482 | (58) | 424 |
| Income tax expense (benefit) | 220 | (227)(g) | (7) |
| Net income | $262 | $169 | $431 |

**Notes to Unaudited Pro Forma Condensed Consolidated Statement of Income**

(a) Reflects the pro‑rata adjustment to record estimated annual advisory fees ($25 million annually) paid to affiliates of the Sponsors and other investors for management, consulting and financial services provided.

(b) Reflects the estimated adjustment to depreciation, depletion and amortization due to the fair value adjustments to our property, plant and equipment and the application of the successful efforts method of accounting. The pro forma depreciation, depletion and amortization rates were calculated using the year end 2011 proved reserves held constant throughout both periods in 2011 and 2012. It also assumes no reserve additions or changes in existing proved reserve categories beyond those existing at the balance sheet date. The pro forma depreciation, depletion and amortization rates were applied to production volumes in the respective periods.

(c) Reflects the removal of international ceiling test charges of $63 million for the six months ended June 30, 2012 and $152 million for the twelve months ended December 31, 2011 under the full cost method of accounting offset by impairment of $94 million due to the denial of a necessary environmental permit for a Brazilian development project under the successful efforts method of accounting for the twelve months ended December 31, 2011.

(d) Reflects exploratory dry hole costs, delay rentals, and seismic costs expensed under the successful efforts method of accounting.

(e) Reflects an estimated adjustment to (loss) earnings from unconsolidated affiliates due to the reduction of the amortization of the excess of our investment in Four Star Oil & Gas Company relative to the underlying equity in the net assets resulting from the fair value adjustment to our investment.

(f) Reflects the estimated adjustment to interest expense, net of capitalized interest, resulting from our new capital structure as follows (in millions):

|  |  |  |
| --- | --- | --- |
|  | **Six Months ended June 30, 2012** | **Year ended December 31, 2011** |
| Interest on the RBL Facility, senior secured term loan, senior secured notes and senior notes(1) | $156 | $313 |
| Amortization of capitalized deferred financing fees and original issue discount(2) | 16 | 30 |
| Commitment fees(3) | 3 | 6 |
| Capitalized interest expense(4) | (20) | (39) |
| Total pro forma interest expense, net of capitalized interest | 155 | 310 |
| Less: historical interest expense, net of capitalized interest(5) | (67) | (12) |
| Pro forma net adjustment to interest expense, net of capitalized interest | $88 | $298 |

(1) Represents interest on the RBL Facility, senior secured term loan, senior secured notes and senior notes, at a weighted average interest rate. A 0.125% change in interest rates under the RBL Facility and senior secured term loan would change pro forma interest expense by approximately $1.0 million for each period.

(2) Represents the estimated amortization of deferred financing fees, which are amortized over 5 years for the RBL Facility, 6 years for the senior secured term loan, 7 years for the senior secured notes and 8 years for the senior notes, and the amortization of the 1% original issue discount on the senior secured term loan over 6 years.

(3) Represents commitment fees of 0.375% on the estimated unused balance of the RBL Facility.

(4) Represents interest expense to be capitalized based on the weighted average borrowing rate and costs related to the unproven oil and gas properties being developed.

(5) Includes historical interest expense due to affiliates of approximately $3.0 million for the year ended December 31, 2011.

(g) Reflects an adjustment for EP Energy Corporation’s change in tax status from a taxable entity to a non-taxable entity leaving only current tax benefits associated with our international operations.

(h) Reflects the reclassification of activity with El Paso Corporation from affiliate to third‑party.

(i) Lease operating expenses and general and administrative expenses were presented in the aggregate as “operation and maintenance” in the historical audited financial statements included elsewhere herein.

**SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA**

The following table sets forth selected historical financial and other data for the periods and as of the dates indicated for EP Energy LLC (the “Successor” and formerly known as Everest Acquisition LLC) and EP Energy Global LLC (the “Predecessor” and formerly known as EP Energy Corporation and EP Energy, L.L.C.). See “Presentation of Financial Information.” We have derived the consolidated statement of income and statement of cash flows data for the period from January 1, 2012 to May 24, 2012, and the six months ended June 30, 2011, from EP Energy Corporation’s condensed unaudited consolidated financial statements included elsewhere in this prospectus. We have derived the consolidated statement of income and statement of cash flows data for the period from March 23, 2012 (inception) to June 30, 2012 and the consolidated balance sheet data as of June 30, 2012 from EP Energy LLC’s condensed unaudited consolidated financial statements included elsewhere in this prospectus. We have derived the consolidated statement of income and cash flows data for the years ended December 31, 2011, 2010 and 2009 and the consolidated balance sheet data as of December 31, 2011 and 2010 from EP Energy Corporation’s audited consolidated financial statements included elsewhere in this prospectus. The consolidated statements of income and cash flows data for the years ended December 31, 2009 and 2008 and the consolidated balance sheet data as of December 31, 2009, 2008 and 2007 have been derived from the audited consolidated financial statements of EP Energy Corporation, which are not included in this prospectus.

The following selected historical financial data should be read in conjunction with the information included under the heading “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our audited consolidated financial statements and the related notes included elsewhere in this prospectus.

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | **Successor** | **Predecessor** | | | | | | |
|  | **March 23 (inception) to June 30,** | **January 1, to May 24,** | **Six Months ended June 30,** | **Year ended December 31,** | | | | |
|  | **2012** | **2012** | **2011** | **2011** | **2010** | **2009** | **2008** | **2007** |
|  |  | **(dollars in millions)** | | | | | | |
| **Statement of income data** |  |  |  |  |  |  |  |  |
| Operating revenues: |  |  |  |  |  |  |  |  |
| Third parties | $143 | $470 | $439 | $948 | $634 | $552 | $1,078 | $1,093 |
| Affiliates | — | 143 | 322 | 634 | 746 | 545 | 1,423 | 1,169 |
| Realized and unrealized gains on financial derivatives(1) | 57 | 365 | 24 | 284 | 390 | 687 | 196 | — |
| Other | — | — | — | 1 | 19 | 44 | 65 | 38 |
| Total operating revenues | 200 | 978 | 785 | 1,867 | 1,789 | 1,828 | 2,762 | 2,300 |
| Operating expenses: |  |  |  |  |  |  |  |  |
| Cost of products | — | — | — | — | 15 | 31 | 38 | 20 |
| Transportation costs | 14 | 45 | 38 | 85 | 73 | 66 | 79 | 72 |
| Lease operating expenses(2) | 21 | 96 | 100 | 217 | 193 | 197 | 244 | 254 |
| General and administrative expenses(2) | 209 | 75 | 98 | 201 | 190 | 195 | 160 | 185 |
| Depreciation, depletion and amortization | 34 | 319 | 280 | 612 | 477 | 440 | 818 | 804 |
| Impairments/Ceiling test charges | 1 | 62 | — | 158 | 25 | 2,148 | 2,824 | — |
| Exploration expense | 6 | — | — | — | — | — | — | — |
| Taxes, other than income taxes | 12 | 45 | 49 | 91 | 85 | 68 | 132 | 103 |
| Total operating expenses | 297 | 642 | 565 | 1,364 | 1,058 | 3,145 | 4,295 | 1,438 |
| Operating income (loss) | (97) | 336 | 220 | 503 | 731 | (1,317) | (1,533) | 862 |
| Income (loss) from unconsolidated affiliates | (1) | (5) | (1) | (7) | (7) | (30) | (93) | 12 |
| Other income (expense) | 1 | (3) | — | (2) | 3 | (1) | 7 | 17 |
| Debt Extinguishment | — | — | — | — | — | — | — | (87) |
| Interest expense, net: |  |  |  |  |  |  |  |  |
| Third parties | (53) | (14) | (2) | (9) | (16) | (21) | (24) | (57) |
| Affiliates | — | — | (4) | (3) | (5) | (4) | (33) | (40) |
| Income (loss) before income taxes | (150) | 314 | 213 | 482 | 706 | (1,373) | (1,676) | 707 |
| Income tax expense (benefit) | — | 136 | 61 | 220 | 263 | (462) | (413) | 243 |
| Net income (loss) | $(150) | $178 | $152 | $262 | $443 | $(911) | $(1,263) | $464 |

(1) Includes less than $1 million for the successor period, $5 million for the predecessor periods from January 1 to May 24, 2012, $6 million for the six months ended June 30, 2011 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. During 2008, we removed the hedging designation on all of our commodity‑based derivative contracts related to our hedged oil and natural gas production volumes.

(2) Lease operating expenses and general and administrative expenses were presented in the aggregate as “operation and maintenance” in the historical predecessor audited financial statements of EP Energy Corporation for the years ended December 31, 2011, 2010, 2009, 2008 and 2007.

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Successor** | **Predecessor** | | | | |
|  | **As of June 30,** | **Year ended December 31,** | | | | |
|  | **2012** | **2011** | **2010** | **2009** | **2008** | **2007** |
|  | **(dollars in millions)** | | | | | |
| **Balance sheet data (at period end):** |  |  |  |  |  |  |
| Cash and cash equivalents | $55 | $25 | $74 | $183 | $102 | $114 |
| Total assets | 8,166 | 5,099 | 4,942 | 4,457 | 6,384 | 8,872 |
| Long-term debt | 4,243 | 851 | 301 | 835 | 915 | 751 |
| Members’/ Stockholder’s equity | 3,158 | 3,100 | 3,067 | 2,529 | 3,697 | 4,694 |
| **Other financial data:** |  |  |  |  |  |  |
| Capital expenditures(1) | $762 | $1,644 | $1,318 | $1,129 | $1,742 | $2,603 |

(1) Represents accrual based capital expenditures, including acquisitions capital, and excludes asset retirement obligation.

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | **Successor** | **Predecessor** | | | | | | |
|  | **March 23 (inception) to June 30,** | **January 1, to May 24,** | **Six Months ended June 30,** | **Year ended December 31,** | | | | |
|  | **2012** | **2012** | **2011** | **2011** | **2010** | **2009** | **2008** | **2007** |
|  |  | **(dollars in millions)** | | | | | | |
| **Statement of cash flows data:** |  |  |  |  |  |  |  |  |
| Net cash provided by (used in): |  |  |  |  |  |  |  |  |
| Operating activities | $(93) | $580 | $663 | $1,426 | $1,067 | $1,573 | $2,218 | $1,179 |
| Investing activities | (7,254) | (628) | (652) | (1,237) | (1,130) | (1,156) | (993) | (2,479) |
| Financing activities | 7,402 | 110 | (51) | (238) | (46) | (336) | (1,237) | 1,282 |
| **Other financial data:** |  |  |  |  |  |  |  |  |
| Ratio of earnings to fixed charges(2) | — | 18.0x | 19.6x | 21.1x | 25.3x | — | — | 6.4x |

(2) Earnings for the periods from March 23 to June 30, 2012 and for the years ended December 31, 2009 and 2008 were inadequate to cover fixed charges by $151 million, $1,305 million and $1,532 million, respectively. For purposes of computing these ratios, earnings means income (loss) before income taxes before (i) income or loss from equity investees, adjusted to reflect actual distributions from equity investments and (ii) fixed charges, less (a) capitalized interest. Fixed charges means the sum of the following: (i) interest costs, not including interest on tax liabilities which is included in income tax expense on our income statement; (ii) amortization of debt costs; and (iii) that portion of rental expense which we believe represents an interest factor.

**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 information under the headings “Risk Factors,” “Selected Historical Consolidated Financial Data” and “Business” and the financial statements and the accompanying footnotes included in this prospectus. This discussion contains forward‑looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the “Risk Factors” section of this registration statement. Actual results may differ materially from those contained in any forward‑looking statements. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to “we,” “our,” “us” and “the Company” refer to both EP Energy LLC (the Issuer) and EP Energy Global LLC (the “Predecessor” for accounting purposes), and each of its consolidated subsidiaries.

**Overview**

We are one of North America’s leading independent oil and natural gas producers. We have a large and diverse base of producing assets that provides cash flow to fund the development of our key programs, which at this time are primarily oil-focused. Over the last several years, we have high-graded our future drilling inventory by establishing large acreage positions with repeatable drilling opportunities and more favorable return characteristics. As a result, we have a strategic presence in well‑known oil resource areas, including the Eagle Ford Shale, the Altamont Field, the Wolfcamp Shale and South Louisiana Wilcox. Our large and diverse producing gas assets include our Haynesville Shale position, substantially all of which is held by production, which gives us a significant presence in unconventional natural gas. We also have a small international presence in Brazil and prior to selling our interests in Egypt in July 2012, we had an international presence in that country. Over the past five years, our strategy has been to focus on areas that offer repeatable drilling programs, enabling us to reduce development costs, and to grow our asset base and inventory size. We have consistently improved the quality and number of our drilling opportunities.

In June of 2012, we realigned our divisions based on our capital spending activities. The areas previously reported in the Western division will be reported under our Central division. In addition, Eagle Ford will be treated as a separate division. Prior to June 2012, we operated through three divisions: Central, Western and Southern. Domestically, we operate through three divisions: Central, Eagle Ford and Southern. The Central division includes operations in east Texas, Louisiana, Alabama, Indiana (Indiana assets sold in July 2012), eastern Oklahoma, in the Uintah Basin in Utah and the Raton Basin in New Mexico and Colorado. Our Eagle Ford division includes operations in south Texas. Our Southern division is located along the Gulf Coast, south and west areas of Texas and the Gulf of Mexico (sold in July 2012). Our key programs include the Haynesville Shale in northwest Louisiana and east Texas, the Altamont Field in Utah, the Eagle Ford Shale in south Texas and the Wolfcamp Shale which is located in the Permian Basin of west Texas.

Below is a description of each key program which are further described in “Business”:

***Eagle Ford Shale.*** The Eagle Ford Shale provides the highest economic returns in our portfolio. We currently are running four rigs.

***Haynesville Shale.*** We operated approximately four rigs in the Haynesville Shale through 2011 and currently have no rigs running. Although we had a very efficient drilling program in the Haynesville Shale, we suspended the program at the end of the first quarter of 2012 due to low natural gas prices. We have released all rigs and redeployed the capital allocated to the Haynesville Shale to our oil programs.

***Altamont Field.*** In the Altamont Field, we are gaining operational efficiencies as we develop the field. We currently are running two rigs.

***Wolfcamp Shale.*** In our Wolfcamp Shale program, which we entered in 2009 and 2010, we are focused on optimizing our drilling, completion and artificial lift systems. We currently are running one rig.

***South Louisiana Wilcox.*** We are continuing to develop our emerging South Louisiana Wilcox play. This is a relatively new oil and NGL play that we have added to our drilling program. We are currently running one rig.

Internationally, our portfolio consists of producing fields along with exploration and development projects in offshore Brazil. Achieving success in our international programs in Brazil will require effective project management, strong partner relations and obtaining approvals from regulatory agencies. Previously we also had exploration activities in Egypt, but our interests were sold in June 2012.

We evaluate acquisition and growth opportunities that are focused on our core competencies and areas of competitive advantage. Strategic acquisitions can provide us greater opportunities to achieve our long-term goals by leveraging existing expertise in key operating areas, balancing our exposure to regions, basins and commodities, helping us to achieve risk-adjusted returns competitive with those available within our existing drilling programs and increasing our reserves.

Our exploration and production operations generate profits which are dependent on the prices for 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 the following factors:

• growing our oil and natural gas proved reserve base and production volumes through the successful execution of our drilling programs;

• finding and producing oil and natural gas at a reasonable cost; and

• managing price risks to optimize realized prices 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, the impacts of volatility in the financial and commodity markets, industry-wide changes in the cost of drilling and oilfield services which impact our daily production, operating and capital costs and our debt level and related interest costs. Additionally, we may be impacted by hurricanes and other weather events, or domestic or international regulatory issues or other 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 reduce the financial impact of downward commodity price movements.

**Results of Operations**

***Overview***

The historical financial results for the periods before and after the Acquisition, which closed on May 24, 2012, in the tables that follow have been presented separately in accordance with required GAAP presentation. Periods prior to May 24, 2012 are referred to as predecessor periods and those entities as the Predecessor, while periods after May 24, 2012 are referred to as successor periods and those entities as the Successor. Despite this separate GAAP presentation, the successor had no independent oil and gas operations prior to the acquisition and accordingly there were no operational exploration and production activities changed as a result of the acquisition of the Predecessor. Consequently, given the continuity of operations, when assessing variance analysis of our historical results of operations and financial performance as well as in reviewing our operating statistics (e.g. volumes and per unit metrics and costs) in the tables and discussion that follows, we have evaluated the six month period ended June 30, 2011 of the predecessor to the combined six month period ended June 30, 2012. This presentation represents a combined analysis of the pre-acquisition results of operations of the Predecessor and the post‑acquisition results of operations of the Successor in 2012. We believe that reflecting the combined information and analysis, while non‑GAAP, facilitates the most meaningful comparison and understanding of our operating performance in 2012 over the same period in the prior year.

In connection with the Acquisition Transactions and Refinancing Transactions, we incurred $4,250 million of principal amount of total indebtedness outstanding. We have the ability to incur approximately $1.25 billion of additional indebtedness under the RBL Facility. We are and will continue to be highly leveraged and have significant additional liquidity requirements. As a result, we expect that our interest expense will be significantly higher in future periods than we have experienced in the predecessor periods. See “Unaudited Pro Forma Condensed Consolidated Financial Data” and “—Liquidity and Capital Resources” for more information regarding the pro forma effect of the Acquisition Transactions and Refinancing Transactions. Additionally, the financial results for the successor period presented includes the application of purchase accounting and the application of the successful efforts method of accounting for oil and natural gas properties. As a result, trends and results in future periods may look different than those that existed prior to the acquisition and under the full cost method of accounting. See “Risk Factors,” “Unaudited Pro Forma Condensed Consolidated Financial Data” and “—Liquidity and Capital Resources.”

***Significant Operational Factors***

***Production.*** Below is an analysis of our production by division for the six months ended June 30 and three years ended December 31:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **Six Months ended June 30,** | | **Years ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
|  | **(MMcfe/d)** | | | | |
| United States |  |  |  |  |  |
| Central | 603 | 569 | 576 | 498 | 423 |
| Eagle Ford | 91 | 20 | 40 | 6 | — |
| Southern | 120 | 137 | 127 | 183 | 256 |
| International |  |  |  |  |  |
| Brazil | 36 | 34 | 34 | 33 | 12 |
| Total consolidated | 850 | 760 | 777 | 720 | 691 |
| Unconsolidated affiliate | 56 | 62 | 61 | 62 | 72 |
| Total combined | 906 | 822 | 838 | 782 | 763 |

***Volumes.*** Our volumes by commodity for the six months ended June 30 and three years ended December 31 were as follows:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **Six Months ended June 30,** | | **Years ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
| Natural Gas (MMcf/d) |  |  |  |  |  |
| Consolidated volumes | 686 | 658 | 661 | 618 | 599 |
| Unconsolidated affiliate volumes | 43 | 47 | 46 | 47 | 54 |
| Total Combined | 729 | 705 | 707 | 665 | 653 |
| Oil and condensate (MBbls/d) |  |  |  |  |  |
| Consolidated volumes | 23 | 14 | 16 | 13 | 11 |
| Unconsolidated affiliate volumes | 1 | 1 | 1 | 1 | 1 |
| Total Combined | 24 | 15 | 17 | 14 | 12 |
| NGL (MBbls/d) |  |  |  |  |  |
| Consolidated volumes | 5 | 3 | 3 | 4 | 5 |
| Unconsolidated affiliate volumes | 1 | 2 | 1 | 2 | 2 |
| Total Combined | 6 | 5 | 4 | 6 | 7 |

*Central division*—Our 2012 Central division production volumes increased 34 MMcfe/d for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 primarily as a result of our drilling program in the Haynesville Shale and our successful drilling programs in our Altamont and Raton Basin areas. At June 30, 2012, we had 66 net operated wells in the Haynesville Shale and our total production was approximately 317 MMcfe/d. Although we had a very efficient capital program in the Haynesville Shale, we suspended the program at the end of the first quarter of 2012 due to low natural gas prices. We released all rigs and redeployed the capital allocated to the Haynesville Shale to our oil programs. In addition, a relatively new oil play, the South Louisiana Wilcox program had 19 net operated wells with total oil and NGL production of approximately 2 MBbls/d for the six months ended June 30, 2012. As of June 30, 2012, we had 307 net operated wells in our Altamont Field with total oil production of approximately 7 MBbls/d.

*Eagle Ford division*—Our 2012 Eagle Ford division production volumes increased 71 MMcfe/d for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 due to our successful drilling program in the area. During the six months ended June 30, 2012, we drilled 36 additional wells in our Eagle Ford Shale for a total of 98 net operated wells. With a majority of our acreage located in the oil and liquids rich area of the Eagle Ford Shale, our total oil and NGL production was approximately 12 MBbls/d for the six months ended June 30, 2012, an increase of over 350 percent from the same period of last year.

*Southern division*—Our 2012 Southern division production volumes decreased 17 MMcfe/d for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 primarily due to natural declines and lower levels of drilling activity in the Texas Gulf Coast and Gulf of Mexico, partially offset by our successful drilling in the Wolfcamp Shale. In our Wolfcamp Shale area, we drilled 10 additional wells during 2012, for a total of 26 net operated wells. We sold our Gulf of Mexico assets in July 2012, which during the six months ended June 30, 2012, and twelve months ended December 31, 2011, had equivalent production of 45 MMcfe/d and 46 MMcfe/d, respectively.

*International*—Our 2012 production volumes in Brazil increased 2 MMcfe/d for the six months ended June 30, 2012 compared to the six months ended June 30, 2011 primarily due to a fourth well coming on line in August 2011 and an oil offloading in March and June of 2012 from our Camarupim Field. We are still awaiting a response on our appeal filed in 2011, for our environmental permit request concerning the Pinauna Field which was denied by the Brazilian environmental regulatory agency. In June of 2012, we sold all our interests in Egypt. The sale represents an exit from our Egyptian exploration activities.

*Cash Operating Costs and Adjusted Cash Operating Costs.* We monitor cash operating costs required to produce our oil and natural gas production volumes. Cash operating costs is a non-GAAP measure calculated on a per Mcfe basis and includes total operating expenses less depreciation, depletion and amortization expense, exploration expense, ceiling test and other impairment charges, transportation costs and cost of products. Adjusted cash operating costs is a non‑GAAP measure and is defined as cash operating costs less transition and restructuring costs and non-cash equity based compensation expense. Cash operating costs and adjusted cash operating costs per unit are a valuable measure of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies.

During the six months ended June 30, 2012, adjusted cash operating costs per unit decreased to $1.66/Mcfe as compared to $1.67/Mcfe during the same period in 2011, primarily due to higher production volumes offset by higher general and administrative costs and higher lease operating expenses.

The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs for the six months ended June 30:

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **Six Months ended June 30,** | | | |
|  | **2012** | | **2011** | |
|  | **Total** | **Per unit** | **Total** | **Per unit** |
|  | **(In millions, except per unit costs)** | | | |
| Total operating expenses | $939 | $6.07 | $565 | $4.11 |
| Depreciation, depletion and amortization | (353) | (2.28) | (280) | (2.04) |
| Transportation costs | (59) | (0.38) | (38) | (0.27) |
| Exploration expense | (6) | (0.04) | — | — |
| Ceiling test charges | (63) | (0.41) | — | — |
| Total cash operating costs and per-unit cash costs(1) | 458 | 2.96 | 247 | 1.80 |
| Transition/restructurings costs and non-cash equity based compensation  expense(2) | (202) | (1.30) | (17) | (0.13) |
| Total adjusted cash operating costs and adjusted per-unit cash costs(1) | $256 | $1.66 | $230 | $1.67 |
| Total equivalent volumes (MMcfe)(1) | 154,818 |  | 137,543 |  |

(1) Excludes volumes and costs associated with Four Star.

(2) Total amount in 2012 includes $183 million for transition and restructuring costs associated with the acquisition, $3 million of advisory fees and $16 million of non‑cash equity‑based compensation expense. Total amount in 2011 includes $6 million of restructuring costs associated with the closure of our Denver office and $11 million of non‑cash equity‑based compensation expense.

The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs for the three years ended December 31:

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Years ended December 31,** | | | | | |
|  | **2011** | | **2010** | | **2009** | |
|  | **Total** | **Per unit** | **Total** | **Per unit** | **Total** | **Per unit** |
|  | **(dollars in millions, except per unit costs)** | | | | | |
| Total operating expenses | $1,364 | $4.81 | $1,058 | $4.03 | $3,145 | $12.46 |
| Depreciation, depletion and amortization | (612) | (2.16) | (477) | (1.82) | (440) | (1.74) |
| Transportation costs | (85) | (0.30) | (73) | (0.28) | (66) | (0.26) |
| Cost of products | — | — | (15) | (0.05) | (31) | (0.13) |
| Ceiling test charges | (152) | (0.54) | (25) | (0.10) | (2,123) | (8.41) |
| Impairments | (6) | (0.02) | — | — | (25) | (0.10) |
| Total cash operating costs and per-unit cash costs(1) | 509 | 1.79 | 468 | 1.78 | 460 | 1.82 |
| Restructuring costs and non-cash equity based compensation expense | (27) | (0.10) | (18) | (0.07) | (26) | (0.10) |
| Total adjusted cash operating costs and adjusted per-unit cash costs(1) | 482 | 1.69 | 450 | 1.71 | 434 | 1.72 |
| Total equivalent volumes (MMcfe)(1) | 283,696 |  | 262,631 |  | 252,432 |  |

(1) Excludes volumes and costs associated with Four Star.

*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 key asset areas. 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 in our key asset areas 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 per Mcfe: | Total oil and 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 “Financial Statements and Supplementary Data—Supplemental Oil and Natural Gas Operations.”

(2) Total oil and natural gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations. Amounts are derived directly from the table presented in “Financial Statements and Supplementary Data—Supplemental Oil and Natural Gas Operations.”

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

The exploration for and the acquisition and development of oil and natural gas reserves is inherently uncertain as further discussed in “Risk Factors—Risks Related to Our Business and Industry.” One of these risks and uncertainties is our ability to spend sufficient capital to increase our reserves. While we currently expect to spend such amounts in the future, there are no assurances as to the timing and magnitude of these expenditures or the classification of the proved reserves as developed or undeveloped. At December 31, 2011, proved developed reserves represent approximately 50% 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.

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

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Including Price Revisions** | | | **Excluding Price Revisions** | | |
|  | **2011** | **2010** | **2009** | **2011** | **2010** | **2009** |
|  | **($/Mcfe)** | | | **($/Mcfe)** | | |
| **Reserve Replacement Ratios** |  |  |  |  |  |  |
| ***Domestic*** |  |  |  |  |  |  |
| Including acquisitions | 416% | 370% | 188% | 418% | 306% | 220% |
| Excluding acquisitions | 416 | 353 | 162 | 418 | 289 | 195 |
| ***Worldwide*** |  |  |  |  |  |  |
| Including acquisitions | 400 | 347 | 212 | 401 | 284 | 245 |
| Excluding acquisitions | 400 | 331 | 187 | 401 | 268 | 220 |
| **Reserve Replacement Costs(1)** |  |  |  |  |  |  |
| ***Domestic*** |  |  |  |  |  |  |
| Including acquisitions | $1.42 | $1.29 | $1.84 | $1.41 | $1.56 | $1.57 |
| Excluding acquisitions | 1.42 | 1.29 | 1.91 | 1.41 | 1.58 | 1.59 |
| ***Worldwide*** |  |  |  |  |  |  |
| Including acquisitions | 1.43 | 1.40 | 2.04 | 1.43 | 1.72 | 1.76 |
| Excluding acquisitions | 1.43 | 1.41 | 2.13 | 1.43 | 1.75 | 1.81 |

(1) Only proved property acquisition costs are excluded from these calculations. Leasehold or unproved acquisitions costs are included in all calculations.

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

|  |  |  |
| --- | --- | --- |
|  | **Three Years Ended December 31, 2011** | |
|  | **Including Price Revisions** | **Excluding Price Revisions** |
|  | **($/Mcfe)** | |
| **Reserve Replacement Costs** |  |  |
| ***Domestic*** |  |  |
| Including acquisitions | $1.45 | $1.49 |
| Excluding acquisitions | 1.45 | 1.50 |
| ***Worldwide*** |  |  |
| Including acquisitions | 1.55 | 1.60 |
| Excluding acquisitions | 1.56 | 1.61 |

*Capital Expenditures.* Our oil and gas capital expenditures were as follows for the six months ended June 30 and three years ended December 31:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **Six Months ended June 30,** | | **Years ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
|  | **(in millions)** | | | | |
| Total oil and gas capital costs, excluding proved property acquisitions | $757 | $727 | $1,624 | $1,231 | $1,004 |
| Proved property acquisitions | — | 1 | — | 51 | 87 |
| Total oil and gas capital costs, including acquisitions(1) | 757 | 728 | 1,624 | 1,282 | 1,091 |
| Non-oil and gas capital costs | 5 | 8 | 20 | 36 | 38 |
| Total capital expenditures | $762 | $736 | $1,644 | $1,318 | $1,129 |

(1) Total oil and gas capital costs include the costs of development, exploration and property acquisition activities conducted to add reserves and exclude asset retirement obligations.

Capital expenditures for the six months ended June 30, 2012 and rig count by key program as of June 30, 2012 were:

|  |  |  |
| --- | --- | --- |
|  | **Capital Expenditures (In millions)** | **Rig Count** |
| Eagle Ford | $421 | 4 |
| Haynesville | 89 | — |
| Altamont | 77 | 2 |
| Wolfcamp | 111 | 1 |
| South Louisiana Wilcox | 55 | 1 |
| Other, including International | 9 | — |
| Total capital expenditures | $762 | 8 |

*Price Risk Management Activities*

We enter into derivative contracts on our oil and natural gas production primarily to stabilize cash flows and reduce the risk and financial impact of downward commodity price movements on commodity sales. Because we apply mark-to-market accounting on our financial derivative contracts and because we do not hedge all of our price risks, this strategy only partially reduces our commodity price exposure. 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. During the first six months of 2012, approximately 75 percent of our natural gas production and 90 percent of our crude oil production were hedged and settled at average floor prices of $4.85 per MMBtu and $95.22 per barrel, respectively.

The following table reflects the contracted volumes and the minimum, maximum and average prices we will receive under our derivative contracts as of June 30, 2012.

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | **2012** | | **2013** | | **2014** | | **2015** | |
|  | **Volumes(1)** | **Average Price(1)** | **Volumes(1)** | **Average Price(1)** | **Volumes(1)** | **Average Price(1)** | **Volumes(1)** | **Average Price(1)** |
| *Natural Gas* |  |  |  |  |  |  |  |  |
| Fixed Price Swaps | 103 | $4.47 | 138 | $3.54 | 52 | $3.92 | 11 | $4.01 |
| *Oil* |  |  |  |  |  |  |  |  |
| Fixed Price Swaps | 1,654 | $105.12 | 8,225 | $104.72 | 8,760 | $98.64 | 5,502 | $95.42 |
| Ceilings | 736 | $95.00 | — | $— | 1,095 | $100.00 | 1,095 | $100.00 |
| Three Way Collars Ceiling | 2,898 | $114.16 | 3,741 | $108.09 | — | $— | — | $— |
| Three Way Collars Floors(2) | 2,898 | $92.54 | 3,741 | $91.22 | — | $— | — | $— |

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

(2) If market prices settle at or below $67.54 and $69.15 for the years 2012 and 2013, respectively, our three-way collars‑floors effectively “lock-in” a cash settlement of the market price plus $25.00 per Bbl for 2012 and plus $22.07 per Bbl for 2013.

In July and August of 2012, we added 730 MBbls of oil fixed price swaps at an average price of $90.00 per barrel and 1,829 MBbls of costless three-way oil collars for our anticipated 2013 oil production. For these collars, the transactions effectively provide an average ceiling price of $102.26 per barrel and an average floor price of $95.00 per barrel unless oil prices drop below $75.00 per barrel. If oil prices drop below $75.00 per barrel, the transactions effectively lock-in a cash settlement of the market price plus $20.00 per barrel. We also entered into 14 TBtu at an average price of $3.61 per MMBtu and 11 TBtu at an average price of $4.01 per MMBtu of natural gas fixed price swaps at for our anticipated 2013 and 2015 natural gas production, respectively.

***Operating Results***

The information below provides the financial results for the Successor from March 23 (inception) to June 30 and for the Predecessor from January 1 to May 24 and for the six months ended June 30 and the three years ended December 31:

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Successor** | **Predecessor** | | | | |
|  | **March 23 (inception) to June 30,** | **January 1 to May 24,** | **Six Months ended June 30,** | **Years ended December 31,** | | |
|  | **2012** | **2012** | **2011** | **2011** | **2010** | **2009** |
|  |  | **(dollars in millions)** | | | | |
| *Physical sales*: |  |  |  |  |  |  |
| Oil and condensate | $77 | $322 | $236 | $552 | $346 | $214 |
| Natural gas | 61 | 262 | 497 | 973 | 974 | 830 |
| NGL | 5 | 29 | 28 | 57 | 60 | 53 |
| Total physical sales | 143 | 613 | 761 | 1,582 | 1,380 | 1,097 |
| Realized and unrealized gains on financial derivatives(1) | 57 | 365 | 24 | 284 | 390 | 687 |
| Other revenues | — | — | — | 1 | 19 | 44 |
| Total operating revenues | 200 | 978 | 785 | 1,867 | 1,789 | 1,828 |
| *Operating Expenses*: |  |  |  |  |  |  |
| Cost of products | — | — | — | — | 15 | 31 |
| Transportation costs | 14 | 45 | 38 | 85 | 73 | 66 |
| Production costs(2) | 32 | 136 | 143 | 298 | 264 | 252 |
| Depreciation, depletion and amortization | 34 | 319 | 280 | 612 | 477 | 440 |
| General and administrative expenses | 209 | 75 | 98 | 201 | 190 | 195 |
| Exploration expenses | 6 | — | — | — | — | — |
| Impairments/Ceiling test charges | 1 | 62 | — | 158 | 25 | 2,148 |
| Other | 1 | 5 | 6 | 10 | 14 | 13 |
| Total operating expenses | 297 | 642 | 565 | 1,364 | 1,058 | 3,145 |
| Operating income (loss) | (97) | 336 | 220 | 503 | 731 | (1,317) |
| Loss from unconsolidated affiliates | (1) | (5) | (1) | (7) | (7) | (30) |
| Other income (expense) | 1 | (3) | — | (2) | 3 | (1) |
| Interest expense | (53) | (14) | (6) | (12) | (21) | (25) |
| (Loss) income before income taxes | (150) | 314 | 213 | 482 | 706 | (1,373) |
| Income taxes (benefit) | — | 136 | 61 | 220 | 263 | (462) |
| Net (loss) income | $(150) | $178 | $152 | $262 | $443 | $(911) |

(1) Includes less than $1 million for the successor period and $5 million for the predecessor periods from January 1, 2012 to May 24, 2012 and $6 million for the six months ended June 30, 2011 and $11 million, $11 million and $406 million for the years ended December 31, 2011, 2010 and 2009, reclassified from accumulated other comprehensive income associated with accounting hedges. During 2008, we removed the hedging designation on all our commodity‑based derivative contracts related to our hedged oil and natural gas production volumes.

(2) Includes domestic lease operating expenses of $16 million for the successor period and $80 million for the predecessor periods from January 1, 2012 to May 24, 2012 and $80 million for the six months ended June 30, 2011 for the six months ended June 30, 2012 and 2011 and $176 million, $156 million and $175 million, respectively for the years ended December 31, 2011, 2010 and 2009.

The table below provides additional detail of our volumes, prices, and costs per unit. We present (i) average realized prices based on physical sales of natural gas, oil and condensate and NGL as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements. Our average realized prices, including financial derivative settlements, reflect cash received and/or paid during the period on settled financial derivatives based on the period the contracted settlements were originally scheduled to occur; however, these prices do not reflect the impact of any associated premiums paid to enter into certain of our derivative contracts.

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **Six months ended June 30,** | | **Years ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
| *Volumes*: |  |  |  |  |  |
| Oil and condensate |  |  |  |  |  |
| Consolidated volumes (MBbls) | 4,138 | 2,543 | 6,034 | 4,747 | 4,078 |
| Unconsolidated affiliate volumes (MBbls) | 142 | 159 | 306 | 364 | 419 |
| Natural gas |  |  |  |  |  |
| Consolidated volumes (MMcf) | 124,819 | 119,052 | 241,083 | 225,611 | 218,544 |
| Unconsolidated affiliate volumes (MMcf) | 7,848 | 8,554 | 16,881 | 17,165 | 19,557 |
| NGL |  |  |  |  |  |
| Consolidated volumes (MBbls) | 862 | 538 | 1,068 | 1,423 | 1,570 |
| Unconsolidated affiliate volumes (MBbls) | 237 | 280 | 556 | 573 | 678 |
| Equivalent volumes |  |  |  |  |  |
| Consolidated MMcfe | 154,818 | 137,543 | 283,696 | 262,631 | 252,432 |
| Unconsolidated affiliate MMcfe | 10,126 | 11,186 | 22,052 | 22,787 | 26,139 |
| Total combined MMcfe | 164,944 | 148,729 | 305,748 | 285,418 | 278,571 |
| Consolidated MMcfe/d | 850 | 760 | 777 | 720 | 691 |
| Unconsolidated affiliate MMcfe/d | 56 | 62 | 61 | 62 | 72 |
| Total Combined MMcfe/d | 906 | 822 | 838 | 782 | 763 |
| *Consolidated prices and costs per unit:* |  |  |  |  |  |
| Oil and condensate |  |  |  |  |  |
| Average realized price on physical sales ($/Bbl) | $96.32 | $92.74 | $91.40 | $72.83 | $52.48 |
| Average realized price, including financial derivative settlements ($/Bbl)(1)(2) | 97.91 | 88.67 | 90.23 | 71.13 | 95.57 |
| Average transportation costs ($/Bbl) | 0.91 | 0.06 | 0.06 | 0.08 | 0.06 |
| Natural gas |  |  |  |  |  |
| Average realized price on physical sales ($/Mcf) | $2.59 | $4.18 | $4.04 | $4.32 | $3.80 |
| Average realized prices, including financial derivative settlements ($/Mcf)(1)(2) | 4.20 | 5.44 | 5.44 | 5.67 | 7.62 |
| Average transportation costs ($/Mcf) | 0.38 | 0.30 | 0.33 | 0.30 | 0.28 |
| NGL |  |  |  |  |  |
| Average realized price on physical sales ($/Bbl) | $39.89 | $52.41 | $53.50 | $42.38 | $33.75 |
| Average transportation costs ($/Bbl) | 6.57 | 4.88 | 3.83 | 3.16 | 2.61 |
| Production costs and other cash operating costs ($/Mcfe) |  |  |  |  |  |
| Average lease operating expenses | $0.75 | $0.73 | $0.77 | $0.73 | $0.78 |
| Average production taxes(3) | 0.33 | 0.31 | 0.28 | 0.27 | 0.22 |
| Average general and administrative expenses | 1.84 | 0.71 | 0.70 | 0.72 | 0.77 |
| Average taxes, other than production and income taxes | 0.04 | 0.05 | 0.04 | 0.06 | 0.05 |
| Total cash operating costs(4) | $2.96 | $1.80 | $1.79 | $1.78 | $1.82 |
| Depreciation, depletion and amortization ($/Mcfe)(5) | $2.29 | $2.04 | $2.16 | $1.82 | $1.74 |

(1) We had no cash premiums related to oil and natural gas derivatives settled during the six months ended June 30, 2012. Premiums related to natural gas derivatives settled during the six months ended June 30, 2011 were approximately $12 million. Had we included these premiums in our natural gas average realized prices in 2011, our realized price, including financial derivative settlements, would have decreased by $0.10/Mcf for the six months ended June 30, 2011. We had no cash premiums related to oil derivatives settled during the six months ended June 30, 2011. We had no cash premiums related to oil derivatives settled during the years ended December 31, 2011, 2010 and 2009. Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Premiums paid related to natural gas derivatives settled during the year ended December 31, 2011 were $23 million. Had we included these premiums in our natural gas average realized prices in 2010 and 2011, our realized price, including financial derivative settlements, would have decreased by $0.70/Mcf and $0.10/Mcf for the years ended December 31, 2010 and 2011.

(2) The six months ended June 30, 2012 and 2011 include approximately $201 million and $150 million, respectively, of cash receipts on settlements related to natural gas derivative contracts and approximately $7 million and $(10) million of cash receipts and cash paid, respectively, on settlements related to crude oil derivative contracts. The years ended December 31, 2011, 2010 and 2009 include approximately $338 million, $306 million and $834 million, respectively, of cash receipts for settlements of natural gas derivative contracts. The years ended December 31, 2010 and 2011, include approximately $8 million and $7 million, respectively, of cash paid for the settlement of crude oil derivative contracts. Additionally, the year ended December 31, 2009, includes approximately $176 million of cash receipts for the settlement of crude oil derivative contracts.

(3) Production taxes include ad valorem and severance taxes.

(4) Total adjusted cash operating costs per unit for each period were $1.66/Mcfe, $1.67/Mcfe, $1.69/Mcfe, $1.71/Mcfe and $1.72/Mcfe. See Cash Operating Costs and Adjusted Cash Operating costs section of MD&A for a reconciliation.

(5) Includes $0.05 per Mcfe and $0.06 per Mcfe for the six months ended June 30, 2012 and 2011, respectively, and $0.05 per Mcfe for the year ended December 31, 2011 and $0.06 per Mcfe for both years ended December 31, 2010 and 2009 related to accretion expense on asset retirement obligations.

***Six Months Ended June 30, 2012 Compared with Six Months Ended June 30, 2011***

Our net income for the six months ended June 30, 2012 decreased $124 million as compared to the same period in 2011. The discussion below reflects variances in our financial results for the six months ended June 30, 2012 as compared with the same period in 2011.

*Physical sales.* Physical sales represent accrual‑based commodity sales transactions with customers. For the six months ended June 30, 2012, physical sales were $756 million compared to $761 million for the six months ended June 30, 2011. The overall decrease of $5 million, or 1 percent, was a result of the (i) favorable impact of $148 million, $24 million and $17 million related to higher production volumes of oil and condensate, natural gas and NGL, respectively, (ii) a favorable impact of $15 million related to the increase in realized oil and condensate prices and (iii) the unfavorable impact of $198 million and $11 million related to lower realized prices for natural gas and NGL, respectively. The increase in oil production is primarily attributable to our Eagle Ford and Altamont key programs which are up 9 MBbls/d year over year.

*Realized and unrealized gains on financial derivatives.* Realized and unrealized gains for the six months ended June 30, 2012 were $422 million compared to $24 million for the six months ended June 30, 2011. The increase of $398 million was due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

*Transportation costs.* Transportation costs for the six months ended June 30, 2012 were $59 million compared to $38 million for the six months ended June 30, 2011. This increase of $21 million, or 55 percent, was due primarily to new transportation contracts entered into in 2012.

*Production costs.* Production costs for the six months ended June 30, 2012 were $168 million compared to $143 million for the six months ended June 30, 2011. This increase of $25 million, or 17 percent, was due primarily to an increase of $17 million in lease operating expenses and an increase of $8 million in production taxes. Lease operating expenses are attributable to increased water disposal costs in our Eagle Ford and Central divisions and higher equipment, contract labor and chemical costs in our Eagle Ford division. Production taxes increased primarily due to higher production volumes.

*Depreciation, depletion and amortization expense.* Depreciation, depletion and amortization expense for the six months ended June 30, 2012 was $353 million compared to $280 million for the six months ended June 30, 2011. The increase of $73 million, or 26 percent, was a result of an increase of $39 million due to a higher depletion rate and an increase of $34 million due to higher production volumes compared to the same period in 2011. During the first half of 2012, we experienced an expected upward trend in our depletion rate relative to prior periods as we focused our capital expenditures on developing key oil programs and as we moved away from significant ceiling test charges in 2009. Due to the application of the successful efforts method of accounting for oil and natural gas properties after the acquisition, we expect our depletion rate will decrease during the second half of 2012 compared to the first six months of 2012.

*General and administrative expenses.* General and administrative expenses for the six months ended June 30, 2012 were $284 million compared to $98 million for the six months ended June 30, 2011. The increase of $186 million, or 190 percent, is primarily due to $186 million of transition and restructuring costs associated with the acquisition.

*Exploration expense.* Exploration expense for the six months ended June 30, 2012 was $6 million due to applying the successful efforts method of recording exploration costs compared to applying the full cost method prior to the acquisition.

*Impairments/Ceiling test charges.* Under the full cost method of accounting, each quarter we were required to evaluate our capitalized costs in each of our full cost pools. During the six months ended June 30, 2012 we recorded a non-cash charge of approximately $62 million as a result of our decision to end exploration and development activities in Egypt. In June of 2012, we sold all our interests in Egypt. No full cost ceiling test charges were recorded during the six months ended June 30, 2011. Additionally, no impairments were recorded of oil and natural gas properties in the successor period through June 30, 2012. Due to current natural gas prices, the fair value of our oil and natural gas properties could decline in the future and we may be required to record an impairment to the carrying value.

***Year Ended December 31, 2011 Compared to Year Ended December 31, 2010***

Our net income for 2011 was $262 million compared to net income for 2010 of $443 million. This represents a decrease of $181 million or 41% as compared to 2010. The discussion below reflects variances in our financial results in 2011 as compared to 2010.

*Physical sales.* Physical sales represent accrual‑based commodity sales transactions with customers. Physical sales for 2011 were $1,582 million compared to $1,380 million for 2010. This represents an increase of $202 million or 15% for the twelve months ending December 31, 2011 as compared to the twelve months ended December 31, 2010. Of this increase, $112 million and $12 million were related to the change in realized prices for oil and condensate and NGL, respectively, and $94 million and $67 million were related to an increase in production volumes of oil and condensate and natural gas sold, respectively. These increases were partially offset by decreases of $68 million related to a reduction in realized prices for natural gas and $15 million related to a decrease in production volumes of NGL sold. The higher volumes are due to our focus on our key programs in the Haynesville and Eagle Ford shales.

*Realized and unrealized gains on financial derivatives.* Realized and unrealized gains for 2011 were $284 million compared to $390 million for 2010. This represents a decrease of $106 million or 27% for the twelve months ending December 31, 2011 as compared to the twelve months ended December 31, 2010. This decrease was due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

*Production costs.* Production costs for 2011 were $298 million compared to $264 million for 2010. This represents an increase of $34 million or 13% for the twelve months ending December 31, 2011 as compared to the twelve months ended December 31, 2010. This increase was due primarily to an increase of $24 million in lease operating expenses and an increase of $10 million in production taxes. Lease operating expenses increased due to higher maintenance, repair and power costs in our Central division, temporary higher costs in our Southern division due to early well testing and higher expenses in our International division. Production taxes increased primarily due to higher volumes.

*Depreciation, depletion and amortization expense.* Depreciation, depletion and amortization expense for 2011 was $612 million compared to $477 million for 2010. This represents an increase of $135 million or 28% for the twelve months ending December 31, 2011 as compared to the twelve months ended December 31, 2010. This increase was a result of an increase of $98 million due to a higher depletion rate and an increase of $37 million related to higher production volumes compared to the same period in 2010. Our depreciation, depletion and amortization rate increased in 2011 as we focused our capital on oil programs.

*General and administrative expenses.* General and administrative expenses for 2011 were $201 million compared to $190 million for 2010. This represents an increase of $11 million or 6% for the twelve months ending December 31, 2011 as compared to the twelve months ended December 31, 2010. This increase was due primarily to an increase of $5 million in severance costs related to an office closure and an increase of $6 million related to employee benefit costs.

*Impairments/Ceiling test charges.* We recorded a non-cash ceiling test charge in 2011 of $152 million compared to $25 million in 2010. This represents an increase of $127 million or 508% as compared to the year ended December 31, 2010. The 2011 ceiling test charge was driven by the release of costs into the Brazilian full cost pool substantially due to the denial of a necessary environmental permit on our Pinauna project as well as the completion of our evaluation of certain exploratory wells drilled in 2009 and 2010. We have filed an appeal with regard to the denial of the permit and are awaiting a response. During the year ended December 31, 2010, we recorded non-cash ceiling test charges of $25 million related to our Egyptian full cost pool as a result of acreage relinquishments in South Mariut and South Alamein and a dry hole drilled in the Tanta block.

*Other.* Our equity losses from Four Star for 2011 were $7 million, which is consistent with our 2010 equity losses. In addition, the fair value of our investment in Four Star could decline as a result of lower natural gas prices, and we may be required to record an impairment of the carrying value in the future.

***Year Ended December 31, 2010 Compared to Year Ended December 31, 2009***

Our net income for 2010 was $443 million compared to net loss for 2009 of $911 million. This represents an increase of $1,354 million or 148% as compared to 2009. The table below shows our operating revenue variances in our financial results in 2010 as compared to 2009:

*Physical sales.* Physical sales represent accrual‑based commodity sales transactions with customers. Physical sales for 2010 were $1,380 million compared to $1,097 million for 2009. This represents an increase of $283 million or 26% for the twelve months ending December 31, 2010 as compared to the twelve months ended December 31, 2009. Of this increase $117 million, $97 million and $12 million were related to the change in realized prices, for natural gas, oil and condensate and NGL, respectively, and $35 million and $27 million were related to an increase in production volumes of oil and condensate and natural gas sold, respectively. These increases were partially offset by a decrease of $5 million related to a reduction in production volumes of NGL sold. During the year ended December 31, 2010, we also benefited from an increase in production volumes in our Central division and in Brazil.

*Realized and unrealized gains on financial derivatives.* Realized and unrealized gains on financial derivatives for 2010 were $390 million compared to $687 million for 2009. This represents a decrease of $297 million or 43% for the twelve months ending December 31, 2010 as compared to the twelve months ended December 31, 2009. This decrease was due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts.

*Production costs.* Production costs for 2010 were $264 million compared to $252 million for 2009. This represents an increase of $12 million or 5% for the twelve months ending December 31, 2010 as compared to the twelve months ended December 31, 2009. This increase was due primarily to an increase of $16 million in production taxes, which resulted from higher production volumes.

*Depreciation, depletion and amortization expense.* Depreciation, depletion and amortization expense for 2010 was $477 million compared to $440 million for 2009. This represents an increase of $37 million or 8% for the twelve months ending December 31, 2010 as compared to the twelve months ended December 31, 2009. This increase was the result of an increase of $20 million due to a higher depletion rate and an increase of $17 million related to higher production volumes. The depletion rate for the year ended December 31, 2009 was impacted largely by the ceiling test charges recorded in the first quarter of 2009.

*General and administrative expenses.* General and administrative expenses for 2010 were $190 million compared to $195 million for 2009. This represents a decrease of $5 million or 3% for the twelve months ending December 31, 2010 as compared to the twelve months ended December 31, 2009. This was due primarily to a decrease related to payroll and administrative costs to support the business following reorganizations in 2009.

*Impairments/Ceiling test charges.* We recorded a non-cash ceiling test charges in 2010 of $25 million related to our Egyptian full cost pool compared to a full cost ceiling test charge of $2,123 million in 2009. This represents a decrease of $2,098 million or 99% as compared to the year ended December 31, 2009. The non-cash ceiling test charge in 2010 to our Egyptian full cost pool was a result of contractual acreage relinquishments in our blocks, and a dry hole drilled in the Tanta block. During the year ended December 31, 2009, we recorded non-cash ceiling test charges of $2.1 billion related to our domestic and Brazilian full cost pools as a result of low oil and natural gas prices and to our Egyptian full cost pool as a result of dry hole costs.

*Other.* Our equity loss from Four Star for 2010 was $7 million compared to equity loss of $30 million for 2009. This represents an increase of $23 million or 77% as compared to the year ended December 31, 2009. This increase is due primarily to an increase related to commodity prices partially offset by a decrease related to production volumes.

***Supplemental Non-GAAP Measure.*** We use the non-GAAP measures “Reported EBITDA” and “Adjusted EBITDAX”, among others as further described in *Use of Non-GAAP Financial Information.* We believe these supplemental measures provide meaningful information to our investors; however, due to the limitations of these measures as analytical tools, we rely primarily on our GAAP results. We define Reported EBITDA as net income plus interest and debt expense, income taxes and depreciation, depletion and amortization. Adjusted EBITDAX is defined as Reported EBITDA 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), ceiling test charges or other impairments, adjustments to reflect cash distributions of the earnings from our unconsolidated affiliates, non-cash equity based compensation expenses, transition and restructuring costs we expect not to recur, advisory fees paid to our sponsors and exploration expenses. We believe that the presentation of Reported EBITDA and 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) (v) and supplemental information to investors about certain material non-cash and/or other items that may not continue at the same level in the future. Reported EBITDA and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under U.S. GAAP or as an alternative to net income, 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 Reported EBITDA and Adjusted EBITDAX to our consolidated net income (loss) for the six months ended June 30 and the three years ended December 31:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **Six Months ended June 30,** | | **Years ended December 31,** | | |
|  | **2012** | **2011** | **2011** | **2010** | **2009** |
|  | **(in millions)** | | | | |
| Net income (loss) | $28 | $152 | $262 | $443 | $(911) |
| Interest expense, net of capitalized interest(1) | 67 | 6 | 12 | 21 | 25 |
| Income tax expense (benefit) | 136 | 61 | 220 | 263 | (462) |
| Depreciation, depletion and amortization | 353 | 280 | 612 | 477 | 440 |
| Reported EBITDA | 584 | 499 | 1,106 | 1,204 | (908) |
| Net impact of financial derivatives | (214) | 117 | 47 | (92) | 323 |
| Impairments and ceiling test charges | 63 | — | 158 | 25 | 2,148 |
| Transition and restructuring costs | 183 | 6 | 6 | — | 7 |
| Dividends from unconsolidated affiliates | 8 | 26 | 46 | 50 | 45 |
| Income from unconsolidated affiliates | 6 | 1 | 7 | 7 | 30 |
| Non-cash equity‑based compensation expense | 16 | 11 | 21 | 18 | 19 |
| Financial derivatives premiums | — | — | — | (7) | (173) |
| Advisory fee | 3 | — | — | — | — |
| Exploration expense | 6 | — | — | — | — |
| Adjusted EBITDAX(2) | $655 | $660 | $1,391 | $1,205 | $1,491 |

(1) Includes less than $1 million and $4 million of affiliated interest for the six months ended June 30, 2012 and 2011, and $3 million, $5 million and $4 million of affiliated interest for the years ended December 31, 2011, 2010 and 2009, respectively.

(2) Includes net EBITDAX contribution related to business divestitures of $31 million and $53 million for the six months ended June 30, 2012 and 2011, and $136 million, $203 million and $206 million for the years ended December 31, 2011, 2010 and 2009, respectively.

**Liquidity and Capital Resources**

***Overview***

Our primary sources of liquidity are cash generated by operations and borrowings under the RBL Facility. Our primary uses of cash are working capital requirements, debt service requirements and capital expenditures. Based on our current level of operations and available cash, we believe our cash flows from operations, combined with availability under the RBL Facility provides us sufficient liquidity to fund our current obligations, projected working capital requirements, debt service requirements and capital spending requirements over the next twelve months and the foreseeable future. We cannot assure you, however, that our business will generate sufficient cash flows from operations or that future borrowings will be available to us under the RBL Facility in an amount sufficient to enable us to pay our indebtedness, including the notes, or to fund our other liquidity needs. Our ability to do so depends on prevailing economic conditions, many of which are beyond our control. In addition, upon the occurrence of certain events, such as a change of control, we could be required to repay or refinance our indebtedness. We cannot assure you that we will be able to refinance any of our indebtedness, including the RBL Facility, the senior secured term loan, the senior secured notes and the senior notes, on commercially reasonable terms or at all. Any future acquisitions, joint ventures or other similar transactions will likely require additional capital, and there can be no assurance that any such capital will be available to us on acceptable terms or at all.

We are highly leveraged and our liquidity requirements will be significant, primarily due to debt service requirements. As of June 30, 2012, our long-term debt is approximately $4.25 billion, with approximately $1.25 billion of additional borrowing capacity available under the RBL Facility. As of June 30, 2012, our debt was comprised of $2.75 billion in senior notes due in 2019 and 2020, a $750 million senior secured term loan with a six-year maturity, and $750 million outstanding under the RBL Facility with a five-year maturity. In August 2012, we issued an additional $350 million of the initial 2022 senior notes and used a substantial portion of the proceeds to reduce amounts outstanding under the RBL facility. Additionally, we repriced our $750 million senior secured term loan reducing the interest rate from 6.5% to 5.0%. Our net cash interest expense for the year ended December 31, 2011 and the twelve month period ended June 30, 2012 was $12 million and $73 million. However, on a pro forma basis including the effects of our financing transactions in conjunction with the Acquisition and subsequent issuances and repayments as discussed as well as repricing our senior secured term loan, our net cash interest expense for the year ended December 31, 2011 would have been approximately $313 million. Assuming the RBL Facility is fully drawn, each one eighth point change in assumed blended interest rates would result in a $3.4 million change in annual interest expense on indebtedness under the RBL Facility and our senior secured term loan.

*The RBL Facility*

In connection with the Acquisition Transactions, we entered into the RBL Facility, which provides for up to $2.0 billion of borrowings, of which we drew $750 million upon closing the Acquisition Transactions. The RBL Facility is available to fund working capital and for general corporate purposes. In August 2012, we repaid approximately $350 million of outstanding borrowings under the RBL Facility using the proceeds from the additional $350 million initial 2022 senior notes offering discussed above. With the notes issuance our borrowing base was reduced to approximately $1.9 billion. For a description of the RBL Facility, see “Description of Other Indebtedness—The RBL Facility.”

The RBL Facility contains customary representations and warranties and customary affirmative and negative covenants, including, among other things, restrictions on indebtedness, investments, asset sales, mergers and consolidations, prepayments of subordinated indebtedness, liens, transactions with affiliates, and dividends and other distributions. The RBL Facility also includes customary events of defaults including a change of control.

*Senior Secured Term Loan*

We have a $750 million senior secured term loan facility that contains customary representations and warranties and customary affirmative and negative covenants, including, among other things, restrictions on indebtedness, investments, asset sales, mergers and consolidations, prepayments of subordinated indebtedness, liens, transactions with affiliates, and dividends and other distributions, which are substantially similar to the covenants in the indenture governing the senior secured notes. In August 2012, we repriced our senior secured term loan reducing the interest rate from 6.5% to 5%. Our senior secured term loan also includes customary events of defaults.

*The Senior Notes and the Senior Secured Notes*

The indentures governing the notes contain covenants that, among other things, limit our ability, and the ability of our restricted subsidiaries, to:

• incur additional indebtedness and guarantee indebtedness;

• pay dividends or make other distributions in respect of, or repurchase or redeem, capital stock;

• prepay, redeem or repurchase certain debt;

• make loans and investments;

• sell or otherwise dispose of assets;

• incur liens;

• enter into transactions with affiliates;

• enter into agreements restricting our subsidiaries’ ability to pay dividends; and

• consolidate, merge or sell all or substantially all of our assets.

These limitations are subject to a number of qualifications and exceptions that set forth in the indentures.

*Overview of Cash Flow Activities.* During the period from March 23 (inception) to June 30, 2012, we used operating cash flow of approximately $92 million. During the period from January 1 to May 24, 2012, we generated operating cash flow of approximately $580 million. We utilized these amounts to fund our capital programs, repay amounts outstanding under our various credit facilities and other debt obligations. For the six months ended June 30, and the three years ended December 31, our cash flows from operations are summarized as follows:

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Successor** | **Predecessor** | | | | |
|  | **March 23 (inception) to June 30,** | **January 1 to May 24,** | **June 30,** | **December 31,** | | |
|  | **2012** | **2012** | **2011** | **2011** | **2010** | **2009** |
|  |  |  |  |  |  |  |
| **Cash Flow from Operations** |  | **(in millions)** | | | | |
| *Operating activities* |  |  |  |  |  |  |
| Net (loss) income | $(150) | $178 | $152 | $262 | $443 | $(911) |
| Impairments/Ceiling test charges | 1 | 62 | — | 152 | 25 | 2,123 |
| Other income adjustments | 48 | 537 | 368 | 979 | 859 | (4) |
| Change in other assets and liabilities | 9 | (197) | 143 | 33 | (260) | 365 |
| Total cash flow from operations | $(92) | $580 | $663 | $1,426 | $1,067 | $1,573 |
| **Other Cash Inflows** |  |  |  |  |  |  |
| *Investing activities* |  |  |  |  |  |  |
| Net proceeds from the sale of assets | 22 | 9 | 24 | 612 | 155 | 93 |
| Other | — | — | — | — | 4 | — |
|  | 22 | 9 | 24 | 612 | 159 | 93 |
| *Financing activities* |  |  |  |  |  |  |
| Proceeds from long term debt | 4,323 | 215 | 925 | 2,030 | 500 | 100 |
| Contributions | 3,300 | 960 | — | — | — | — |
| Net change in note payable with parent company and affiliates | — | — | — | — | 489 | — |
|  | 7,623 | 1,175 | 925 | 2,030 | 989 | 100 |
| Total cash inflows | $7,645 | $1,184 | $949 | $2,642 | $1,148 | $193 |
| **Cash Outflows** |  |  |  |  |  |  |
| *Investing activities* |  |  |  |  |  |  |
| Capital expenditures | $150 | $636 | $675 | $1,591 | $1,238 | $1,115 |
| Cash paid for acquisitions | 7,126 | 1 | 1 | 22 | 51 | 131 |
| Increase in note receivable with affiliate | — | — | — | 236 | — | — |
| Other | — | — | — | — | — | 3 |
|  | $7,276 | $637 | 676 | 1,849 | 1,289 | 1,249 |
| *Financing activities* |  |  |  |  |  |  |
| Repayment of long term debt | 80 | 1,065 | 825 | 1,480 | 1,034 | 180 |
| Net change in note payable with parent company and affiliates | — | — | 145 | 781 | — | 256 |
| Debt issuance costs | 142 | — | — | — | — | — |
| Other | — | — | 6 | 7 | 1 | — |
|  | 222 | 1,065 | 976 | 2,268 | 1,035 | 436 |
| Total cash outflows | $7,498 | $1,702 | $1,652 | $4,117 | $2,324 | $1,685 |
| Net change in cash and cash equivalents | $55 | $62 | $(40) | $(49) | $(109) | $81 |

**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, 2012, for each of the periods presented:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **2012** | **2013 - 2014** | **2015 - 2016** | **Thereafter** | **Total** |
|  | **(in millions)** | | | | |
| Long-term financing obligations: |  |  |  |  |  |
| Principal | $— | $— | $— | $4,250 | $4,250 |
| Interest | 155 | 618 | 618 | 818 | 2,209 |
| Liabilities from price risk management activities | — | 11 | 6 | — | 17 |
| Operating leases | 5 | 20 | 20 | 4 | 49 |
| Other contractual commitments and purchase obligations: |  |  |  |  |  |
| Volume and transportation commitments | 43 | 178 | 191 | 369 | 781 |
| Other obligations | 122 | 139 | 50 | 188 | 499 |
| Total contractual obligations | $325 | $966 | $885 | $5,629 | $7,805 |

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

***Liabilities from Price Risk Management Activities.*** These amounts include the fair value of our price risk management liabilities. We have also excluded all margin and other deposits held associated with these contracts from these amounts.

***Operating Leases.*** For a further discussion of these obligations, see Note 8 of our “Notes to Consolidated Financial Statements.” In conjunction with the Transactions we entered into a new five year operating lease for office space.

***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 and construction contracts. 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. Upon the closing of the Acquisition Transactions, affiliates of the Sponsors and other investors entered into a Management Fee Agreement with Parent and EP Energy Global LLC requiring an annual advisory fee of $25 million to be paid. The agreement 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 IPO transaction.

**Off-Balance Sheet Arrangements**

We enter into a variety of financing arrangements and contractual obligations, some of which are referred to as off-balance sheet arrangements. These include guarantees and letters of credit.

***Guarantees***

We periodically provide indemnification arrangements related to assets or businesses we have sold. These indemnification arrangements include, but are not limited to, indemnification for income taxes, the resolution of existing disputes, environmental matters, and necessary expenditures to ensure the safety and integrity of assets sold. As of June 30, 2012, we had no obligations related to our guarantee and indemnification arrangements.

***Letters of Credit***

We enter into letters of credit in the ordinary course of our operations as well as periodically in conjunction with sales of assets or businesses. As of June 30, 2012, we had outstanding letters of credit of approximately $8 million. For additional information on our counterparty credit and nonperformance risk, see Note 5 of our “Notes to Consolidated Financial Statements.”

**Critical Accounting Estimates**

Our significant accounting policies are described in Note 1 of each of our consolidated financial statements 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 judgments, complex or subjective judgment necessary to account for inherently uncertain matters and those 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. We have discussed the development and selection of the following critical accounting estimates and related disclosures with our Audit Committee.

***Accounting for Oil and Natural Gas Producing Activities.*** Prior to its acquisition on May 24, 2012, our predecessor accounted for oil and natural gas producing activities in accordance with the full cost method. Subsequent to the acquisition, we follow the successful efforts method of accounting for our oil and natural gas properties.

Our estimates of proved reserves reflect quantities of oil, natural gas and NGL 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 of 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 our Board 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 our Board of Managers, conducts an audit of the estimates of a significant portion of our proved reserves. Ryder Scott conducted an audit of our predecessor’s estimates of proved reserves as of December 31, 2011.

As of December 31, 2011, 50% of our predecessor’s total consolidated proved reserves were undeveloped (49% including Four Star) and 9% 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 judgments based on available data for various fields increase the likelihood of significant changes in these estimates.

***Full Cost.*** Under the full cost accounting method followed by our predecessor prior to the acquisition, substantially all of the costs incurred in connection with the acquisition, exploration and development of oil and natural gas reserves, including salaries, benefits and other internal costs directly related to these activities, asset retirement costs and interest on significant capital projects were capitalized. Capitalized costs were aggregated in full cost pools by country, regardless of whether reserves were actually discovered. Depletion expense of these capitalized amounts plus estimated future development costs over the life of the proved reserves was based on the unit of production method. If all other factors were held constant, a 10% increase in proved reserves would decrease the unit of production depletion rate by 9% and a 10% decrease in proved reserves would increase the unit of depletion rate by 11%..

Additionally, under the full cost method our predecessor conducted quarterly ceiling tests of capitalized costs for each of its full cost pools. Total capitalized costs, 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%, plus the cost of unproved oil and natural gas properties not being amortized less related income tax effects. In calculating the ceiling test and estimating proved reserves, a first day 12-month average price was used. If the discounted future net cash flows were not greater than or equal to the total capitalized costs, capitalized costs were written-down to the level of discounted future net cash flows. 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.

Finally, under the full cost method, oil and natural gas properties included unproved property costs that were excluded from costs being depleted. These unproved property costs included non-producing leasehold, geological and geophysical costs associated with unevaluated leasehold or drilling interests and exploration drilling costs in investments in unproved properties and directly owned major development projects. Costs were excluded on a country‑by‑country basis until proved reserves were found or until it was determined that the costs were impaired. All costs excluded were reviewed at least quarterly to determine if exclusion from the full-cost pool continued to be appropriate. If costs were determined to be impaired, the amount of any impairment was transferred to the full cost pool if a reserve base exists or is expensed if a reserve base had not yet been created. Impairments transferred to the full cost pool increased the depletion rate for that country.

***Successful Efforts.*** Under the successful efforts method (which was used subsequent to the Acquisition), 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. Depreciation, depletion, amortization and impairment of oil and natural gas properties are calculated on a depletable unit basis. Additionally, gain or loss is generally recognized on all sales of oil and natural gas properties. We capitalize salaries and benefits that we determine are directly attributable to our oil and natural gas activities.

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, 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 based on our current drilling plans. 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. Subsequent to the Acquisition (May 25, 2012) to June 30, 3012, we did not record any impairments.

***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, 2012, our net asset retirement liability is approximately $235 million, including approximately $64 million related to the Gulf of Mexico oil and gas properties sold in July 2012.

***Price Risk Management Activities.*** We record the derivative instruments used in our price risk management activities at their fair values. We estimate the fair value of our derivative instruments using exchange prices, third‑party pricing data and valuation techniques that incorporate specific contractual terms, statistical and simulation analysis and present value concepts. One of the primary assumptions used to estimate the fair value of 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 price risk management activities to changes in fair values arising from immediate selected potential changes in oil and natural gas prices at June 30, 2012:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  |  | **Change in Price** | | | |
|  |  | **10 Percent Increase** | | **10 Percent Decrease** | |
|  | **Fair Value** | **Fair Value** | **Change** | **Fair Value** | **Change** |
|  | **(in millions)** | | | | |
| Production‑related derivatives—net assets (liabilities) | $460 | $102 | $(358) | $814 | $354 |

Other significant assumptions that we use in determining the fair value of our derivative instruments are those related to the credit and non-performance risk of our counterparties. We adjust the fair value of our derivative assets for the risk of non-performance of our counterparties considering the collateral posted for the derivative and changes in the counterparties’ creditworthiness, which is in part based on changes in their bond yields, changes in actively traded credit default swap prices (if available) and other information about their credit standing. We adjust the fair value of our derivative liabilities for our creditworthiness utilizing similar inputs considering cash collateral we have posted with our counterparties.

***Income taxes.*** EP Energy LLC is not subject to domestic income taxes and foreign tax amounts are not material to our financial results. However, prior to the settlement of domestic income tax balances (including deferred taxes) of our predecessor with El Paso in conjunction with the acquisition on May 24, 2012, our predecessor recorded 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. The most significant judgments on tax related matters included matters such as valuation allowances, uncertain tax positions, and undistributed earnings of certain unconsolidated affiliates. For a further discussion of these items and other income tax matters, see of our consolidated financial statements included elsewhere in this prospectus.

**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 and natural gas prices impact the amounts at which we sell our oil and natural gas and affect the fair value of our oil and natural gas derivative contracts held; and

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

***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 contractual commitments 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;

• futures contracts, which are exchange‑traded standardized commitments to purchase or sell a commodity or financial instrument, or to make a cash settlement at a specific price and future date;

• options, which convey the right to buy or sell a commodity, financial instrument or index at a predetermined price;

• swaps, 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 of our “Notes to Consolidated Financial Statements.”

***Commodity Price Risk***

*Oil and Natural Gas Derivatives*

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

*Sensitivity Analysis*

The table below presents the 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, 2012:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  |  | **Oil and Natural Gas Derivatives** | | | |
|  |  | **10 Percent Increase** | | **10 Percent Decrease** | |
|  | **Fair Value** | **Fair Value** | **Change** | **Fair Value** | **Change** |
|  | **(in millions)** | | | | |
| Price impact(1) | $460 | $102 | $(358) | $814 | $354 |

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  |  | **Oil and Natural Gas Derivatives** | | | |
|  |  | **1 Percent Increase** | | **1 Percent Decrease** | |
|  | **Fair Value** | **Fair Value** | **Change** | **Fair Value** | **Change** |
|  | **(in millions)** | | | | |
| Discount Rate(2) | $460 | $454 | $(6) | $463 | $3 |
| Credit rate(3) | $460 | $456 | $(5) | $465 | $4 |

(1) Presents the hypothetical sensitivity of our commodity‑based price risk management activities to changes in fair values arising from changes in oil and natural gas prices.

(2) Presents the hypothetical sensitivity of our commodity‑based price risk management activities 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 price risk management activities to changes in credit risk.

***Interest Rate Risk***

We had $4.25 billion of total debt outstanding at June 30, 2012, of which $1.5 billion under the RBL Facility and our new senior secured term loan was variable rate debt.

Assuming a hypothetical increase in our variable interest rate under our existing debt agreements of 100 basis points, our net income for the six months ended June 30, 2012 would have decreased by $2.0 million. For the year ended December 31, 2011, our net income would have decreased by $3.0 million.

During July 2012, we entered into interest rate swaps on $600 million related to our RBL Facility. These interest rate derivatives start in November 2012 extending through April 2017 and attempt to reduce our variable interest rate exposure.

**BUSINESS**

**Our Company**

We are one of North America’s leading independent oil and natural gas producers. We have a large and diverse base of producing assets that provides cash flow to fund the development of our key programs, which at this time are primarily oil-focused. Over the last several years, we have high-graded our future drilling inventory by establishing large acreage positions with repeatable drilling opportunities and more favorable return characteristics. Domestically, we currently operate through three divisions: Central, Eagle Ford and Southern, and have a strategic presence in well-known oil resource areas, including the Eagle Ford Shale, the Altamont Field, the Wolfcamp Shale and South Louisiana Wilcox. Our large and diverse production gas assets include our Haynesville Shale position, substantially all of which is held by production, which gives us a significant presence in unconventional natural gas. We also have a small international presence in Brazil.

Our management team, which has been with us since at least 2007, has an average of 22 years of experience in the oil and gas industry and technical and operating expertise across our geographic regions. Our management team has a track record of identifying, acquiring and developing low-risk, repeatable resource opportunities and has executed a multi-year effort to add assets that fit our competencies. Today, our substantial key program drilling inventory encompasses approximately 4,500 locations and more than 20 years of drilling activity at our current pace. We have operational control over approximately 77% of our producing wells and 88% of our key program drilling inventory as of December 31, 2011. This control has allowed us to continually improve our capital and operating efficiencies. In 2011, we drilled 233 gross wells domestically (182 net) with a success rate of 100%, adding approximately 1,100 Bcfe of proved reserves at a replacement cost of $1.43 per Mcfe, the majority of which was oil.

As of December 31, 2011, we had proved reserves of approximately 4.0 Tcfe with a pre‑tax PV-10 of approximately $7 billion (of which approximately 54% of the PV‑10 was attributed to proved developed producing reserves). We had 182 MMBbls of proved oil reserves, 19 MMBbls of proved NGL reserves and 2,782 Bcfe of proved natural gas reserves, representing 27%, 3% and 70%, respectively, of our total proved reserves. Given the recent commodity price environment, we have shifted our focus primarily to developing our key oil programs, resulting in 48% of our revenues (excluding realized and unrealized gains on financial derivatives) being contributed by oil and NGLs in the fourth quarter of 2011, versus 34% in the fourth quarter of 2010. Our oil production for the month of December 2011 was approximately 24,000 Bbls/d, which contributed to our approximate 50% year-over-year growth in oil production for the fourth quarter of 2011. We anticipate that approximately 91% of our capital expenditures for 2012 will be allocated to oil-focused key programs. For the six month period ended June 30, 2012, 57% of our revenues (excluding realized and unrealized gains on financial derivatives) were contributed by oil and NGLs, versus 35% during the same period in 2011. For the month of June 2012, our oil production was approximately 27,000 Bbls/d.

For the six months ended June 30, 2012, on a pro forma basis after giving effect to the Acquisition Transactions and the Refinancing Transactions, we generated Adjusted EBITDAX of $655 million on average daily production of 906 MMcfe/d. See “Summary—Summary Historical and Pro Forma Consolidated Financial and Other Operating Data” for our definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to amounts reported under GAAP.

The following table provides summary data for each of our areas of operation:

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | **As of December 31, 2011** | | | | **As of June 30, 2012** |
|  | **Proved Reserves (Bcfe)** | **% Proved Developed** | **PV-10** | **Net Acres** | **Average Daily Production (MMcfe/d)** |
|  | **(dollars in millions)** | | | | |
| **United States** |  |  |  |  |  |
| Central |  |  |  |  |  |
| Haynesville Shale | 903 | 34% | $719 | 41,000 | 317 |
| South Louisiana Wilcox | 31 | 48 | 143 | 183,000 | 16 |
| Altamont Field | 551 | 37 | 1,479 | 176,000 | 62 |
| Other Central | 1,117 | 75 | 998 | 1,339,000 | 208 |
| Eagle Ford |  |  |  |  |  |
| Eagle Ford Shale | 642 | 18 | 2,283 | 157,000 | 91 |
| Southern |  |  |  |  |  |
| Wolfcamp Shale | 148 | 12 | 337 | 138,000 | 10 |
| Other Southern(1) | 326 | 94 | 536 | 314,000 | 110 |
| Total United States | 3,718 | 48 | 6,495 | 2,348,000 | 814 |
| **International** |  |  |  |  |  |
| Brazil | 95 | 100 | 210 | 132,000 | 36 |
| Egypt(2) | — | — | — | 774,000 | — |
| Total Consolidated | 3,813 | 50 | 6,705 | 3,254,000 | 850 |
| **Unconsolidated Affiliate(3)** | 174 | 86 | 311 |  | 56 |
| Total Combined | 3,987 | 51 | $7,016 |  | 906 |

(1) Gulf of Mexico assets were sold in July 2012 and comprised reserves of 90 Bcfe, PV-10 of $150 million, net acres of 233,000 and average daily production of 45 Mcfe/d.

(2) Sold June 2012.

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

***Key Programs***

Over the past five years, our strategy has been to focus on areas that offer repeatable drilling programs, enabling us to reduce development costs, and to grow our asset base and inventory size. We have consistently improved the quality and increased the number of our drilling opportunities. During 2011, our principal focus was in the Haynesville Shale, the Eagle Ford Shale, the Wolfcamp Shale, the Altamont Field and South Louisiana Wilcox. We are redeploying the capital allocated to the Haynesville Shale to our oil programs. The technical and operating experience gained from our successful Haynesville program has been employed in our other key programs, including the Eagle Ford Shale.

*Haynesville Shale*

The initial execution of our strategy was in the Haynesville Shale, where we had existing conventional production as a result of historical development activities in east Texas and north Louisiana. Our operations in the Haynesville Shale are primarily focused in DeSoto Parish and Caddo Parish, Louisiana. We acquired additional leasehold interests through the acquisition of Peoples Energy Production Company in 2007. We piloted horizontally drilled wells in the Haynesville Shale, experimenting with different horizontal lateral lengths and fracture stimulation staging, with the objective of delivering optimal capital efficiency, finding costs and returns. High production rates in our Haynesville program combined with very low operating and development costs create competitive returns for us even at low natural gas prices. In addition, our acreage in the Haynesville Shale is predominately held by production, giving us the flexibility to pace our development and optimize our returns. Furthermore, our operations are surrounded by existing infrastructure, providing strong take-away access to markets. As of June 30, 2012, we had 66 net operated wells in this area. During the first quarter of 2012, although we had a very efficient drilling program in the Haynesville Shale, we suspended the program and released all rigs due to low natural gas prices.

*Eagle Ford Shale*

Beginning in late 2008, we were an early entrant in the Eagle Ford Shale, acquiring our interests through leasehold acquisitions for less than $1,000 per acre on average. Our operations in the Eagle Ford Shale are focused in LaSalle, Dimmit, Atascosa and Webb counties of south Texas. Overall, we hold rights to approximately 157,000 net acres across all Eagle Ford areas, where approximately 77,000 net acres are under development in our central Eagle Ford area. During 2010 and 2011, we improved the efficiency and productivity of our development program, reducing per-well capital costs by approximately 16% and drilling cycle time by more than 35% year over year. Most of our wells have had initial production rates that range from 600 to over 1,000 Boe/d, and our oil production in this area has grown significantly since the beginning of 2011. The Eagle Ford Shale currently provides the highest economic returns in our portfolio. Significant strengths of the Eagle Ford Shale also currently include a multi-year future drilling location inventory, favorable crude oil pricing relative to the WTI index and a newly constructed midstream infrastructure with ample take-away capacity. As a result, the Eagle Ford Shale has become one of our key programs and a contributor to the increase in our oil reserves and production. As of December 31, 2011, we had 1,246 future drilling locations in the Eagle Ford Shale. As of June 30, 2012, we had 98 net operated wells and are currently running four rigs in the Eagle Ford Shale. We plan to add a fifth rig and drill 79 gross wells in 2012 based on our capital budget.

*Wolfcamp Shale*

In 2009 and 2010, we established a new major oil shale position by successfully leasing approximately 138,000 net acres in the Wolfcamp Shale in the Permian Basin in west Texas. Our operations in the Wolfcamp Shale are focused in Reagan, Crockett, Upton and Irion counties. We were an early entrant in the Wolfcamp Shale, acquiring our interests through leasehold acquisitions for less than $1,500 per acre on average. We have leveraged our technical and operating expertise, and in 2011 advanced our understanding of this area using the same approach and techniques that have allowed us to be successful in the Haynesville and Eagle Ford Shales. As a result, in late 2011, we completed a 7,500 foot lateral well with 25 stages that tested at an initial production rate of 1,369 Boe/d, our highest initial production rate to date. In addition, the Wolfcamp Shale has high oil in place, a multi-year future drilling location inventory and favorable lease owner dynamics with the Texas University Land system as the predominant landowner. As of December 31, 2011, we had 983 future drilling locations in the Wolfcamp Shale. As of June 30, 2012, we had 26 net operated wells and are currently running one rig in the Wolfcamp Shale. We plan to drill 15 gross wells in 2012 based on our capital budget.

*Altamont Field*

In 2007, we commenced a reengineering effort in the Altamont Field in Utah, a legacy oil asset. Our operations in the Altamont Field are focused in the Uinta Basin. Altamont was initially developed in the 1970s, and we are applying current drilling and stimulation technology to vertically drill and develop this prolific oil area. We have enhanced the value of this field through infill drilling, for which we received regulatory approval in 2008. The Altamont Field has a multi-year inventory of future drilling locations, giving us a substantial opportunity for growth in oil production. Since our acreage is predominantly held by production, we have greater flexibility to improve both our costs and technical understanding of this area, while also growing returns. As of December 31, 2011, we had 1,336 future drilling locations in the Altamont Field. As of June 30, 2012, we had 307 net operated wells and are currently running two rigs in the Altamont Field. We plan to drill 21 gross wells in 2012 based on our capital budget.

*South Louisiana Wilcox*

In south Louisiana, we are developing our emerging South Louisiana Wilcox play. This is a relatively new oil-focused play that we have added to our drilling program. Our activity is located primarily in Beauregard Parish and is focused on the Wilcox Sands. We have over 1,000 square miles of 3-D seismic data in South Louisiana Wilcox, providing valuable information in selecting drilling locations. South Louisiana Wilcox is a conventional vertical well play that produces both oil and natural gas from a series of completed sands. A significant strength of South Louisiana Wilcox is its access to Louisiana Light Sweet Crude and Gulf Coast NGL pricing, which trade at a premium relative to the WTI index. In addition, the resource does not compete for horizontal drilling and completion services due to vertical drilling and completion design. As of December 31, 2011, we had 260 future drilling locations in South Louisiana Wilcox. As of June 30, 2012, we had 19 net operated wells and are currently running one rig in South Louisiana Wilcox. We plan to drill 15 gross wells in 2012 based on our capital budget.

***Other Gas Assets***

We have a large and diverse base of other domestic producing assets that provides cash flow to fund the development of our key programs. We do not anticipate a material portion of our 2012 capital expenditure budget to be spent on these assets.

*Arklatex/Unconventional*

Our Arklatex land positions comprise 104,470 total net acres focused on tight gas sands production. We have approximately 449,000 net acres in our unconventional plays. Our production is from vertical CBM wells development in Alabama, vertical and horizontal CBM wells in the Hartshorne coals in Oklahoma and the New Albany Shale in Indiana (sold in July 2012). We have high average working interests and long life reserves in these areas. For the six months ended June 30, 2012 we had average daily production of 119 MMcfe/d.

*Texas Gulf Coast/Gulf of Mexico*

We have significant assets in fields throughout the Texas Gulf Coast. In addition, prior to selling our Gulf of Mexico assets in July 2012, this area included interests in 69 Blocks offshore of the Louisiana, Texas and Alabama coastlines focused on deep targets (greater than 12,000 feet) in relatively shallow water depths (less than 400 feet). In these areas, we licensed over 8,700 square miles of 3D seismic data onshore and over 61,000 square miles of 3D seismic data offshore. As of December 31, 2011, these operations included 314,000 total net acres, and for the six months ended June 30, 2012 we had average daily production of 111 MMcfe/d.

*Raton Basin*

Our operations in the Raton Basin of northern New Mexico and southern Colorado, where we own the minerals beneath the Vermejo Park Ranch, are primarily focused on coal bed methane production. As of December 31, 2011, these operations included 606,000 total net acres, and for the six months ended June 30, 2012 we had average daily production of 81 MMcfe/d.

*Rocky Mountains*

We have a non-operated working interest in the County Line coal bed methane property in Wyoming, with additional non-producing acreage in Colorado, Wyoming, North Dakota and Utah. As of December 31, 2011, these operations included 179,000 total net acres, and for the six months ended June 30, 2012 we had average daily production of 9 MMcfe/d.

*Four Star*

We have an approximate 49% equity interest in Four Star. Production is from high quality conventional and coal bed methane assets in the San Juan, Permian, Hugoton and South Alabama basins and the Gulf of Mexico. For the first six months of 2012, our equity interest in Four Star’s daily equivalent natural gas production averaged approximately 56 MMcfe/d.

***2012 Capital Expenditures***

We have approved a capital expenditure budget between $1.5 billion and $1.6 billion for 2012, of which about $1.2 billion will be spent on drilling and completion activities. Our total oil and natural gas capital expenditures were $762 million for the six months ended June 30, 2012, of which $758 million were domestic capital expenditures. Our spending will be heavily weighted toward oil-focused reservoirs, which are forecasted to comprise 91% of our capital expenditures; our key programs will comprise 97% of our spending. A substantial portion of our capital expenditure budget is expected to be funded from operating cash flows, which should enable us to grow reserves and production while maintaining sufficient liquidity. We expect to periodically review our capital spending plans versus commodity prices and well performance and adjust spending as necessary. For example, the portion of our budget dedicated to gas-weighted resources has declined significantly in 2012, due primarily to reductions in Haynesville Shale activity as a result of low current natural gas prices.

|  |  |  |
| --- | --- | --- |
| **2012 Capex Budget** $1.5 Billion‑$1.6 Billion(1) | **Key Drilling Locations(2)** 4,498 Locations | **2012 Gross Wells Expected to Complete in Key Programs** 144 Gross Well |
|  |  |  |

(1) Includes approximately $100 million of capitalized interest, information technology and capitalized direct labor costs.

(2) As of December 31, 2011 (includes PUD locations shown on a risked basis).

**Competitive Strengths**

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

***Large and Diverse Producing Asset Base***

Our vast resource base consists of approximately 4.0 Tcfe of proved reserves as of December 31, 2011 and are located on 3.3 million net acres. Approximately 1.7 Tcfe, or 42%, of our proved reserves are proved developed producing assets, and we generated an average of 838 MMcfe/d in 2011 from approximately 6,000 wells. During the first half of 2012, we generated an average of 906 MMcfe/d. Our existing assets are geographically diversified among many of the major basins of North America, insulating us to some extent from regional commodity pricing and costs dislocations that occur from time to time. Our producing assets provide a diverse source of cash flow to fund the development of our key programs, significantly reducing our reliance on outside sources of capital and improving our ability to replace and grow production in the future. While our existing producing assets are well diversified, we maintain a focused and concentrated approach that enables us to drive efficiencies, benefit from economies of scale, remain flexible in allocating capital to our most profitable projects and leverage our knowledge base from one project to the next.

***Extensive Inventory of Low-Risk Drilling Opportunities***

We have established a substantial resource base in unconventional oil plays to supplement our already significant inventory of unconventional natural gas resources. With the addition of the Eagle Ford and Wolfcamp shales, the ongoing development of our Altamont Field and the recent addition of South Louisiana Wilcox, we estimate have more than 20 years of drilling inventory in approximately 4,500 drilling locations across our key programs, 85% of which are located in oil-focused reservoirs. The move to oil-focused reservoirs has allowed us to take advantage of higher oil prices and has improved cash flow through commodity diversity. The development of these assets will generate accelerated growth in oil production and reserves and provide us the flexibility to take advantage of strength in either gas or oil commodity price environments. We expect that the oil composition of our production will continue to increase as we develop our key oil programs over the next several years.

***Strong Financial Profile***

Our large and diverse portfolio produced 906 MMcfe/d in the six months ended June 30, 2012, which generated Adjusted EBITDAX of $655 million for the six months ended June 30, 2012. Pro forma for the Refinancing Transactions, as of June 30, 2012, we would have had approximately $1.6 billion of liquidity. Additionally, we maintain a robust hedging program that protects cash flows to fund development plans through the commodity cycle. As of August 20, 2012, our hedged volumes for 2012, 2013, 2014 and 2015 represent 85%, 79%, 38% and 16%, respectively, based on our total 2011 equivalent production.

***Low Cost and Efficient Operations***

We maintain a significant degree of operational control over our portfolio, operating approximately 77% of our producing wells and 88% of our key program drilling inventory as of December 31, 2011. Our operational efficiency has resulted in leading well cost performance in our key programs. Our three-year average reserve replacement cost of $1.55 per Mcfe ranks among the lowest in our peer group. Based on our operating efficiency, we believe our ability to generate significant cash flow in a variety of commodity price environments is enhanced, especially as our production profile becomes increasingly oil‑focused. We have reduced our domestic unit operating costs over the last several years by approximately $0.21 per Mcfe by lowering lifting costs, reducing subsurface, compression and disposal costs and divesting of high cost production areas. From 2007 to 2011, we reduced our unit lifting costs by approximately 28%. A lower cost structure should allow us to preserve returns and margins throughout the commodity cycle. Given our proven ability to find and develop reserves economically, we believe we should be able to convert our sizeable drilling portfolio at similar or better rates of return going forward.

***High Caliber Management Team with Proven Track Record***

Our senior management team, with an average of 22 years of experience, has a strong track record both at El Paso Corporation and in former leadership roles with Burlington Resources, ConocoPhillips and other leading producers. In addition, our operational team has significant experience in horizontal drilling and developing shales. We have an organizational structure that allows for greater ownership and accountability at the asset level through multi‑disciplined asset teams organized around our key geographic areas. Through a combination of invested equity and incentive programs, we believe our management and operational teams are motivated to deliver high returns and increase long-term value. We employ a centralized operational structure to accelerate the knowledge transfer around the execution of our drilling and completion programs and to continually enhance our field operations and base production performance. Our management and operational teams are focused on increasing our drilling opportunities and capital management and are motivated to ensure safe and reliable operations while delivering improved capital and operating efficiency. In addition, our supply chain management group enables us to partner with suppliers in order to improve the cost efficiency of services across the entire operation.

**Business Strategy**

Our strategy is to use our strengths to generate competitive returns from our capital investment programs by growing proved reserves, production volumes, and future drilling opportunities while optimizing our existing asset base. The key elements of this strategy are:

***Grow Our Production and Reserves with a Near-Term Focus on Oil***

Currently, our primary focus is developing our key oil programs. We have a strategic presence in well-known oil resource areas, including the Eagle Ford Shale, the Altamont Field, the Wolfcamp Shale and South Louisiana Wilcox, and 85% of our key future drilling locations are in oil-focused areas. Our overall oil production volumes grew approximately 58% for the first six months of 2012 compared to the first six months of 2011, and our 2012 capital expenditure budget is heavily weighted toward oil-focused reservoirs, which comprise 91% of our capital expenditures.

***Continue to Leverage Technical and Operating Expertise to Develop Repeatable, Low-Risk Plays***

We plan to continue to evaluate new opportunities to gain scale and optimize our operating performance while leveraging our past experience to establish repeatable, low-risk plays in the future. Since our initial entry into the Haynesville Shale in 2007, we have drilled some of the most efficient wells in the area, and our production per well is among the best in the areas in which we operate. We entered the Eagle Ford and Wolfcamp shales through grassroots leasing efforts in late 2008 and applied the expertise gained from horizontal drilling in the Haynesville. We have subsequently leased large acreage positions in the Wolfcamp Shale, developed additional zones within our other key programs and have significantly improved the quality and number of our drilling opportunities.

***Continuously Improve Capital and Operating Efficiency***

We maintain a disciplined approach to spending that directs capital in a manner that seeks to maximize returns. Our large and diverse portfolio provides sufficient scale and diversity to conduct operations in a cost-efficient manner and reallocate capital as appropriate to maintain attractive returns. We have developed particular expertise as an operator of unconventional oil and natural gas plays. In each of our key programs, we have realized substantial reductions in drilling and completion costs and large improvements in cycle times by applying expertise from prior activities. For example, in the Eagle Ford Shale, we have quickly improved our efficiency and productivity, reducing capital costs by 16% and cycle time by more than 35% since the beginning of 2010.

***Maintain Financial Strength and Flexibility***

We intend to fund growth predominantly with internally generated funds while maintaining ample liquidity. As of June 30, 2012, on a pro forma basis after giving effect to the Refinancing Transactions, we would have had approximately $1.6 billion of liquidity. Our hedging program should further protect cash flows to provide sufficient funding levels for our capital program. In addition, consistent with past practices, we intend to continue to high-grade our asset base and remain opportunistic with respect to divesting other gas assets. As we pursue our strategy of developing high-return opportunities in our key programs, we expect our reserves to grow, thereby enhancing our liquidity and financial strength.

***Manage Commodity Price Volatility***

We maintain a robust hedging program designed to mitigate volatility in commodity prices and protect our enterprise cash flows. As of August 20, 2012, we have hedged for the remainder of 2012 a total of 4.6 MMBbls of oil at a weighted average price of $97.11 per Bbl and 103 TBtu of natural gas at a weighted average price of $4.47 per MMBtu. As of August 20, 2012, our hedged volumes for 2012, 2013, 2014 and 2015 represent 85%, 79%, 38% and 16%, respectively, based on our total 2011 equivalent production.

**Operations**

In the U.S., we currently operate through three divisions: Central, Eagle Ford and Southern. During 2011, we focused our activities on our key programs. Over the past few years, we have high-graded our future drilling opportunities through producing property acquisitions, acreage acquisitions and the sale of producing properties that tended to be late in life and without meaningful future drilling opportunities. As a result, our drilling programs are now lower risk, more concentrated, more domestic, more focused on oil and more profitable.

Internationally, our portfolio consists of producing fields along with exploration and development projects in offshore Brazil. Our Brazilian operations are in the Camamu, Espirito Santo and Potiguar basins. Previously we also had exploration activities in Egypt, but our interests were sold in June 2012.

***U.S.***

*Central*

The Central division includes operations that have largely been focused on shale gas primarily the Haynesville Shale in north Louisiana and oil and natural gas production from fractured tight sands within the Altamont Field in Utah. Additionally we have tight gas sands production in north Louisiana and east Texas, coal bed methane production in the Black Warrior Basin of Alabama and in the Arkoma Basin of Oklahoma, New Albany Shale production in Indiana and conventional oil production in our South Louisiana Wilcox program. The Central division operations have generally been characterized by lower development costs, higher drilling success rates and longer reserve lives. We have increased our drilling prospects in this division and have grown production in this area for five consecutive years. For the first six months of 2012, daily production for the Central division averaged 603 MMcfe. During 2011, we invested $790 million on capital projects and production averaged 576 MMcfe/d in the Central division.

*Haynesville Shale.* In 2011, the Haynesville Shale was our key program in the Central division. It is located in northwest Louisiana and east Texas. Our operations are in the Holly, Bethany Longstreet and Logansport fields. A majority of our acreage is located in a high deliverability part of the play.

We have a history of delivering improved capital performance in the Haynesville Shale. In 2011, our average capital costs per well in Haynesville were $8.9 million, with a best of $7.7 million, as compared to average capital costs of $10.8 million for the first three wells in the location. In addition, our 2011 average cycle time per well was 34 days, with a best of 27 days, as compared to an average cycle time of 52 days for the first three wells in the location.

During 2011, we operated an average of four drilling rigs and invested $409 million in capital expenditures in our Haynesville Shale. Average production for the year ended December 31, 2011 was 265 MMcfe/d compared to 143 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in the Haynesville Shale included:

• 41,000 total net acres, including approximately 29,000 undeveloped net acres;

• 903 Bcfe of estimated net proved reserves; and

• 93 net producing wells.

We have allocated approximately $96 million in capital expenditures to our Haynesville Shale program in 2012. Although we had a very efficient drilling program in the Haynesville Shale, we shut down the program due to low natural gas prices. We have released all rigs and will redeploy the capital allocated to the Haynesville Shale to our oil programs.

*Altamont Field.* The Altamont Field is our key program in the Western division. Our focus has been on drilling vertical fractured wells through fractured tight oil sands in the Uinta Basin located in Utah. We have gained operational efficiencies as we have developed the field.

We continue to focus on improving capital performance in the Altamont Field. In 2011, our average cycle time per well was 48 days, with a best of 23 days, as compared to an average cycle time of 66 days for the first three wells in the location. Our average 2011 capital costs per well in Altamont were $6.8 million, with a best of $4.6 million, as compared to average capital costs of $6.6 million for the first three wells in the location.

During 2011, we operated an average of three drilling rigs and invested $173 million in capital expenditures in the Altamont Field. Average production for the year ended December 31, 2011, was 55 MMcfe/d compared to 51 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in the Altamont Field included:

• 176,000 total net acres, including approximately 56,000 undeveloped acres;

• 551 Bcfe of estimated net proved reserves; and

• 301 net producing wells.

We have allocated approximately $181 million in capital expenditures to the Altamont Field in 2012.

*South Louisiana Wilcox.* Our South Louisiana Wilcox play is located primarily in Beauregard Parish, Louisiana and is focused on the Wilcox Sands. This is a conventional vertical well play, utilizing 3-D seismic to help with location selection, that produces both oil and natural gas from a series of completed sands.

During 2011, we operated one drilling rig and invested $148 million in capital expenditures in South Louisiana Wilcox. Average production for the year ended December 31, 2011 was 10 MMcfe/d compared to 9 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in South Louisiana Wilcox included:

• 183,000 total net acres, including approximately 173,000 net undeveloped net acres;

• 31 Bcfe of estimated net proved reserves; and

• 13 net producing wells.

We have allocated approximately $121 million in capital expenditures to South Louisiana Wilcox in 2012.

*Arlatex/Unconventional.* Our Arklatex land positions are primarily focused on tight gas sands production in the Travis Peak/Hosston, Bossier and Cotton Valley formations. Our operations are in the Bear Creek, Vacherie Dome, Holly, Bethany, Longstreet and Bald Prairie fields. Additionally we have shallow coal bed methane producing areas in the Black Warrior Basin in Alabama and the Arkoma Basin in Oklahoma. Our production is from vertical wells in Alabama and horizontal wells in the Hartshorne Coals in Oklahoma. We have high average working interests and long life reserves in these areas. In addition, we have a 50% average working interest covering approximately 46,000 net acres of coal bed methane production operated by Black Warrior Methane Corporation in the Brookwood Field. We also have approximately 200,000 net acres in the New Albany Shale in Indiana. We are the operator of these properties and have a 95% working interest. During 2011, we sold oil and natural gas properties located in the Minden and Blue Creek fields for approximately $204 million. Additionally, we sold our New Albany Shale properties in July of 2012 for $6 million.

We invested $28 million in capital expenditures in these operations in 2011 and have allocated approximately $5 million in capital expenditures in 2012. Average production for the year ended December 31, 2011 was 147 MMcfe/d compared to 185 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our Arklatex land positions included:

• 554,000 total net acres, including approximately 351,000 net undeveloped net acres;

• 554 Bcfe of estimated net proved reserves; and

• 1,843 net producing wells.

*Raton Basin.* Our operations in the Raton Basin of northern New Mexico and southern Colorado, where we own the minerals beneath the Vermejo Park Ranch, are primarily focused on coal bed methane production. We invested $30 million in capital expenditures in these operations in 2011 and have allocated approximately $6 million in capital expenditures in 2012. Average production for the year ended December 31, 2011 was 79 MMcfe/d compared to 76 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, these operations included 606,000 total net acres (including approximately 464,000 net undeveloped acres), 552 Bcfe of estimated net proved reserves and 972 operated/net producing wells.

*Rocky Mountains.* We have a non-operated working interest in the County Line coal bed methane property in Wyoming, with additional non-production acreage in Colorado, Wyoming, North Dakota and Utah. During 2011, we sold our operated oil and natural gas properties located in the Powder River Basin in Wyoming for approximately $346 million. We invested $2 million in capital expenditures in these operations in 2011 and have allocated less than $1 million in capital expenditures in 2012. Average production for the year ended December 31, 2011 was 20 MMcfe/d compared to 33 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, these operations included 179,000 total net acres (including approximately 169,000 net undeveloped acres), 7 Bcfe of estimated net proved reserves and 82 non-operated/net producing wells.

*Eagle Ford*

*Eagle Ford Shale.* The Eagle Ford Shale is located in LaSalle, Webb, Atascosa and Dimmit counties. Our leasing efforts began early in the play in 2008, resulting in a relatively low per acre entry cost. The Eagle Ford central programs are currently the most economic programs in our portfolio, with approximately 50% of our total net acres located in this area.

We have a history of delivering improved capital performance in the Eagle Ford Shale. In 2011, our average capital costs per well in Eagle Ford were $9.6 million, with a best of $7.7 million, as compared to average capital costs of $9.8 million for the first three wells in the location. In addition, our 2011 average cycle time per well was 23 days, with a best of 14 days, as compared to an average cycle time of 38 days for the first three wells in the location.

During 2011, we operated an average of three drilling rigs and invested $626 million in capital expenditures in our Eagle Ford Shale. In late 2011, we also sold oil and natural gas properties located in the Frio county area for approximately $26 million. Average net production for the year ended December 31, 2011 was 40 MMcfe/d compared to 6 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, our properties in the Eagle Ford Shale included:

• 157,000 total net acres, including approximately 151,000 undeveloped net acres;

• 642 Bcfe of estimated net proved reserves; and

• 64 net producing wells.

We have allocated approximately $896 million in capital expenditures to our Eagle Ford Shale program in 2012.

*Southern*

In our Southern division, our focus has primarily been on developing and exploring for oil and natural gas in unconventional shales and tight gas sands in south and west Texas. These opportunities have been characterized by lower risk, longer life production profiles. Prior to selling our Gulf of Mexico assets in July 2012, our operations in this area were focused on conventional reservoirs characterized by relatively high initial production rates, resulting in higher near-term cash flows and high decline rates. For the first six months of 2012, daily production for the Southern division averaged 120 MMcfe. During 2011, we invested $181 million on capital projects and production averaged 127 MMcfe/d in the Southern division.

*Wolfcamp Shale.* The Wolfcamp Shale is our key program in the Southern division. It is located in the Permian Basin in Reagan, Crockett, Upton and Irion Counties, Texas. Since 2010, we have grown our position in this area to approximately 138,000 net acres.

During 2011, we operated an average of two drilling rigs and invested $163 million in capital expenditures in our Wolfcamp Shale. Average net production for the year ended December 31, 2011 was 3 MMcfe/d. As of December 31, 2011, our properties in the Wolfcamp Shale included:

• 138,000 total net acres, including approximately 135,000 undeveloped net acres;

• 148 Bcfe of estimated net proved reserves; and

• 14 net producing wells.

We have allocated approximately $204 million in capital expenditures to our Wolfcamp Shale program in 2012.

*Texas Gulf Coast/Gulf of Mexico.* Our assets in the Texas Gulf Coast include the Renger, Dry Hollow, Brushy Creek and Speaks fields, located in Lavaca County, the Graceland Field, located in Colorado County, and the Vicksburg/Frio area, with concentrated and contiguous assets in the Jeffress and Monte Christo fields, primarily in Hidalgo County. These assets also include assets in the Alvarado and Kelsey fields, in Starr and Brooks Counties, and working interests in the Bob West, Jennings Ranch and Roleta fields, located in Zapata County. Other interests in Zapata County include the Bustamante and Las Comitas fields.

Our assets in the Gulf of Mexico area included interests in 69 Blocks south of the Louisiana, Texas and Alabama shoreline focused on deep (greater than 12,000 feet) oil and natural gas reserves in relatively shallow water depths (less than 400 feet). In these areas, we licensed over 8,700 square miles of three dimensional (3D) seismic data onshore and over 61,000 square miles of 3D seismic data offshore.

We invested $18 million in capital expenditures in these operations in 2011 and have allocated approximately $11 million in capital expenditures in 2012. Average production for the year ended December 31, 2011 was 124 MMcfe/d compared to 183 MMcfe/d for the year ended December 31, 2010. As of December 31, 2011, these operations included 314,000 total net acres (including approximately 168,000 net undeveloped acres), 326 Bcfe of estimated net proved reserves and 785 operated/net producing wells. We sold our Gulf of Mexico operations in July of 2012.

*Four Star*

We have an approximate 49% equity interest in Four Star. Four Star operates in the San Juan, Permian, Hugoton and South Alabama basins and in the Gulf of Mexico. Production is from high quality conventional and CBM assets in several basins. During 2011, our equity interest share of Four Star’s daily equivalent natural gas production averaged approximately 61 MMcfe/d.

***International***

*Brazil*

Our Brazilian operations cover approximately 132,000 net acres in the Espirito Santo, Potiguar and Camamu basins located in offshore Brazil. During 2011, we invested $19 million on capital projects in Brazil, and production averaged 34 MMcfe/d. As of December 31, 2011, we have total capitalized costs of approximately $205 million attributable to our operations in Brazil. Our operations in each basin are described below:

• *Espirito Santo Basin.* We own an approximate 24% working interest in the Camarupim Field. We have four wells producing in the field, and production in the Camarupim Field averaged approximately 27 MMcfe/d in 2011. We also own a 35% working interest in two areas that are under plans of evaluation, originating from the ES-5 block, which are operated by Petrobras. During 2011 we also released approximately $86 million of unevaluated capitalized costs into the Brazilian cost pool related to the ES-5 block upon the completion of our evaluation of exploratory wells drilled in 2009 and 2010 that were not additive to our proved reserves.

• *Potiguar Basin.* We own a 35% working interest in the Pescada‑Arabaiana fields. Our production from these fields averaged approximately 7 MMcfe/d in 2011.

• *Camamu Basin.* We own a 100% working interest in two development areas, the Pinauna and Camarao fields. During 2011, we were informed that our environmental permit request for the Pinauna Field in the Camamu Basin was denied by the Brazilian environmental regulatory agency. As a result, we released $94 million of unevaluated capitalized costs related to this field into the Brazilian full cost pool. We have filed an appeal with respect to the denial of this permit and are awaiting a response with respect thereto.

We own a 20% interest in two additional blocks in the Camamu Basin, CAL-M-312 and CAL-M-372. During 2011, we relinquished our 18% working interest in the BM-CAL-5 block which is owned by Petrobras, Brazil’s state‑owned energy company.

*Egypt*

Prior to the sale of our interests in Egypt in June 2012, we had approximately 774,000 net acres in two blocks located onshore in Egypt’s Western Desert. We owned a 60 percent working interest in the South Mariut block, which contained approximately 497,000 net acres and a 50 percent working interest in the South Alamein block, which contained approximately 277,000 net acres. As of December 31, 2011 we had total capitalized costs in Egypt of approximately $74 million.

***Key Program Profiles***

The following table describes the characteristics of an average well for the respective key areas based on our 2012 capital program and internal engineering estimates (dollars in millions):

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Capital Costs(1)** | **Estimated Ultimate Recovery (Mboe)(1)** | **Initial Production (Boe/d)(1)(2)** | **IRR(3)** | **Average Working Interest** | **Average Net Revenue Interest** |
| Eagle Ford Shale, Central | $8.0 - 8.4 | 500 - 600 | 750 - 900 | 45 - 65% | 92% | 69% |
| Wolfcamp Shale | 8.0 - 8.4 | 465 - 510 | 575 - 675 | 20 - 30 | 100 | 75 |
| Altamont Field | 4.6 - 7.7 | 300 - 450 | 400 - 600 | 20 - 40 | 89 | 75 |
| South Louisiana Wilcox | 6.0 - 7.0 | 320 - 440 | 500 - 900 | 30 - 70 | 85 | 64 |

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Gross Capital Costs(1)** | **Estimated Gross Ultimate Recovery (Bcfe)(1)** | **Initial Production (MMcfe/d)(1)(2)** | **IRR(3)** | **Average Working Interest** | **Average Net Revenue Interest** |
| Haynesville Shale, Holly | $7.9 - 8.3 | 5.4 - 7.1 | 15 - 19 | 12 - 29% | 80% | 67% |

(1) Based on 100% working interest and net revenue interest basis.

(2) Based on initial 24 hours of production.

(3) After tax internal rate of return net to our interest based on $3.50 per MMBtu Henry Hub pricing and $90.00 per Bb1 WTI pricing.

**Oil and Gas Properties**

***Oil and Condensate, Natural Gas and NGL Reserves and Production***

The table below presents information about our proved reserves as of December 31, 2011. These reserves 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. Certain risks and uncertainties associated with estimating proved oil and natural gas reserves are discussed further in “Risk Factors” and elsewhere herein Net proved reserves exclude royalties and interests owned by others and reflect contractual arrangements and royalty obligations in effect at December 31, 2011.

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Net Proved Reserves** | | | | |  |
|  | **Natural Gas** | **Oil/ Condensate** | **NGLs** | **Total** | | **2011 Production** |
|  | **(MMcf)** | **(MBbls)** | **(MBbls)** | **(Mmcfe)** | **(Percent)** | **(MMcfe)** |
| *Reserves and Production by Division* |  |  |  |  |  |  |
| Consolidated: |  |  |  |  |  |  |
| Proved |  |  |  |  |  |  |
| U.S. |  |  |  |  |  |  |
| Central | 2,176,021 | 70,995 | — | 2,601,991 | 65% | 210,272 |
| Eagle Ford | 91,271 | 82,750 | 9,092 | 642,321 | 16% | 14,550 |
| Southern | 298,574 | 24,056 | 5,153 | 473,830 | 12% | 46,335 |
| Total | 2,565,866 | 177,801 | 14,245 | 3,718,142 | 93% | 271,157 |
| Brazil | 81,325 | 2,269 | — | 94,942 | 3% | 12,539 |
| Total Consolidated | 2,647,191 | 180,070 | 14,245 | 3,813,084 | 96% | 283,696 |
| Unconsolidated Affiliate(1) | 134,713 | 1,569 | 4,908 | 173,574 | 4% | 22,052 |
| Total Combined | 2,781,904 | 181,639 | 19,153 | 3,986,658 | 100% | 305,748 |
| *Reserves by Classification* |  |  |  |  |  |  |
| Consolidated: |  |  |  |  |  |  |
| Proved Developed |  |  |  |  |  |  |
| U.S. | 1,488,045 | 46,797 | 5,168 | 1,799,831 | 47% |  |
| Brazil | 81,325 | 2,269 | — | 94,942 | 3% |  |
| Total | 1,569,370 | 49,066 | 5,168 | 1,894,773(2) | 50% |  |
| Proved Undeveloped |  |  |  |  |  |  |
| U.S. | 1,077,821 | 131,004 | 9,077 | 1,918,311 | 50% |  |
| Brazil | — | — | — | — | 0% |  |
| Total | 1,077,821 | 131,004 | 9,077 | 1,918,311 | 50% |  |
| Total Consolidated | 2,647,191 | 180,070 | 14,245 | 3,813,084(2) | 100% |  |
| Unconsolidated Affiliate:(1) |  |  |  |  |  |  |
| Proved Developed | 116,029 | 1,520 | 4,066 | 149,540 | 86% |  |
| Proved Undeveloped | 18,684 | 49 | 842 | 24,034 | 14% |  |
| Unconsolidated Affiliate(1) | 134,713 | 1,569 | 4,908 | 173,574 | 100% |  |
| Total Combined | 2,781,904 | 181,639 | 19,153 | 3,986,658 | 100% |  |

(1) Amounts represent our approximate 49% equity interest in Four Star.

(2) Includes 1,550 Bcfe of proved developed producing reserves representing 41% of consolidated proved reserves and 345 Bcfe of proved developed non-producing reserves representing 9% of consolidated proved reserves at December 31, 2011.

Our consolidated reserves in the table above are consistent with estimates of reserves filed with 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.

The table below presents proved reserves as reported and sensitivities related to our proved reserves based on differing price scenarios as of December 31, 2011.

|  |  |
| --- | --- |
|  | **Net Proved Reserves (MMcfe)** |
| As Reported |  |
| Consolidated | 3,813,084 |
| Unconsolidated Affiliate | 173,574 |
| Total Combined | 3,986,658 |
| 10% increase in commodity prices(1) |  |
| Consolidated | 3,836,145 |
| Unconsolidated Affiliate | 175,991 |
| Total Combined | 4,012,136 |
| 10% decrease in commodity prices(1) |  |
| Consolidated | 3,614,145 |
| Unconsolidated Affiliate | 170,007 |
| Total Combined | 3,784,152 |

(1) Based on the first day 12-month average U.S. prices of $96.19 per barrel of oil and $4.12 per MMBtu of natural gas used to determine proved reserves at December 31, 2011.

Current natural gas prices are significantly below the 12-month average price used to determine our domestic proved reserves at December 31, 2011. A sustained period of low domestic natural gas prices will over time result in a downward revision of proved reserves and a corresponding reduction in the discounted future net cash flows from our proved reserves.

We employ a technical staff of engineers and geoscientists to 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, our unconsolidated affiliate, has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers. He is currently responsible for reserve reporting, strategy development, technical excellence and land administration. He has more than 24 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 proved reserves prepared by us as of December 31, 2011. In connection with its audit, Ryder Scott reviewed 86% of the properties associated with our total proved reserves on a natural gas equivalent basis, representing 87% 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, 2011. In connection with the audit of these proved reserves, Ryder Scott reviewed 87% of the properties associated with Four Star’s total proved reserves on a natural gas equivalent basis, representing 91% of the total discounted future net cash flows. For the reviewed properties, our overall proved reserves estimates are within 10% of Ryder Scott’s estimates.

The technical person primarily responsible for overseeing the reserves audit by Ryder Scott has a B.S. degree in mechanical engineering. He is a Licensed Professional Engineer in the State of Texas, a member of the Society of Petroleum Engineers and has more than 20 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. Our reserve data contained in this prospectus assumes that we can and will make these expenditures and conduct these operations successfully, but future events, including commodity price changes and other events described under “Risk Factors” and elsewhere in this prospectus 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.

We currently have 1,474 proved undeveloped drilling locations, of which 575 are in shale plays where we are actively developing reserves. The three shales are Haynesville, Eagle Ford and Wolfcamp. At this time we do not have a developed to undeveloped relationship that is beyond one adjacent offset to a productive well.

We assess our PUD reserves on a quarterly basis. At December 31, 2011, we had 1,918 Bcfe of consolidated PUD reserves representing an increase of 662 Bcfe of PUD reserves compared to December 31, 2010. During 2011, we added 939 Bcfe of PUD reserves primarily due to our drilling activities in the Haynesville Shale in our Central division and the Eagle Ford and Wolfcamp Shales in our Southern division. We had 210 Bcfe of PUD reserves transferred to proved developed reserves and negative revisions of 11 Bcfe related to reserves older than five years as well as 20 Bcfe related to prices and performance. We divested 36 Bcfe PUD reserves from the sales of assets throughout the year in our Central, Southern and Western divisions.

We spent approximately $601 million, $199 million and $186 million, during 2011, 2010 and 2009, respectively, to convert approximately 17% or 210 Bcfe, 11% or 94 Bcfe and 11% or 69 Bcfe, respectively, of our prior year-end PUD reserves to proved developed reserves. In our December 31, 2011 reserve report, the amounts estimated to be spent in 2012, 2013 and 2014 to develop our consolidated worldwide PUD reserves are $1,003 million, $1,009 million and $1,329 million, respectively. The upward trend in the amounts estimated to be spent to develop our PUD reserves is a result of our shift in capital focus to develop our key 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 1,918 Bcfe of PUD reserves at December 31, 2011, we have 49 Bcfe of undeveloped reserves that are outside of our current five-year development plan in the Raton Basin located in northern New Mexico and southern Colorado. These reserves extend beyond the five-year development plan due to pace restrictions established by the surface owner which limits the number of wells drilled annually to a level significantly below the historical levels of wells drilled per year. Additionally, we own the mineral rights on the acreage in the Raton Basin which enables us to develop beyond the five-year window. We have historical and ongoing drilling and development activities in this area, including the drilling of 30 undeveloped locations in 2011 and a 30 to 50 well development program in 2013. There were no new PUD reserves booked to the Raton Basin in 2011, and the undeveloped reserves outside of our current five-year development plan represent less than 5% of the consolidated PUD reserves.

***Acreage and Wells***

The following tables detail (i) our interest in developed and undeveloped acreage at December 31, 2011, (ii) our interest in oil and natural gas wells at December 31, 2011 and (iii) our exploratory and development wells drilled during the years 2009 through 2011. 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* |  |  |  |  |  |  |
| United States |  |  |  |  |  |  |
| Central | 641,599 | 496,279 | 1,570,857 | 1,242,077 | 2,212,456 | 1,738,356 |
| Eagle Ford | 6,600 | 6,552 | 159,564 | 150,510 | 166,164 | 157,061 |
| Southern | 264,304 | 149,160 | 343,788 | 303,049 | 608,092 | 452,210 |
| Total United States | 912,503 | 651,991 | 2,074,209 | 1,695,636 | 2,986,712 | 2,347,627 |
| Brazil | 47,377 | 14,492 | 458,519 | 117,344 | 505,896 | 131,836 |
| Egypt | — | — | 1,382,856 | 774,195 | 1,382,856 | 774,195 |
| Worldwide Total | 959,880 | 666,483 | 3,915,584 | 2,587,175 | 4,875,464 | 3,253,658 |

(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.

In the United States, our net developed acreage is concentrated primarily in New Mexico (19%), Utah (18%), the Gulf of Mexico (13%), Texas (12%), Louisiana (11%), Oklahoma (11%) and Alabama (8%). Our net undeveloped acreage is concentrated primarily in New Mexico (26%), Texas (19%), Indiana (11%), Louisiana (10%), the Gulf of Mexico (9%) and Colorado (7%). Approximately 10%, 21% and 10% of our total United States net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012, 2013 and 2014, respectively. Approximately 6% of our total Brazilian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012. Approximately 13% and 27% of our total Egyptian net undeveloped acreage is held under leases that have minimum remaining primary terms expiring in 2012 and 2013, 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 December 31, 2011(1)** | |
|  | **Gross(2)** | **Net(3)** | **Gross(2)** | **Net(3)** | **Gross(2)** | **Net(3)(4)** | **Gross(2)** | **Net(3)** |
| *Productive Wells* |  |  |  |  |  |  |  |  |
| United States |  |  |  |  |  |  |  |  |
| Central | 4,468 | 3,007 | 436 | 297 | 4,904 | 3,304 | 20 | 13 |
| Eagle Ford | 4 | 4 | 60 | 60 | 64 | 64 | 16 | 16 |
| Southern | 969 | 777 | 47 | 41 | 1,016 | 818 | 7 | 7 |
| Total | 5,441 | 3,788 | 543 | 398 | 5,984 | 4,186 | 43 | 36 |
| Brazil | 9 | 2 | 5 | 2 | 14 | 4 | — | — |
| Egypt | — | — | — | — | — | — | 4 | 2 |
| Worldwide Total | 5,450 | 3,790 | 548 | 400 | 5,998 | 4,190 | 47 | 38 |

(1) Includes wells that were spud in 2011 or a prior year and have not been completed.

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

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

(4) At December 31, 2011, we operated 3,625 of the 4,190 net productive wells.

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | **Net Exploratory(1)** | | | **Net Development(1)** | | |
|  | **2011** | **2010** | **2009** | **2011** | **2010** | **2009** |
| *Wells Drilled* |  |  |  |  |  |  |
| United States |  |  |  |  |  |  |
| Productive | 87 | 35 | 61 | 95 | 55 | 69 |
| Dry | — | — | 2 | — | 2 | 2 |
| Total | 87 | 35 | 63 | 95 | 57 | 71 |
| Brazil |  |  |  |  |  |  |
| Productive | — | — | — | — | — | 1 |
| Dry | 1 | — | — | — | — | — |
| Total | 1 | — | — | — | — | 1 |
| Egypt |  |  |  |  |  |  |
| Productive | — | — | — | — | — | — |
| Dry | — | — | 2 | — | — | — |
| Total | — | — | 2 | — | — | — |
| Worldwide |  |  |  |  |  |  |
| Productive | 87 | 35 | 61 | 95 | 55 | 70 |
| Dry | 1 | — | 4 | — | 2 | 2 |
| Total | 88 | 35 | 65 | 95 | 57 | 72 |

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

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

***Net Production, Sales Prices, Transportation and Production Costs***

The following table details our net production volumes, average sales prices received, average transportation costs and average production costs (including production taxes) associated with the sale of oil and natural gas for each of the years ended December 31:

|  | **2011** | **2010** | **2009** |
| --- | --- | --- | --- |
| *Volumes:* |  |  |  |
| Consolidated Net Production Volumes |  |  |  |
| United States |  |  |  |
| Natural gas (MMcf)(1) | 230,669 | 215,905 | 214,718 |
| Oil and condensate (MBbls)(1) | 5,680 | 4,363 | 3,978 |
| NGL (MBbls) | 1,068 | 1,423 | 1,570 |
| Total (MMcfe) | 271,157 | 250,621 | 248,006 |
| Brazil |  |  |  |
| Natural gas (MMcf) | 10,414 | 9,706 | 3,826 |
| Oil and condensate (MBbls) | 354 | 384 | 100 |
| NGL (MBbls) | — | — | — |
| Total (MMcfe) | 12,539 | 12,010 | 4,426 |
| Consolidated—Worldwide |  |  |  |
| Natural gas (MMcf) | 241,083 | 225,611 | 218,544 |
| Oil and condensate (MBbls) | 6,034 | 4,747 | 4,078 |
| NGL (MBbls) | 1,068 | 1,423 | 1,570 |
| Total (MMcfe) | 283,696 | 262,631 | 252,432 |
| Total (MMcfe/d) | 777 | 720 | 691 |
| Unconsolidated Affiliate Volumes(2) |  |  |  |
| Natural gas (MMcf) | 16,881 | 17,165 | 19,557 |
| Oil and condensate (MBbls) | 306 | 364 | 419 |
| NGL (MBbls) | 556 | 573 | 678 |
| Total equivalent volumes (MMcfe) | 22,052 | 22,787 | 26,139 |
| MMcfe/d | 61 | 62 | 72 |
| Total Combined Volumes(2) |  |  |  |
| Natural gas (MMcf) | 257,964 | 242,776 | 238,101 |
| Oil and condensate (MBbls) | 6,340 | 5,111 | 4,497 |
| NGL (MBbls) | 1,624 | 1,996 | 2,248 |
| Total equivalent volumes (MMcfe) | 305,748 | 285,418 | 278,571 |
| MMcfe/d | 838 | 782 | 763 |
| *Consolidated Prices and Costs per Unit:* |  |  |  |
| Natural Gas Average Realized Sales Price ($/Mcf) |  |  |  |
| United States |  |  |  |
| Physical sales | $3.91 | $4.26 | $3.78 |
| Including financial derivative settlements(3) | 5.37 | 5.71 | 7.68 |
| Brazil |  |  |  |
| Physical sales | 6.94 | 5.65 | 4.84 |
| Including financial derivative settlements(3) | 6.94 | 4.93 | 4.22 |
| Worldwide |  |  |  |
| Physical sales | 4.04 | 4.32 | 3.80 |
| Including financial derivative settlements(3) | 5.44 | 5.67 | 7.62 |
| Oil and Condensate Average Realized Sales Price ($/Bbl) |  |  |  |
| United States |  |  |  |
| Physical sales | 90.22 | 72.37 | 52.27 |
| Including financial derivative settlements(3) | 88.98 | 70.52 | 96.44 |
| Brazil |  |  |  |
| Physical sales | 110.33 | 78.02 | 60.88 |
| Including financial derivative settlements(3) | 110.33 | 78.02 | 60.88 |
| Worldwide |  |  |  |
| Physical sales | 91.40 | 72.83 | 52.48 |
| Including financial derivative settlements(3) | 90.23 | 71.13 | 95.57 |
| NGL Average Realized Sales Price ($/Bbl) |  |  |  |
| United States |  |  |  |
| Physical sales | 53.50 | 42.38 | 33.75 |
| Brazil |  |  |  |
| Physical sales | — | — | — |
| Worldwide |  |  |  |
| Physical sales | 53.50 | 42.38 | 33.75 |
| Average Transportation Costs |  |  |  |
| United States |  |  |  |
| Natural gas ($/Mcf) | 0.35 | 0.31 | 0.28 |
| Oil and Condensate ($/Bbl) | 0.06 | 0.09 | 0.06 |
| NGL ($/Bbl) | 3.83 | 3.16 | 2.61 |
| Worldwide |  |  |  |
| Natural gas ($/Mcf) | 0.33 | 0.30 | 0.28 |
| Oil and Condensate ($/Bbl) | 0.06 | 0.08 | 0.06 |
| NGL ($/Bbl) | 3.83 | 3.16 | 2.61 |
| Average Production Costs (Lease Operating Expenses ($/Mcfe) |  |  |  |
| United States | 0.65 | 0.62 | 0.70 |
| Brazil(4) | 3.29 | 3.07 | 5.19 |
| Worldwide(4) | 0.77 | 0.73 | 0.78 |
| Average Production Taxes ($/Mcfe) |  |  |  |
| United States | 0.26 | 0.21 | 0.21 |
| Brazil | 0.91 | 0.73 | 0.68 |
| Worldwide | 0.28 | 0.27 | 0.22 |

(1) For the years ended December 31, 2011 and 2010, our Eagle Ford Shale program had natural gas volumes of 1,971 MMcf and 287 MMcf, oil and condensate volumes of 1,690 MMBbls and 177 MMBbls and NGL volumes of 207 MMBbls and 30 MMBbls, respectively. For the years ended December 31, 2011, 2010 and 2009, our Haynesville Shale program, within the Central division, had natural gas volumes of 80,591 MMcf, 42,820 MMcf and 11,223 MMcf, and NGL volumes of less than 2 MMBbls, 2 MMBbls and 1 MMBbls, respectively. The Haynesville Shale program had oil and condensate volumes of less than 1 MMBbls for the year ended December 31, 2011.

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

(3) We had no cash premiums related to oil derivatives settled during the years ended December 31, 2011, 2010 and 2009. Premiums paid in 2009 related to natural gas derivatives settled during the year ended December 31, 2010 were $157 million. Premiums paid related to natural gas derivatives settled during the year ended December 31, 2011 were $23 million. Had we included these premiums in our natural gas average realized prices in 2011 and 2010, our realized price, including financial derivatives settlements, would have decreased by $0.10/Mcf and $0.70/Mcf for the years ended December 31, 2011 and 2010.

(4) Includes approximately $14 million of start-up costs in Camarupim Field in 2009 or $3.08 per Mcfe for Brazil and $0.05 per Mcfe worldwide.

***Acquisition, Development and Exploration Expenditures***

The following table details information regarding our capital expenditures in our acquisition, development and exploration activities for each of the years ended December 31:

|  |  |  |  |
| --- | --- | --- | --- |
|  | **2011** | **2010** | **2009** |
| United States |  |  |  |
| Acquisition Costs: |  |  |  |
| Proved | $— | $51 | $87 |
| Unproved | 45 | 269 | 89 |
| Development Costs | 694 | 276 | 324 |
| Exploration Costs: |  |  |  |
| Delay rentals | 8 | 9 | 5 |
| Seismic acquisition and reprocessing | 32 | 15 | 27 |
| Drilling | 818 | 576 | 323 |
| Asset Retirement Obligations | 25 | 7 | 36 |
| Total full cost pool expenditures | 1,622 | 1,203 | 891 |
| Non-full cost pool expenditures | 18 | 35 | 34 |
| Total capital expenditures | $1,640 | $1,238 | $925 |
| Brazil and Egypt(1) |  |  |  |
| Acquisition Costs: |  |  |  |
| Unproved | $— | $— | $51 |
| Development Costs | 12 | 28 | 118 |
| Exploration Costs: |  |  |  |
| Seismic acquisition and reprocessing | 9 | 6 | 3 |
| Drilling | 6 | 52 | 64 |
| Asset Retirement Obligations | — | — | 6 |
| Total full cost pool expenditures | 27 | 86 | 242 |
| Non-full cost pool expenditures | 2 | 1 | 4 |
| Total capital expenditures | $29 | $87 | $246 |
| Worldwide(1) |  |  |  |
| Acquisition Costs: |  |  |  |
| Proved | $— | $51 | $87 |
| Unproved | 45 | 269 | 140 |
| Development Costs | 706 | 304 | 442 |
| Exploration Costs: |  |  |  |
| Delay rentals | 8 | 9 | 5 |
| Seismic acquisition and reprocessing | 41 | 21 | 30 |
| Drilling | 824 | 628 | 387 |
| Asset Retirement Obligations | 25 | 7 | 42 |
| Total full cost pool expenditures | 1,649 | 1,289 | 1,133 |
| Non-full cost pool expenditures | 20 | 36 | 38 |
| Total capital expenditures | $1,669 | $1,325 | $1,171 |

(1) Total capital expenditures for Egypt were $8 million, $20 million and $81 million for the years ended December 31, 2011, 2010 and 2009, respectively.

**Markets and Competition**

We primarily sell our domestic oil and natural gas to third parties at spot market prices, subject to customary adjustments. We sell our NGL at market prices under monthly or long-term contracts, subject to customary adjustments. We have a highly experienced marketing team in place and strive to achieve best available pricing for sales from all of our production.

In Brazil, we sell the majority of our oil and natural gas under long-term contracts to Petrobras. These long-term contracts include a gas sales agreement and a condensate sales agreement. The gas sales agreement provides for a price that adjusts quarterly based on a basket of fuel oil prices, while the condensate sales agreement provides for a price that adjusts monthly based on a Brent crude price less a fixed differential that will adjust annually. The gas sales agreement also includes a minimum daily delivery commitment of our natural gas production. The current delivery commitment is approximately 15 MMcf/d and can be modified on an annual basis depending on the production capacity of the subject wells. We do not anticipate being unable to meet the current delivery commitment. We enter into derivative contracts on our oil and natural gas production to stabilize our cash flows, reduce the risk and financial impact of downward commodity price movements and protect the economic assumptions associated with our capital investment programs. For a further discussion of these contracts, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Price Risk Management Activities.”

The exploration and production industry is highly competitive in the search for and acquisition of oil and natural gas reserves and in the sale of oil, natural gas and NGL. 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.

**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 in 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 DOI that currently impose liability upon lessees for the cost of environmental impacts resulting from their operations. Royalty obligations on all federal leases are regulated by the Office of Natural Resources Revenue within the DOI, which has promulgated valuation guidelines for the payment of royalties by producers. Our exploration and production operations in Brazil are subject to environmental (and other) regulations administered by the Brazilian government, which include political subdivisions. These domestic and international laws and regulations affect the construction and operation of facilities, water disposal, drilling operations, production and future lease sales.

***Hydraulic Fracturing***

Hydraulic fracturing is the well stimulation technique we use to maximize productivity of our oil and natural gas wells in many of our domestic basins, including in our Haynesville, Eagle Ford, Wolfcamp, Altamont, South Louisiana Wilcox, Texas Gulf Coast, Raton and Black Warrior operations. We currently do not use hydraulic fracturing in our Arkoma program. Our net acreage position in basins in which hydraulic fracturing is utilized total approximately 2 million acres. Approximately 98% of our domestic proved undeveloped oil and natural gas reserves are subject to hydraulic fracturing. During 2011, we incurred costs of approximately $400 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, both voluntarily and under certain states’ regulations, disclosure of our hydraulic fracturing fluids through the Groundwater Protection Council’s FracFocus web site.

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 and include the following measures:

• Our drilling process executes several repeated cycles conducted in sequence—drill, set casing, cement casing and then test casing and cement for integrity before proceeding to the next drilling interval.

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

• Surface casing is set within the conductor casing and is cemented in place. Surface casing is set for all wells. The purpose of the surface casing is to contain wellbore fluids and pressure 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 USDW contact.

• 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 (a) cementing above any hydrocarbon bearing zone and (b) performing casing pressure and other tests to verify the integrity of the casing and cement.

• Production casing is set through the surface and intermediate through the depth of the targeted producing formation. Our standard practices include (a) pumping cement above the confining structure of the target zone and (b) 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 to ensure wellbore integrity.

• 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. As designed, this barrier 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 (i) pressure testing of casing and surface equipment, (ii) continuous monitoring of surface pressure, pumping rates, volumes of fluids and chemical concentrations, and (iii) continuous monitoring of well pressure during hydraulic fracturing operations. When any pressure differential outside the normal range of operations occurs, the pumps are promptly shut off 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 operations, we manage waste water to minimize risks and costs. Frac water or flowback water returned to the surface is typically contained in steel tanks or pits. Water that is not treated for reuse is usually piped or trucked to waste disposal injection wells, many of which we own and operate. These wells are permitted through the Underground Injection Control (“UIC”) program of the Safe Drinking Water Act. We also use commercial injection facilities for frac fluid disposal, which typically dispose of the frac fluids in permitted injection disposal wells. In Alabama, we operate a water treatment disposal facility with a permitted surface discharge. This facility is regulated under the National Pollutant Discharge Elimination System (the “NPDES”) program.

We have not received regulatory citations or notice of suits related to our hydraulic fracturing operations for environmental concerns. We have experienced no material incidents of surface spills of fluids associated with hydraulic fracturing. Consistent with local, state and federal requirements, any releases were reported to appropriate regulatory agencies and site restoration was completed. No remediation reserve has been identified or anticipated as a result of these incidents.

***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 material hydraulic fracturing well control issue.

We conduct annual training and drills for various upset scenarios. To augment our internal capability, we retain the services of vendors to assist our spill management team to the extent that we experience any prolonged and significant incidents. We also maintain contractual agreements and memberships with additional oil spill and emergency service providers and co-ops for equipment, response personnel, dispersant and aircraft, vessels, wildlife rehabilitation, and shoreline protection and cleanup.

We have an emergency response plan to address any material well control or asset issue in our onshore operations. We retain the services of experienced vendors to assist in the management of any material well control issues that might arise. Pursuant to our emergency response plan, after any well control issue is abated, we will initiate cleanup and restoration work.

Despite the existence of our procedures and plans, there is a risk that we could experience well control problems in our onshore operations. As a result, we could be exposed to regulatory fines and penalties, as well as landowner lawsuits resulting from any spills or leaks that might occur. We do not maintain insurance to cover all possible risks of loss. However, we expect to maintain liability and property damage insurance at levels customary in our industry.

In addition, we might have remedies against our contractors or vendors or our joint working interest owners with respect to any losses associated with unintended spills or leaks. For example, we typically have indemnity provisions in our service agreements with our contractors. Liability under such agreements is typically allocated such that we and our contractors assume liability for our respective personnel and property, regardless of how the loss or damage to the personnel and property may have been caused. As a result, typically our contractors are required to indemnify us for any pollution originating from facilities or equipment in their control and custody above the surface of the land. In turn, we typically indemnify our contractors for any pollution originating below the surface of the land, including resulting from fire, blowout, cratering, seepage or other uncontrolled flow of oil, gas, water, drilling fluid or other fluids and materials from wells, except to the extent caused by a contractor’s willful misconduct. Under our joint operating agreements with other working interest owners, each working interest owner is responsible for its working interest share of any liabilities arising out of joint operations, except generally in cases of gross negligence or willful misconduct by the operator.

To the extent that our well control issues might result in any injuries or fatalities, in addition to the potential insurance coverages mentioned above, we might have certain remedies against our contractors or working interest owners. Similar to property damage, our contractors assume responsibility for injury or death of their personnel arising in connection with activities conducted at our wellsites and other worksites, and our contractors are required to maintain appropriate levels of insurance against such liabilities. In addition, while we generally operate most of our properties, including jointly owned properties, in those instances where we are a non-operating party, each working interest owner in a property is required to bear its working interest share of any liability to a third party arising from such operations, and we generally would be entitled to indemnity from the operator only to the extent that we bore a disproportionate amount of the liability (in which case, we could look to the operator and any other non-operators for indemnity in respect of that portion of the liability borne by us in excess of our working interest share) or if the liability was caused by the operator’s gross negligence or willful misconduct.

**Legal Proceedings**

We 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, 2012, we had approximately $23 million accrued for all outstanding legal proceedings and other contingent matters, including $22 million of sales tax reserves.

***Sales Tax Audits.*** As a result of sales and use tax audits during 2010, the State of Texas has asserted additional taxes plus penalties and interest for the audit period 2001-2008 for two of our operating entities. We believe amounts reserved are adequate. We are currently contesting the assessments and the ultimate outcomes are still uncertain. We are indemnified by KMI if and to the extent the ultimate outcomes exceed the reserves. During the period ending June 30, 2012, the Louisiana audit was settled.

**Environmental**

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. The environmental laws and regulations to which we are subject also require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 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 Environmental Protection Agency (EPA) and several state environmental agencies have adopted regulations to regulate GHG emissions. Although the EPA has adopted a tailoring rule to regulate GHG emissions, it is not expected to materially impact our existing operations until 2016. 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 plan to execute the required modifications and testing in 2013. Our current estimated impact is approximately $3 million in capital expenditures in 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. These regulations will limit emissions from the hydraulic fracturing of certain natural gas wells and from certain equipment including compressors, storage vessels and natural gas processing plants. These regulations require reduction of flowback emissions from gas wells effective October 15, 2012 and use of “green completions” effective January 1, 2015. We are still evaluating the regulations and their impact on our operations and our financial results.

***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. At this time no adopted regulations have imposed a material impact on our hydraulic fracturing operations. In addition, various agencies, including the EPA, the Department of Interior and Department of Energy are reviewing changes in their regulations to address the environmental impacts of hydraulic fracturing operations. Until such regulations are implemented, it is uncertain what impact they might have on our operations.

***Comprehensive Environmental Response, Compensation and Liability Act (“CERCLA”) Matters.*** As part of our environmental remediation projects, we are or have received notice that we could be designated as a Potentially Responsible Party (“PRP”) with respect to one active site under the CERCLA or state equivalents. As of June 30, 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 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.

**Employees**

At September 5, 2012, we had 1,076 full-time employees, of which 63 employees are covered by collective bargaining agreements.

**MANAGEMENT**

The following table provides information regarding the executive officers of the Issuer and the members of the board of managers of Parent (the “Board”), as of September 10, 2012. The supervision of the Issuer’s management and the general course of its affairs and business operations is entrusted to the Board, which currently consists of nine members.

|  |  |  |  |
| --- | --- | --- | --- |
| **Name** |  | **Age** | **Position(s)** |
| Brent J. Smolik | | 51 | President, Chief Executive Officer and Manager |
| Clayton A. Carrell | | 46 | Executive Vice President and Chief Operating Officer |
| Joan M. Gallagher | | 48 | Senior Vice President, Human Resources and Administrative Services |
| John D. Jensen | | 43 | Executive Vice President, Operations Services |
| Dane E. Whitehead | | 51 | Executive Vice President and Chief Financial Officer |
| Marguerite N. Woung‑Chapman | | 47 | Senior Vice President, General Counsel and Corporate Secretary |
| Gregory A. Beard | | 40 | Manager |
| Joshua J. Harris | | 47 | Manager |
| Chang-Seok Jeong | | 53 | Manager |
| Pierre F. Lapeyre, Jr. | | 49 | Manager |
| David Leuschen | | 60 | Manager |
| Sam Oh | | 42 | Manager |
| Donald A. Wagner | | 49 | Manager |
| Rakesh Wilson | | 37 | Manager |

***Brent J. Smolik*** became our President and Chief Executive Officer and a manager of Parent in May 2012 upon the consummation of the Acquisition. He was previously Executive Vice President and Member of the Executive Committee of El Paso Corporation and President of our predecessor 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 Executive Committee from 2001 to 2006. Mr. Smolik also serves on the boards of the American Exploration and Production Council, America’s Natural Gas Alliance and the Independent Petroleum Association of America.

***Clayton A. Carrell*** became our Executive Vice President and Chief Operating Officer in May 2012 upon the consummation of the Acquisition. He was previously Senior Vice President, Chief Engineer of our predecessor since June 2010. Mr. Carrell joined El Paso Corporation in March 2007 as Vice President, Texas Gulf Coast Division. Prior to that, he was Vice President, Engineering & Operations at Peoples Energy Production from February 2001 to March 2007. Prior to joining Peoples Energy Production, Mr. Carrell worked at Burlington Resources and ARCO Oil and Gas Company from May 1988 to February 2001 in various domestic and international engineering and management roles. He serves on the Industry Board of the Texas A&M Petroleum Engineering Department, is a member of the Society of Petroleum Engineers and a Board Member of the US Oil & Gas Association.

***Joan M. Gallagher*** became our Senior Vice President, Human Resources and Administrative Services in May 2012 upon the consummation of the Acquisition. 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. In that capacity, Ms. Gallagher had HR responsibility for our predecessor’s exploration and production business unit and from January 2010 to February 2011, she had added 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*** became our Executive Vice President, Operations Services in May 2012 upon the consummation of the Acquisition. He was previously Senior Vice President, Operations of our predecessor since June 2010. From May 2009 until May 2010 he served as Vice President of Operations of our predecessor. Mr. Jensen previously served as Vice President, Strategy and Engineering from April 2007 to May 2009. Prior to joining our predecessor, 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 and a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

***Dane E. Whitehead*** became our Executive Vice President and Chief Financial Officer in May 2012 upon the consummation of the Acquisition. 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 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*** became our Senior Vice President, General Counsel and Corporate Secretary in May 2012 upon the consummation of the Acquisition. 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.

***Gregory A. Beard*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. Mr. Beard joined Apollo Management in 2010 as the Global Head of Natural Resources, based in the New York office. Mr. Beard joined Apollo Management 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 Athlon Energy, Belden & Blake Corporation, Canera Resources, Cobalt International Energy, Eagle Energy, Legend Natural Gas I ‑ IV, Mariner Energy, Phoenix Exploration, 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.

***Joshua J. Harris*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. 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., LyondellBasell Industries, CEVA Group plc, Momentive Performance Materials and the holding company for Alcan Engineered Products and is the Managing Partner of the Philadelphia 76ers. Mr. Harris has previously served on the boards of directors of Verso Paper, Metals USA, Nalco, Allied Waste Industries, Pacer International, General Nutrition Centers, Furniture Brands International, Compass Minerals Group, Alliance Imaging, NRT Inc., Covalence Specialty Materials, United Agri Products, Quality Distribution, Whitmire Distribution, and Noranda Aluminum. 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 MBA from the Harvard Business School, where he graduated as a Baker and Loeb Scholar.

***Chang-Seok Jeong*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. Mr. Jeong joined KNOC in 1986. He is currently Executive Vice President for the America Group of KNOC. Prior to this role, Mr. Jeong was Managing Director of KNOC Vietnam. Before this, Mr. Jeong was Vice President of KNOC’s Asia Production Department and Senior Manager of the New Ventures team. Mr. Jeong received his bachelor degree in Petroleum & Mining Engineering from Seoul National University, a master degree in Petroleum Engineering from Seoul National University and a PhD ABD in Petroleum Engineering from Seoul National University.

***David Leuschen*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. Mr. Leuschen is a founder and Senior Managing Director of Riverstone. Prior to co-founding Riverstone, Mr. Leuschen was a Partner and Managing Director at Goldman, Sachs & Co. and founder and head of the Goldman, Sachs & Co. Global Energy & Power Group. Mr. Leuschen joined Goldman, Sachs & Co. in 1977 and became head of the Global Energy & Power Group in 1985 and a Partner in 1986. He remained with Goldman, Sachs & Co. until leaving to found Riverstone. Mr. Leuschen has served as a director of Cambridge Energy Research Associates, Cross Timbers Oil Company (predecessor to XTO Energy), J. Aron Resources, Mega Energy, Inc. and Natural Meats Montana. He currently serves on the boards of directors of Legend Natural Gas, Dynamic Industries, Canera Resources and Titan Operating. He is also president of Switchback Ranch LLC and has served on a number of non-profit boards of directors. Mr. Leuschen received his Bachelor of Arts from Dartmouth and his Master of Business Administration from Dartmouth’s Amos Tuck School of Business.

***Pierre F. Lapeyre, Jr.*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. Mr. Lapeyre is a founder and Senior Managing Director of Riverstone. Prior to co-founding Riverstone, Mr. Lapeyre was a Managing Director at Goldman, Sachs & Co. in its Global Energy & Power Group. Mr. Lapeyre joined Goldman, Sachs & Co. in 1986 and spent his 14-year investment banking career focused on energy and power, particularly the midstream/pipeline and oil service sectors. Mr. Lapeyre’s responsibilities included client coverage and leading the execution of a wide variety of mergers and acquisitions, initial public offerings, strategic advisory and capital markets financings for clients across all sectors of the industry. Mr. Lapeyre serves on the boards of directors of Legend Natural Gas, Titan Specialties, Dynamic Industries, Titan Operating, Three Rivers and Quorum Technologies. Mr. Lapeyre received his Bachelor of Science in Finance and Economics from the University of Kentucky and his Master of Business Administration from the University of North Carolina at Chapel Hill.

***Sam Oh*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. Mr. Oh joined Apollo Management in 2008. He is a Senior Partner and one of the original founding members of Apollo’s Natural Resources Group. Prior to that time, 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 Management, Mr. Oh has been actively involved in Apollo’s E&P investments, including leading the Parallel Petroleum acquisition in 2009. Mr. Oh was formerly Chairman of the Board of Parallel Petroleum and is a Director of Athlon Energy. Mr. Oh received a BS from the University of Pennsylvania’s Wharton School of Business and an MBA from the Yale School of Management. He is also a Certified Public Accountant and a Chartered Financial Analyst.

***Donald A. Wagner*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. 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.

***Rakesh Wilson*** became a manager of the Parent in May 2012 upon the consummation of the Acquisition. Mr. Wilson joined Apollo Management in 2009, where he is currently a senior member of the natural resources team. Prior to joining Apollo Management, 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 with deals including Wellbore Capital and Helios Energy/Royalty Partners. 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 MBA from INSEAD, Fontainebleau, France. He has also taught business courses at universities in China.

**Committees of the Board of Managers**

***Audit Committee.*** The Audit Committee consists of seven members: Messrs. Oh (as Chairman), Beard, Harris, Jeong, Lapeyre, Wagner and Wilson. In light of our status as a privately-held company and the absence of a public trading market for our common stock, there are no requirements that we have an independent audit committee and our Board has not designated any member of the Audit Committee as an “audit committee financial expert”.

***Compensation Committee.*** The Compensation Committee consists of seven members: Messrs. Oh (as Chairman), Beard, Harris, Jeong, Leuschen, Wagner and Wilson. The Compensation Committee is responsible for formulating, evaluating and approving the compensation and employment arrangements of the senior officers of the Issuer.

***Budget Committee.*** The Budget Committee consists of two members: Messrs. Lapeyre and Oh. The Budget Committee is responsible for authorizing certain capital expenditures, acquisitions and dispositions by the Issuer and its subsidiaries.

**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*.

**Executive Compensation**

***Compensation Discussion and Analysis***

The following compensation discussion and analysis, or *CD&A*, provides information relevant to understanding the 2011 compensation of the executive officers identified in the Summary Compensation Table below, who we refer to 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. Unless otherwise noted, the information provided in this CD&A reflects compensation earned by our named executive officers while employed by El Paso Corporation (“El Paso”) pursuant to the design and objectives of El Paso’s executive compensation programs in place prior to the closing of the sale of EP Energy to EPE Acquisition, LLC in May 2012. All executive compensation decisions for our named executive officers prior to the sale were made by El Paso, and to the extent applicable, the Compensation Committee of El Paso’s Board of Directors (“El Paso’s Compensation Committee”), and relate to the positions that such executives held at El Paso prior to the sale. Executive compensation decisions following the closing of the sale are made by the compensation committee of the board of our parent company, EPE Acquisition, LLC, and relate to the current positions the officers hold as executive officers of EP Energy. The discussion is divided into the following sections:

• El Paso’s Compensation Program Design and Approval Process

• 2011 Compensation Decisions

• Impact of EP Energy Sale and El Paso Merger on NEO Compensation

• Executive Compensation Programs at EP Energy

***El Paso’s Compensation Program Design and Approval Process***

**Program Design**

The core of our El Paso’s 2011 executive compensation program was pay for performance. A significant portion of each of our named executive’s total annual compensation was at risk and dependent upon El Paso’s achievement of specific, measurable performance goals. The framework of El Paso’s 2011 executive compensation program is set forth below:

• total annual compensation included three principal elements: base salary, performance‑based annual cash incentive awards, and long-term equity‑based incentives;

• El Paso’s cash-based annual incentives were tied to specific pre-established financial, operational and safety performance goals; and

• 2011 long-term incentive grants included stock options, time-vested restricted stock awards, and performance shares.

**Role of El Paso’s Compensation Committee**

El Paso’s Compensation Committee had primary responsibility for determining and approving, on an annual basis, the total compensation level of El Paso’s senior officers who were subject to Section 16(a) of the Exchange Act, which included Messrs. Smolik and Whitehead. El Paso’s Compensation Committee received information and advice from its compensation consultant as well as from El Paso’s human resources department and management to assist in compensation determinations. Management of El Paso was responsible for determining and approving the total compensation level of officers who were not subject to Section 16(a) of the Exchange Act, which included Messrs. Carrell and Jensen and Ms. Woung‑Chapman.

**Compensation Consultant**

El Paso’s Compensation Committee retained Deloitte Consulting as its independent compensation consultant. Deloitte advised the committee on an ongoing basis with regard to the general competitive landscape and trends in compensation and executive and director compensation matters, including (i) competitive benchmarking, (ii) incentive plan design, (iii) performance metrics testing, (iv) peer group selection, (v) compensation risk-management, and (vi) updates on best-practices and trends in executive and director compensation.

***2011 Compensation Decisions***

**2011 Annual Base Salaries and 2011 Target Bonus Opportunities**

Our named executive officers received base salary adjustments in early 2011. Salary increases were generally between 3% and 6%. In each situation, the salary increases were made to align with market competitive levels and reflect individual contributions. No adjustments were made to the named executive officers’ 2011 target bonus opportunities. These target bonus opportunities relate to the positions each of our named executive officers held with El Paso during 2011 and were derived in part from peer group and competitive survey benchmarking data and in part by the judgment of El Paso’s Compensation Committee and management on the internal equity of the positions, scope of job responsibilities and the executives’ industry experience and tenure. The following table sets forth the base salaries and annual target bonus opportunities for our named executive officers for 2011.

**Annual Base Salaries and**

**Target Bonus Opportunities**

|  |  |  |  |
| --- | --- | --- | --- |
| **Name** |  | **2011 Base Salary(1) ($)** | **2011 Target Bonus Opportunity (% of salary)** |
| Brent J. Smolik | | 600,000 | 90% |
| Dane E. Whitehead | | 406,008 | 60% |
| Clayton A. Carrell | | 336,000 | 45% |
| John D. Jensen | | 336,000 | 45% |
| Marguerite N. Woung‑Chapman | | 295,488 | 35% |

(1) Base salary increases were effective as of April 1, 2011.

**Annual Cash Incentive Awards for 2011 Performance**

*Performance Goals.* At the beginning of 2011, El Paso’s Compensation Committee approved corporate and business unit financial and non-financial performance goals. El Paso’s 2011 corporate financial goals, which were the primary goals used in determining the 2011 annual incentive bonuses for our named executive officers, are set forth below, including adjusted year-end results. For purposes of the performance goals, the reference to “MM” means million.

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | | **2011 Goals** | | | | |
| **Corporate Financial Goals** |  | **Threshold** | **Target** | **Maximum** | **2011 Results** | **Weighting** |
| Earnings Per Share | | $0.84 | $0.96 | $1.08 | $0.94 | 35% |
| Segment EBITDA | | $3,260 MM | $3,361 MM | $3,505 MM | $3,363 MM | 35% |
| Return on Total Capital | | 6.6% | 7.1% | 7.5% | 7.1% | 15% |
| Debt (net of cash) | | $13,200 MM | $12,700 MM | $12,400 MM | $12,381 MM | 15% |

The corporate financial goals were set in alignment with El Paso’s 2011 strategic plan. In making the determination of the threshold, target and maximum levels, El Paso’s Compensation Committee considered the specific circumstances expected to be faced by El Paso and its business units in 2011. The threshold levels represent reasonably achievable goals, whereas the maximum levels represent a significant stretch and would require exceptional performance.

*Annual Incentive Bonus Pool Funding.* After the 2011 financial results became available, El Paso’s Compensation Committee determined the appropriate funding of the 2011 annual incentive bonus pool based on the achievement of the pre-established performance goals for the year, as well as the successful execution of operational and strategic initiatives. 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 Met | | 150%(1) |
| Target Goals Met | | 100%(2) |
| Threshold Goals Met | | 50%(3) |
| Threshold Not Met | | 0% |

(1) The maximum funding of the annual incentive bonus pool is 150% for performance at or above the maximum performance level.

(2) For performance above target but below maximum, actual funding is between 100% and 150%, as determined by El Paso’s Compensation Committee.

(3) For performance above threshold but below target, actual funding is between 50% and 100%, as determined by El Paso’s Compensation Committee.

*Individual Performance Adjustment.* In addition to company performance, individual performance was an important factor in determining annual incentives for 2011. Individual performance goals for 2011 included living El Paso’s core values of stewardship, integrity, safety, accountability, and excellence strengthening El Paso’s balance sheet, continuing to improve our exploration and production cost structure and delivering significant reserve growth with increased oil exposure, increasing our inventory of low-risk, repeatable drilling operations, executing on the construction of El Paso’s backlog of pipeline projects and placing pipeline growth projects in service on time and on budget, continuing to grow El Paso’s master limited partnership, reducing costs, improving execution capability, leadership training and development initiatives and supporting volunteer efforts in the communities in which we work. Based on the executive’s performance in relation to these goals, an individual performance factor is assigned to each executive. The individual performance factor is used to adjust the executive’s actual annual cash incentive award.

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 actual percentage of cash incentive bonuses could be at any level between the minimum and maximum percentages based on company and individual performance.

**Range of Cash Incentive Bonuses as a Percentage of Base Salary for 2011**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | **Minimum Threshold Not Met** | **Threshold** | **Target** | **Maximum** |
| Brent J. Smolik | 0% | 45% | 90% | 202.50% |
| Dane E. Whitehead | 0% | 30% | 60% | 135% |
| Clayton A. Carrell | 0% | 22.5% | 45% | 150% |
| John D. Jensen | 0% | 22.5% | 45% | 150% |
| Marguerite N. Woung‑Chapman | 0% | 17.5% | 35% | 78.75% |

The potential range of values of the annual cash incentive awards for 2011 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.

*El Paso Performance.* In February 2012, El Paso’s Compensation Committee reviewed El Paso’s performance and the performance of its business units relative to the performance goals that were established for the year. In reviewing El Paso’s performance relative to the corporate financial goals, El Paso’s Compensation Committee excluded the impacts of certain items under pre-approved adjustment categories, including: charges due to the deconsolidation of El Paso’s joint venture Ruby Pipeline, L.L.C.; debt extinguishment losses; adjustments to exclude the mark-to-market impact of our derivative positions and include the value of hedge cash settlements; a ceiling test charge related to capitalized costs in Brazil; commodity price fluctuations in the exploration and production business unit, which resulted in an unfavorable adjustment to earnings per share, segment EBITDA and outstanding debt (net of cash); transaction‑related costs; decision to develop El Paso’s exploration and production Eagle Ford shale program without a joint venture partner as well the impact of certain divestitures not contemplated by plan, each of which resulted in adjustments to segment EBITDA; and actions taken to resolve legacy issues. El Paso’s Compensation Committee determined that these items were not related to the ongoing operation of El Paso in a manner consistent with the way the performance goals and ranges were set for compensation‑related purposes. Based on these adjustments, El Paso’s Compensation Committee determined that El Paso achieved the following adjusted results:

• earnings per share of $0.94;

• segment EBITDA of $3,363 million;

• return on total capital of 7.1%; and

• outstanding debt (net of cash) of $12,381 million.

El Paso’s Compensation Committee also considered the strategic initiatives undertaken by El Paso during 2011 that were designed to increase and accelerate stockholder value that required maximum performance on behalf of management and employees, including the proposed spin-off of El Paso’s exploration and production business unit, and the subsequent decision to merge El Paso with Kinder Morgan, Inc. Based on the achievement of the performance goals and after considering management’s execution of strategic initiatives that resulted in acceleration of El Paso’s stockholder value for 2011, El Paso’s Compensation Committee approved a corporate funding level of 150% for cash incentive awards, as well as a funding level of 146% for the exploration and production business unit.

*Individual Performance.* After approving the bonus pool funding levels described above, El Paso’s Compensation Committee and management reviewed the individual performance of each of our named executive officers, with particular focus on individual accountabilities and business unit performance. Based on this review, El Paso’s Compensation Committee, as it related to Messrs. Smolik and Whitehead, and El Paso’s management, as it related to Messrs. Carrell and Jensen and Ms. Woung‑Chapman, awarded the executives above‑target individual performance factors.

*2011 Annual Incentives.* Based on the policies described above, El Paso’s Compensation Committee approved annual incentive bonuses for 2011 performance for Messrs. Smolik and Whitehead, and El Paso management approved annual incentive bonuses for 2011 performance for Messrs. Carrell and Jensen and Ms. Woung‑Chapman in accordance with the funding levels set forth above and the individual performance and contributions of each named executive officer.

**Annual Cash Incentives**

**for 2011 Performance**

|  |  |
| --- | --- |
|  | **Actual Incentive Bonus(1) ($)** |
| Brent J. Smolik | 1,206,900 |
| Dane E. Whitehead | 544,457 |
| Clayton A. Carrell | 344,000 |
| John D. Jensen | 333,750 |
| Marguerite N. Woung‑Chapman | 184,000 |

(1) Cash incentive awards for 2011 performance were paid in March 2012.

**Long-Term Incentive Awards**

El Paso’s annual long-term incentives have historically been comprised of an approximate 50/50 combination of stock options and restricted stock. However, commencing with the April 2011 grant cycle, El Paso’s Compensation Committee incorporated performance shares into the equity program, along with traditional stock options and time-vested restricted stock. The performance shares were designed to pay out on the basis of El Paso’s multi-year relative TSR results, with no dividends payable on unvested performance shares. With 2011 as a transition year, the performance share grant utilized two performance periods, with half of the target grant payout based on El Paso’s TSR results over a two year period (2011-2012), and half on TSR results over a three year period (2011-2013).

The number and kind of El Paso equity awards granted in April 2011 to each of our named executive officers is reflected in the table below.

**Annual Grant of**

**El Paso Long-Term Incentive Awards**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Name** |  | **Stock Options (#)** | **Restricted Stock (#)** | **Performance Shares (#)** |
| Brent J. Smolik | | 108,507 | 66,828 | 48,476 |
| Dane E. Whitehead | | 35,156 | 22,853 | 17,313 |
| Clayton A. Carrell | | 35,156 | 20,776 | 11,668 |
| John D. Jensen | | 35,156 | 20,776 | 11,668 |
| Marguerite N. Woung‑Chapman | | 20,399 | 13,850 | 7,918 |

Stock options were granted at target levels and were not adjusted for company or individual performance. In contrast, restricted stock awards were granted based on the level of achievement during 2011 of certain pre-established performance goals. The performance goals that were used by El Paso’s Compensation Committee for purposes of determining the number of restricted stock awards granted to our named executive officers in April 2011 included (i) El Paso’s 2011 annual corporate financial goals (weighted at 50%) and (ii) El Paso’s 2011 relative TSR compared to its peer group of companies (weighted at 50%). During 2011, El Paso had above‑target achievement of corporate financial goals, together with top quartile TSR performance, which resulted in above‑target restricted share grants to our named executive officers. The performance share grants were granted at target levels, with minor adjustments for individual performance. El Paso made no equity grants to our named executive officers in 2012.

***Impact of EP Energy Sale and El Paso Merger on NEO Compensation***

**Outstanding El Paso Equity Awards**

All of our named executive officers held vested and unvested stock options to purchase shares of El Paso common stock, restricted shares and performance shares granted under El Paso’s equity plan prior to the closing of the sale on May 24, 2012 of El Paso’s exploration and production business unit to EPE Acquisition, LLC. Pursuant to the terms of the merger agreement between El Paso and Kinder Morgan, Inc., which merger became effective on May 25, 2012, each outstanding El Paso stock option, restricted share and performance share automatically vested. In the case of outstanding performance shares, performance was deemed to be attained at target. At such time, 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 Class P common stock of KMI 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. Our named executive officers were deemed to remain in the employ of El Paso up to the effective time of the merger between El Paso and KMI for purposes of the treatment of their outstanding El Paso equity awards, which vested and were converted into merger consideration as described above.

**Retention Plan**

Our named executive officers participate in a retention plan that was established by El Paso in late 2011. The plan was adopted, in consultation with KMI, for full-time employees of El Paso who primarily provided services to El Paso’s exploration and production business (the “Retention Plan”). Based on the level of gross sales proceeds received by El Paso/KMI in respect of the sale of the EP Energy business assets and on the specific time at which such assets were sold, a retention bonus pool in the aggregate amount of $1,750,000 has been established for EP Energy officers. Prior to the determination of actual pool funding in 2012, each of our named executive officers was awarded a percentage interest in the overall pool. In accordance with this allocation, Mr. Smolik’s payment is $226,937, Mr. Whitehead’s payment is $153,564, Mr. Carrell’s payment is $127,085, Mr. Jensen’s payment is $127,085, and Ms. Woung‑Chapman’s payment is $111,762.

**Employment Agreements**

In connection with the closing of the sale of EP Energy to EPE Acquisition, LLC, EP Energy 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 sale. The employment agreements have an initial term that expires on the fifth anniversary of their effective date, but the term of each agreement will automatically be extended 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’s 2004 Key Executive Severance Protection Plan. Additional detail regarding the employment agreements is set forth below.

*Brent J. Smolik.* We 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 our parent 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.* We 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 is 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.* We 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 is 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.* We 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 is also entitled to an additional one-time guaranteed bonus of $600,000 payable in the first quarter of 2013. Mr. Jensen is eligible to participate in all benefit plans and programs that are available to other senior executives of our company. Mr. Jensen’s employment agreement contains provisions related to the payment of benefits upon certain termination events, as well as certain non-compete, non-solicitation and confidentiality restrictions.

*Marguerite N. Woung‑Chapman.* We 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 is 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.

***Executive Compensation Programs at EP Energy***

**Compensation Committee of Our Board of Managers**

The compensation committee of the Board of Managers of our parent, EPE Acquisition, LLC (“Compensation Committee”) is responsible with overseeing and approving compensation for our executive officers.

**Our Compensation Programs**

We believe El Paso’s executive compensation programs were effective at retaining and motivating our named executive officers and in aligning their interests with the interests of El Paso’s stockholders. As described below, the executive compensation programs initially adopted by us are similar to those in place at El Paso immediately prior to the sale, but, in the case of long-term incentive, tailored to reflect our status as a privately‑owned company. The Compensation Committee will continue to evaluate our compensation and benefit programs and may make adjustments as necessary to meet prevailing business needs.

*Compensation Objectives.* Our executive compensation program at EP Energy is 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.

In connection with the closing of the sale and as set forth in the executive officer employment agreements, we adopted the same components of compensation used by El Paso, consisting of base salary, annual performance‑based cash bonus and long-term incentives.

*Base Salary.* The Compensation Committee will review the base salary of each of our named executive officers annually. In making base salary decisions, we anticipate that the Compensation Committee will consider factors including external benchmarking data, scope of job responsibilities, experience and individual performance.

*Annual Performance‑Based Cash Incentive.* In connection with the closing of the sale, we adopted an annual incentive program for our named executive officers similar to the El Paso bonus program described above. The EP Energy officers’ annual cash bonus program will link annual bonus payments to company performance and each individual officer’s performance for the year.

The Compensation Committee will establish company financial and operational performance goals each year as the primary driver in determining annual incentive bonuses for our named executive officers.

In addition to company performance metrics, we anticipate that the Compensation Committee will also consider individual performance in determining annual cash bonus payments.

The Compensation Committee may also consider additional relevant factors, including the marketplace for executive talent within our industry and the competitiveness of our annual cash bonus program relative to our peers.

*Long-Term Incentive Awards.* We provide 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.

*Management Incentive Units.* At the time of the closing of the sale of EP Energy, we issued Management Incentive Units (“MIPs”) to our executive officers, which units are intended to constitute profits interests. The MIPs vest ratably over 5 years based on the executive’s continued employment with the company and become payable based on the achievement of certain predetermined performance measures, including, without limitation, the occurrence of certain liquidity events. The MIPs were issued at no cost and, similar to a stock option, have value only to the extent the value of the company increases. The number of MIPs awarded to each named executive officer is set forth in the table below.

**Management Incentive Units**

**(profits interests)**

|  |  |  |
| --- | --- | --- |
| **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.

*Class A Investment Units.* In addition to the MIPs awards described above, each of our named executive officers purchased Class A units (capital interests) in our parent company (at a purchase price of $1,000 per Class A unit) shortly following the closing of the sale. In connection with this purchase, each named executive officers was awarded a “matching” Class A unit grant in an amount equal to 50% of the Class A units purchased. The matching units are subject to forfeiture in the event of certain termination scenarios. The number of Class A units issued to each named executive officer is set forth in the table below.

**Class A Investment Units**

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

(1) This column reflects the number of Class A units of our parent company that each named executive officer purchased following the closing of the sale of EP Energy to EPE Acquisition, LLC, at a purchase price of $1,000 per Class A unit.

(2) This column reflects the matching Class A unit grant awarded to each named executive officer in connection with his or her buy-in of Class A units.

(3) The management buy-in and matching Class A units were issued on July 23, 2012.

**Post-Employment Benefits**

*401(k) Retirement Plan.* We sponsor a tax-qualified defined contribution retirement plan for a broad‑based group of employees. We make matching contributions (dollar for dollar up to 6% of eligible compensation) and non-elective employer contributions (5% of eligible compensation) to the defined contribution plan, and individual employees, including our named executive officers, are eligible to contribute to the defined contribution plan. We do not sponsor a defined benefit pension plan.

*Severance.* Severance benefits are provided in certain termination events as set forth in the executives’ employment agreements. Benefits include 3 times annual salary and target bonus for the CEO and 2 times annual salary and target bonus for other named executive officers.

*Senior Executive Survivor Benefits Plan.* We sponsor a welfare benefit plan that provides senior executives with survivor benefit coverage in lieu of the coverage provided generally to employees under EP Energy’s group life insurance plan in the event of an executive’s death. The amount of survivor benefit is 21/2 times the executive officer’s annual salary.

*Other Benefits.* We anticipate that our executive officers will be offered limited perquisites, including financial planning assistance.

**Summary Compensation Table**

The following table and the narrative text that follows it provide a summary of the compensation earned or paid to our named executive officers during 2011 according to applicable SEC regulations. All of the information included in this table reflects compensation earned by the individuals for service with El Paso. We were not a reporting company under the Exchange Act for 2009 and 2010. Therefore, pursuant to the executive compensation rules adopted by the SEC, only the compensation of Mr. Smolik is shown for prior years when he was a named executive officer of El Paso. All references in the following tables to stock relate to awards of stock granted by El Paso. The amounts set forth in this table do not necessarily reflect the compensation such persons will receive from EP Energy, which could be higher or lower, because historical compensation was determined by El Paso and going forward compensation levels will be determined based on the compensation policies, programs and procedures established by the compensation committee of our parent, EPE Acquisition, LLC. The principal position listed for each name executive officer below reflects the current position each executive holds at EP Energy.

**Summary Compensation Table**

|  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name and Principal Position** |  | **Year** | **Salary ($)** | **Bonus ($)** | **Stock Awards ($)(1)** | **Option Awards ($)(1)** | **Non-Equity Incentive Plan Compensation ($)(2)** | **Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)(4)** | **All Other Compensation ($)(5)** | **Total ($)** |
| **Brent J. Smolik** | | 2011 | 595,002 | — | 2,563,509 | 795,215 | 1,206,900 | 119,088 | 83,894 | 5,363,608 |
| President & Chief Executive | | 2010 | 576,636 | — | 722,650 | 666,883 | 1,000,000 | 118,356 | 72,049 | 3,156,574 |
| Officer | | 2009 | 566,520 | — | 385,023 | 502,351 | 1,000,000 | 57,136 | 34,724 | 2,545,754 |
| **Dane E. Whitehead** | | 2011 | 402,447 | — | 897,081 | 257,648 | 544,457 | 61,190 | 55,110 | 2,217,933 |
| Executive Vice President & | |  |  |  |  |  |  |  |  |  |
| Chief Financial Officer | |  |  |  |  |  |  |  |  |  |
| **Clayton A. Carrell** | | 2011 | 333,579 | — | 702,422 | 257,648 | 344,000 | 36,849 | 26,821 | 1,701,319 |
| Executive Vice President & | |  |  |  |  |  |  |  |  |  |
| Chief Operating Officer | |  |  |  |  |  |  |  |  |  |
| **John D. Jensen** | | 2011 | 333,591 | — | 702,422 | 257,648 | 333,750 | 37,188 | 27,977 | 1,692,576 |
| Executive Vice President | |  |  |  |  |  |  |  |  |  |
| Operations Services | |  |  |  |  |  |  |  |  |  |
| **Marguerite N. Woung‑Chapman** | | 2011 | 291,114 | — | 472,141 | 149,498 | 184,000 | 46,765 | 40,427 | 1,183,945 |
| Senior Vice President, General | |  |  |  |  |  |  |  |  |  |
| Counsel & Corporate Secretary | |  |  |  |  |  |  |  |  |  |

(1) Amounts in this column reflect the aggregate grant date fair value of stock awards or option awards, as applicable, granted to each named executive officer under El Paso’s equity plan computed in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 718, “*Compensation—Stock Compensation*” (“FASB ASC Topic 718”).

(2) The amount in this column for 2011 reflects each named executive officer’s annual cash incentive bonus earned for 2011 performance under El Paso’s annual incentive plan.

(3) The amount in this column for 2011 reflects the annual change in the actuarial present value of each named executive officer’s accumulated pension benefits under El Paso’s pension and supplemental pension plans. The change in pension value is generally equal to the difference between the actuarial present value at the end of the year and the beginning of the year. The annual change in the actuarial present value of Messrs. Smolik’s, Whitehead’s, Carrell’s and Jensen’s and Ms. Woung‑Chapman’s accumulated pension and supplemental pension benefits for 2011 is $117,938, $60,854, $36,677, $37,032 and $46,333 respectively.

(4) The amount in this column for 2011 also reflects above‑market interest credited to our named executive officers’ El Paso supplemental Retirement Savings Plan account balances under El Paso’s supplemental benefits plan. During 2011, interest was credited to the balance of each executive officer’s supplemental Retirement Savings Plan account balance on a monthly basis at a rate equal to the average of Moody’s Seasoned Aaa Corporate Bond Rate and Moody’s Seasoned Baa Corporate Bond Rate, as published by Moody’s Investors Services, Inc. It was determined that the rate of interest exceeded 120 percent of the applicable federal long-term rate for each month during 2011. The total amount of the above‑market interest credited to Messrs. Smolik’s, Whitehead’s, Carrell’s, and Jensen’s and Ms. Woung‑Chapman’s supplemental Retirement Savings Plan account balance during 2011 was $418, $336, $172, $156, and $432, respectively.

(5) The compensation reflected in the “All Other Compensation” column for 2011 for each of our named executive officers includes company matching contributions to El Paso’s Retirement Savings Plan, supplemental company matching contributions accrued under El Paso’s 2005 Supplemental Benefits Plan, annual executive physicals, financial planning assistance and limited tax reimbursements, which are listed in the table immediately below.

**All Other Compensation included in the Summary Compensation Table for 2011**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Name** |  | **Company Matching Contributions to the Retirement Savings Plan ($)** | **Supplemental Company Matching Contributions under the 2005 Supplemental Benefits Plan ($)(A)** | **Personal Use of Aircraft ($)(B)** | **Annual Executive Physicals ($)(C)** | **Financial Planning ($)(D)** | **Tax Reimbursements ($)(E)** | **Total ($)** |
| Brent J. Smolik | | 11,025 | 60,750 | 11 | 1,397 | 10,082 | 629 | 83,894 |
| Dane E. Whitehead | | 11,025 | 25,085 | — | 2,000 | 17,000 | — | 55,110 |
| Clayton A. Carrell | | 11,025 | 14,399 | — | 1,397 | — | — | 26,821 |
| John D. Jensen | | 11,025 | 14,652 | 209 | 2,000 | — | 91 | 27,977 |
| Marguerite N. Woung‑Chapman | | 22,050 | 16,930 | — | 1,447 | — | — | 40,427 |

(A) The compensation reflected in this column for each of our named executive officers for 2011 includes supplemental company matching contributions which were accrued under El Paso’s 2005 Supplemental Benefits Plan.

(B) The amount shown in this column for Mr. Smolik for 2011 reflects the incremental cost to El Paso for an occasion when his spouse accompanied him on a business‑related flight on private aircraft leased by El Paso. As Mr. Smolik was using the leased aircraft for business purposes, the only incremental cost to El Paso associated with his spouse’s travel was a nominal per person segment fee charged by the private carrier to El Paso, which amount is shown above. The amount shown for Mr. Jensen reflects an occasion when his spouse accompanied him on a business‑related flight using a commercial carrier. When the executive officer’s use of leased aircraft or a guest’s travel does not meet the IRS’s standard for business use, but nevertheless is determined by the company to be business‑related, the cost of that travel is imputed as income to the executive officer and a gross-up payment for taxes is provided. No tax gross-ups are made for flights that are not business‑related. Any tax reimbursements with respect to the imputed income for business‑related travel are reflected in the “Tax Reimbursements” column of this table.

(C) The amounts in this column for 2011 reflect the cost for executive officer annual physicals.

(D) The amounts in this column for 2011 reflect the cost for financial and tax planning assistance. This amount is imputed as income and no tax-gross up is provided.

(E) The amounts in this column for 2011 reflect tax reimbursements associated with imputed income for occasions when the executive’s spouse accompanied him on a business‑related flight.

**Grants of Plan-Based Awards Table**

The following table provides additional information about stock awards and non-equity plan awards granted by El Paso to our named executive officers during the year ended December 31, 2011.

**Grants of Plan-Based Awards**

**During the Year Ended December 31, 2011**

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | |  | **Date of** | **Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(1)** | | | | **Estimated Possible Payouts Under Equity Incentive Plan Awards(2)** | | | **All Other Stock Awards: Number of Shares of** | **All Other Option Awards: Number of Securities** | **Exercise or Base Price** | **Closing Market Price of Underlying Securities** | **Grant Date Fair Value of Stock and** |
| **Name** |  | **Grant Date** | **Compensation Committee Action** | **Threshold Not Met ($)** | **Threshold ($)** | **Target ($)** | **Maximum ($)** | **Threshold (#)** | **Target (#)** | **Maximum (#)** | **Stock or Units (#)(3)** | **Underlying Options (#)(4)** | **of Option Awards ($/Sh)(5))** | **on Grant Date ($/Sh)(6)** | **Option Awards ($)(7)** |
| **Brent J. Smolik** | |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Short-Term Incentive | | N/A | N/A | — | 270,000 | 540,000 | 1,215,000 |  |  |  |  |  |  |  |  |
| Stock Options | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  |  | 108,507 | 18.205 | 18.16 | 795,215 |
| Restricted Stock | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  | 66,828 |  |  |  | 1,216,604 |
| Performance Shares | | 4/1/2011 | 2/7/2011 |  |  |  |  | — | 48,476 | 96,952 |  |  |  |  | 1,346,906 |
| **Dane E. Whitehead** | |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Short-Term Incentive | | N/A | N/A | — | 121,802 | 243,605 | 548,111 |  |  |  |  |  |  |  |  |
| Stock Options | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  |  | 35,156 | 18.205 | 18.16 | 257,648 |
| Restricted Stock | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  | 22,853 |  |  |  | 416,039 |
| Performance Shares | | 4/1/2011 | 2/7/2011 |  |  |  |  | — | 17,313 | 34,626 |  |  |  |  | 481,042 |
| **Clayton A. Carrell** | |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Short-Term Incentive | | N/A | N/A | — | 75,600 | 151,200 | 504,000 |  |  |  |  |  |  |  |  |
| Stock Options | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  |  | 35,156 | 18.205 | 18.16 | 257,648 |
| Restricted Stock | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  | 20,776 |  |  |  | 378,227 |
| Performance Shares | | 4/1/2011 | 2/7/2011 |  |  |  |  | — | 11,668 | 23,336 |  |  |  |  | 324,195 |
| **John D. Jensen** | |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Short-Term Incentive | | N/A | N/A | — | 75,600 | 151,200 | 504,000 |  |  |  |  |  |  |  |  |
| Stock Options | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  |  | 35,156 | 18.205 | 18.16 | 257,648 |
| Restricted Stock | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  | 20,776 |  |  |  | 378,227 |
| Performance Shares | | 4/1/2011 | 2/7/2011 |  |  |  |  | — | 11,668 | 23,336 |  |  |  |  | 324,195 |
| **Marguerite N. Woung‑ Chapman** | |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| Short-Term Incentive | | N/A | N/A | — | 51,710 | 103,421 | 232,697 |  |  |  |  |  |  |  |  |
| Stock Options | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  |  | 20,399 | 18.205 | 18.16 | 149,498 |
| Restricted Stock | | 4/1/2011 | 2/7/2011 |  |  |  |  |  |  |  | 13,850 |  |  |  | 252,139 |
| Performance Shares | | 4/1/2011 | 2/7/2011 |  |  |  |  | — | 7,918 | 15,836 |  |  |  |  | 220,002 |

(1) These columns show the potential value of the payout of the annual cash incentive bonuses for 2011 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 2011 performance is shown in the Summary Compensation Table under the “Non-Equity Incentive Plan Compensation” column.

(2) These columns show the potential payout of performance shares granted in 2011 for each named executive officer if the target and maximum performance levels are achieved. No performance shares were paid out during 2011.

(3) This column shows the number of shares of El Paso restricted stock granted in 2011 to the named executive officers. The shares vest in three equal annual installments beginning one year from the date of grant.

(4) This column shows the number of El Paso stock options granted in 2011 to the named executive officers. The stock options vest in three equal annual installments beginning one year from the date of grant.

(5) This column shows the exercise price for the El Paso stock options granted during 2011, which was the average between the high and low selling prices at which our common stock traded on the date of grant.

(6) This column shows the closing market price of a share of El Paso’s common stock on the date of grant of the stock options.

(7) This column shows the grant date fair value of El Paso restricted stock, performance shares and stock options computed in accordance with FASB ASC Topic 718 granted to the named executive officers during 2011.

The following is a description of material factors necessary to understand the information regarding the stock awards and option awards reflected in the Grants of Plan-Based Awards table. The awards reflected in the Grants of Plan-Based Awards table are shares of El Paso restricted stock, performance shares and non-qualified stock options to purchase shares of El Paso’s common stock which were approved by El Paso’s Compensation Committee and granted to the named executive officers on April 1, 2011. The stock options and restricted stock awards approved granted on April 1, 2011 were made as part of El Paso’s 2011 annual grant of long-term incentive awards based on 2010 performance. The performance share awards granted on April 1, 2011 were not based on 2010 performance, but rather were approved by El Paso’s Compensation Committee and incorporated into El Paso’s long-term incentive program in 2011. As discussed further in the CD&A, the performance shares were designed to payout solely on the basis of El Paso’s multi-year relative TSR results. With 2011 as a transition year, the performance share grant utilized two performance periods, with half of the target grant pay out based on El Paso’s TSR results over a two-year period (2011-2012), and half on TSR results over a three-year period (2011-1013). The grant date fair value of the performance shares granted on April 1, 2011 that vest over a two-year period was $27.93, and the grant date fair value of performance shares that vest over a three-year period was $27.64. The grant date fair value per share for the restricted stock awards granted on April 1, 2011 was $18.205. The grant date fair value per option for the stock options granted on April 1, 2011 was $7.328, computed using a Black‑Scholes option‑pricing model based on several assumptions. These assumptions are based on El Paso’s best estimate at the time of grant and are listed below, as follows:

|  |  |
| --- | --- |
|  | **Grant Date 04/01/2011** |
| Expected Term in Years | 6.0 |
| Expected Volatility | 40% |
| Expected Dividends | 0.5000% |
| Risk-Free Interest Rate | 2.569% |

*Restricted stock carries voting and dividend rights.* The amount of dividends received during 2011 on shares of El Paso’s unvested restricted stock granted to our named executive officers is factored into the grant date fair value per share and is not required to be included in the Summary Compensation Table or Grants of Plan-Based Awards table but is reflected in the table below.

|  |  |  |
| --- | --- | --- |
| **Name** |  | **Dividends Received during 2011 on Restricted Stock ($)** |
| Brent J. Smolik | | 5,427 |
| Dane E. Whitehead | | 2,058 |
| Clayton A. Carrell | | 1,441 |
| John D. Jensen | | 1,475 |
| Marguerite N. Woung‑Chapman | | 1,050 |

**Employment Agreements**

As discussed in the CD&A, we entered into employment agreements with our named executive officers in connection with the closing of the sale of EP Energy to EPE Acquisition, LLC. The employment agreements are effective as of May 24, 2012 and have a five year term. See the heading “Impact of EP Energy Sale and El Paso Merger on NEO Compensation” in the CD&A for a summary of the key terms of the employment agreements.

**Outstanding Equity Awards**

The following table summarizes the equity awards El Paso made to our named executive officers which were outstanding as of December 31, 2011.

**Outstanding Equity Awards**

**at December 31, 2011**

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | | **Option Awards** | | | | **Stock Awards** | | | |
|  | | **Number of Securities Underlying Unexercised Options at Fiscal Year-End (#)** | | **Option Exercise Price** | **Option Expiration** | **Number of Shares or Units of Stock That Have Not Vested** | **Market Value of Shares or Units of Stock That Have Not Vested** | **Number of Unearned Shares, Units or Other Rights That Have Not Vested** | **Market or Payout of Unearned Shares, Units or Other Rights That Have Not Vested** |
| **Name** |  | **Exercisable** | **Unexercisable** | **($)(1)** | **Date** | **(#)** | **($)(2)** | **(#)(3)** | **($)(2)** |
| Brent J. Smolik | | 106,112 | — | 14.580 | 4/02/2017 | 13,053(7) | 346,818 | 48,476(11) | 1,288,007 |
|  | | 108,319 | — | 16.705 | 4/01/2018 | 21,617(8) | 574,364 |  |  |
|  | | 116,063 | 58,032(4) | 6.335 | 4/01/2019 | 43,520(9) | 1,156,326 |  |  |
|  | | 49,020 | 98,039(5) | 11.070 | 4/01/2020 | 66,828(10) | 1,775,620 |  |  |
|  | | — | 108,507(6) | 18.205 | 4/01/2021 |  |  |  |  |
| Dane E. Whitehead | | 30,134 | — | 13.100 | 5/01/2016 | 7,769(7) | 206,422 | 17,313(11) | 460,006 |
|  | | 34,380 | — | 14.580 | 4/02/2017 | 16,352(8) | 434,473 |  |  |
|  | | 35,095 | — | 16.705 | 4/01/2018 | 4,638(9) | 123,232 |  |  |
|  | | 37,605 | 18,802(4) | 6.335 | 4/01/2019 | 22,853(10) | 607,204 |  |  |
|  | | 21,525 | 43,048(5) | 11.070 | 4/01/2020 |  |  |  |  |
|  | | — | 35,156(6) | 18.205 | 4/01/2021 |  |  |  |  |
| Clayton A. Carrell | | 70,323 | — | 13.920 | 3/12/2017 | 3,446(7) | 91,560 | 11,668(11) | 310,019 |
|  | | 9,009 | — | 16.390 | 3/03/2018 | 14,845(9) | 394,432 |  |  |
|  | | 20,364 | — | 16.705 | 4/01/2018 | 20,776(10) | 552,018 |  |  |
|  | | 21,820 | 10,910(4) | 6.335 | 4/01/2019 |  |  |  |  |
|  | | 15,883 | 31,764(5) | 11.070 | 4/01/2020 |  |  |  |  |
|  | | — | 35,156(6) | 18.205 | 4/01/2021 |  |  |  |  |
| John D. Jensen | | — | 10,910(4) | 6.335 | 4/01/2019 | 4,532(7) | 120,415 | 11,668(11) | 310,019 |
|  | | — | 31,764(5) | 11.070 | 4/01/2020 | 14,845(9) | 394,432 |  |  |
|  | | — | 35,156(6) | 18.205 | 4/01/2021 | 20,776(10) | 552,018 |  |  |
| Marguerite N. Woung‑ Chapman | | 6,788 | — | 16.705 | 4/01/2018 | 4,177(7) | 110,983 | 7,918(11) | 210,381 |
|  | | 10,910 | 10,910(4) | 6.335 | 4/01/2019 | 9,348(9) | 248,376 |  |  |
|  | | 9,216 | 18,431(5) | 11.070 | 4/01/2020 | 13,850(10) | 367,995 |  |  |
|  | | — | 20,399(6) | 18.205 | 4/01/2021 |  |  |  |  |

(1) The average between the high and low selling prices at which El Paso’s common stock traded on the grant date is used as the exercise price (or strike price) for stock options. No cash is realized until the shares received upon exercise of an option are sold.

(2) The values represented in this column have been calculated by multiplying $26.57, the closing price of El Paso’s common stock on December 31, 2011 by the number of shares of stock.

(3) The number of shares in this column represents the number of performance shares that would vest based on achieving target‑level performance.

(4) These are stock options that were granted as part of El Paso’s 2009 annual grant of long-term incentive awards and time vest in three equal annual installments beginning one year from the date of grant, with the remaining vesting date on April 1, 2012.

(5) These are stock options that were granted as part of El Paso’s 2010 annual grant of long-term incentive awards and time vest in three equal annual installments beginning one year from the date of grant, with the remaining vesting dates on April 1, 2012 and April 1, 2013.

(6) These are stock options that were granted as part of the El Paso’s 2011 annual grant of long-term incentive awards and time vest in three equal annual installments beginning one year from the date of grant, with vesting dates on April 1, 2012, April 1, 2013 and April 1, 2014.

(7) These are shares of restricted stock that were granted as part of El Paso’s 2009 annual grant of long-term incentive awards and time vest in three equal annual installments beginning one year from the date of grant, with the remaining vesting date on April 1, 2012.

(8) These are shares of restricted stock that El Paso’s Compensation Committee awarded as part of the 2008 performance bonus in lieu of cash and cliff-vest three years from the date of grant, with the vesting date on April 1, 2012.

(9) These are shares of restricted stock that were granted as part of El Paso’s 2010 annual grant of long-term incentive awards and time vest in three equal annual installments beginning one year from the date of grant, with the remaining vesting dates on April 1, 2012 and April 1, 2013.

(10) These are shares of restricted stock that were granted as part of El Paso’s 2011 annual grant of long-term incentive awards and time vest in three equal annual installments beginning one year from the date of grant, with vesting dates on April 1, 2012, April 1, 2013 and April 1, 2014.

(11) These are performance shares granted as part of El Paso’s 2011 annual grant of long-term incentive awards and vest based on El Paso’s multi-year relative TSR results. The amount listed is the target grant. Actual payouts could range between 0-200% of target and would be settled in stock.

**Option Exercises and Stock Vested Table**

The following table sets forth information concerning El Paso stock option exercises and vesting of El Paso restricted stock during 2011 for each of our named executive officers. In satisfaction of applicable SEC regulations, the number of securities for which stock options were exercised (if any) and the aggregate dollar value realized upon the exercise of such stock options is reflected in this table. The number of shares of restricted stock that have vested and the aggregate dollar value realized upon the vesting of such restricted stock is also reflected.

**Option Exercises and Stock Vested**

**During Fiscal Year 2011**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
|  | | **Option Awards** | | **Stock Awards** | |
| **Name** |  | **Number of Shares Acquired on Exercise (#)** | **Value Realized on Exercise ($)** | **Number of Shares Acquired on Vesting (#)** | **Value Realized on Vesting ($)(1)** |
| Brent J. Smolik | | — | — | 48,138 | 876,352 |
| Dane E. Whitehead | | — | — | 22,543 | 410,395 |
| Clayton A. Carrell | | — | — | 15,182 | 276,495 |
| John D. Jensen | | 55,417 | 447,826 | 14,232 | 259,094 |
| Marguerite N. Woung‑Chapman | | 45,536 | 258,331 | 11,607 | 211,305 |

(1) The values represented in this column for El Paso restricted stock have been calculated by multiplying the per share fair market value of the underlying shares on the vesting date by the number of shares of restricted stock that vested.

**Pension Benefits Table**

The following table sets forth information with respect to the pension benefits of each of the named executive officers under El Paso’s qualified and nonqualified pension plans. El Paso sponsors a qualified Pension Plan and supplemental benefits plans in which the named executive officers participate. In satisfaction of applicable SEC regulations, this table provides the number of years of service credited to the named executive officers, the actuarial present value of the named executive officers’ accumulated benefits at the earliest unreduced retirement age and the dollar amount of benefits paid, if any, to a named executive officer under each of the plans during 2011. No pension benefits were paid to the named executive officers during 2011.

**Pension Benefits**

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Name** |  | **Plan Name** | **Number of Years Credited Service (#)** | **Present Value of Accumulated Benefit ($)(1)** | **Payments During Last Fiscal Year ($)** |
| Brent J. Smolik | | Pension Plan | 5 | 79,233 | — |
|  | | Supplemental Benefits Plan | — | — | — |
|  | | 2005 Supplemental Benefits Plan | 5 | 298,632 | — |
| Dane E. Whitehead | | Pension Plan | 6 | 86,557 | — |
|  | | Supplemental Benefits Plan | — | — | — |
|  | | 2005 Supplemental Benefits Plan | 6 | 125,084 | — |
| Clayton A. Carrell | | Pension Plan | 5 | 66,004 | — |
|  | | Supplemental Benefits Plan | — | — | — |
|  | | 2005 Supplemental Benefits Plan | 5 | 59,832 | — |
| John D. Jensen | | Pension Plan | 5 | 65,111 | — |
|  | | Supplemental Benefits Plan | — | — | — |
|  | | 2005 Supplemental Benefits Plan | 5 | 50,527 | — |
| Marguerite N. Woung‑Chapman | | Pension Plan | 15 | 227,581 | — |
|  | | Supplemental Benefits Plan | 8 | 10,985 | — |
|  | | 2005 Supplemental Benefits Plan | 7 | 63,791 | — |

(1) The present value of the named executive officers’ accumulated pension benefits in this column reflects a 4.32 percent discount rate and December 31, 2011 measurement date. The calculations reflect an age 65 commencement date.

The following is a description of material factors necessary to understand the information disclosed above in the Pension Benefits table for each of the named executive officers. El Paso’s Pension Plan provides pension benefits under a cash balance plan formula that defines participants’ accrued benefits in terms of a notional cash account balance. Eligible El Paso employees become participants in the Pension Plan immediately upon employment and are fully vested in their benefits upon the earliest of the completion of three years of service or attainment of age 65. At the end of each calendar quarter, participant cash account balances are increased by an interest credit based on the 5-Year U.S. Treasury constant maturity yield, subject to a minimum interest credit of 4 percent per year, plus a pay credit equal to a percentage of salary and bonus.

Amounts in the Pension Benefits table reported as the actuarial present value of each named executive officer’s accumulated benefits are calculated as of December 31, 2011 using the same assumptions that are used for El Paso’s pension liability disclosure in Note 13 to El Paso’s financial statements included in its 2011 Annual Report on Form 10-K filed with the SEC on February 27, 2012. However, the amounts in the Pension Benefits table assume no pre-retirement decrements (i.e., that the named executive officers work and survive to retirement age) and reflect an age 65 commencement date.

Under El Paso’s qualified Pension Plan and applicable Code provisions, for 2011 compensation in excess of $245,000 could not be taken into account and the maximum payable benefit in 2011 was $195,000. For 2011, any excess benefits otherwise accruing under the Pension Plan were payable under El Paso’s 2005 Supplemental Benefits Plan which was adopted effective January 1, 2005 in connection with the implementation of Section 409A of the Code. The 2005 Supplemental Benefits Plan replaced El Paso’s prior Supplemental Benefits Plan for benefits accruing after 2004. The benefits that accrue under the 2005 Supplemental Benefits Plan are supplemental benefits for officers and key management employees (including all of the named executive officers) who could not be paid under El Paso’s Pension Plan and/or Retirement Savings Plan due to certain Code limitations. The supplemental pension benefits under El Paso’s 2005 Supplemental Benefits Plan, when combined with the supplemental pension benefits the executive is entitled to receive under the prior Supplemental Benefits Plan and the amounts a participant is entitled to receive under El Paso’s qualified Pension Plan, will be the actuarial equivalent of the Pension Plan’s benefit formula had the limitations of the Code not been applied. See the “Nonqualified Deferred Compensation” table below for additional information regarding our named executive officers’ supplemental Retirement Savings Plan benefits. The management committee of the plans designates who may participate and also administers the plan.

**Nonqualified Defined Contribution and Other Nonqualified Deferred Compensation Plans**

The following table sets forth information with respect to nonqualified defined contribution plans sponsored by El Paso for each of the named executive officers as of December 31, 2011. El Paso sponsors a supplemental benefits plan that provides for the crediting of matching contributions that could not be paid under El Paso’s Retirement Savings Plan due to Code limitations. El Paso does not sponsor a traditional nonqualified deferred compensation plan that provides for deferrals of base salary and bonuses for executive officers. None of the named executive officers had withdrawals or distributions of supplemental Retirement Savings Plan benefits during 2011.

**Nonqualified Deferred Compensation**

**as of December 31, 2011**

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| **Name** |  | **Registrant Contributions in Last Fiscal Year ($)(1)** | **Aggregate Earnings in Last Fiscal Year ($)(2)** | **Aggregate Balance at Last Fiscal Year End ($)(3)** |
| Brent J. Smolik | | 60,750 | 5,816 | 182,289 |
| Dane E. Whitehead | | 25,085 | 2,223 | 70,282 |
| Clayton A. Carrell | | 14,399 | 1,141 | 38,405 |
| John D. Jensen | | 14,652 | 1,040 | 36,648 |
| Marguerite N. Woung‑Chapman | | 16,930 | 2,852 | 75,316 |

(1) The amounts in this column are reported as compensation to the named executive officers in the Summary Compensation Table in the “All Other Compensation” column as supplemental company matching contributions for El Paso’s Retirement Savings Plan which were accrued under El Paso’s 2005 Supplemental Benefits Plan. See footnote 5 to the Summary Compensation Table.

(2) Of the amounts in this column, $418 for Mr. Smolik, $336 for Mr. Whitehead, $172 for Mr. Carrell, $156 for Mr. Jensen and $432 for Ms. Woung‑Chapman are reported as compensation in the Summary Compensation Table in the “Change in Pension Value and Nonqualified Deferred Compensation Earnings” column. See footnote 4 to the Summary Compensation Table.

(3) Of the totals in this column, $60,750 for Mr. Smolik, $25,085 for Mr. Whitehead, $14,399 for Mr. Carrell, $14,652 for Mr. Jensen and $16,930 for Ms. Woung‑Chapman, were reported as compensation in the Summary Compensation Table included in this registration statement.

The following is a description of material factors necessary to understand the information disclosed above in the Nonqualified Deferred Compensation table for each of the named executive officers. The registrant’s contributions reflected in this table include supplemental company matching contributions for the Retirement Savings Plan which are accrued under El Paso’s supplemental benefits plans. The supplemental Retirement Savings Plan benefits are excess benefits in the form of company matching contributions that could not be made under El Paso’s Retirement Savings Plan due to Code limitations. During 2011, these excess benefits were credited by El Paso to each executive’s supplemental Retirement Savings Plan account balance under El Paso’s 2005 Supplemental Benefits Plan. The plan administrator determines the rate of interest, if any, periodically attributable to the balance of each supplemental Retirement Savings Plan account. For 2011, interest was credited to the balance of each executive’s supplemental Retirement Savings Plan account balance on a monthly basis at a rate equal to the average of Moody’s Seasoned Aaa Corporate Bond Rate and Moody’s Seasoned Baa Corporate Bond Rate, as published by Moody’s Investors Services, Inc.

**Potential Payments upon Termination or Change in Control**

The following tables reflect the incremental value of compensation and benefits each named executive officer would have received in the event of an involuntary termination without cause, death, disability, termination with cause and a termination following a change in control relative to a voluntary termination of employment by the executive. Pursuant to SEC rules, all amounts below are based upon amounts payable in the event the termination event occurred as of December 31, 2011, and thus reflect amounts payable under El Paso’s compensation programs in effect at that time. All amounts are estimates of the amounts which would have been paid to the executive officers upon their termination. The actual amounts to be paid can only be determined at the time of such executive officer’s termination.

**Potential Payments upon Termination or Change in Control Assuming Termination Event Occurs on December 31, 2011**

*Payments made upon Voluntary Termination*

The following table reflects the total value of payments the named executive officers would have received in the event of a voluntary termination on December 31, 2011. In the event a named executive officer voluntarily terminated his or her employment, the executive officer would have been entitled to his or her vested benefits under El Paso’s Pension Plan and Retirement Savings Plan (including supplemental benefits). Under El Paso’s equity compensation plan, unvested equity awards would be forfeited in the event of a voluntary termination.

**Payments made upon Voluntary Termination**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **Name** |  | **Pension Benefits ($)(1)(2)** | **Supplemental Pension Benefits ($)(2)** | **Retirement Savings Plan Benefits ($)** | **Supplemental Retirement Savings Plan Benefits ($)** | **Equity Awards ($)** | **Total ($)** |
| Brent J. Smolik | | 76,609 | 288,744 | 271,831 | 182,289 | 5,449,195 | 6,268,668 |
| Dane E. Whitehead | | 83,385 | 120,501 | 150,731 | 70,282 | 2,258,908 | 2,683,807 |
| Clayton A. Carrell | | 62,989 | 57,099 | 152,485 | 38,405 | 1,823,489 | 2,134,467 |
| John D. Jensen | | 61,533 | 47,751 | 182,841 | 36,648 | — | 328,773 |
| Marguerite N. Woung-Chapman | | 218,511 | 71,796 | 462,308 | 75,316 | 430,575 | 1,258,506 |
| Total | |  |  |  |  |  | 12,674,221 |

(1) The amounts in this column reflect a lump sum payment.

(2) The amounts in these columns may differ from the amounts in the Pension Benefits table due to several factors, including the use of different assumptions and the timing of commencement of payment.

*Incremental Payments made upon Involuntary Termination without Cause*

The following table reflects the incremental value of enhanced benefits the named executive officers would have received in the event of an involuntary termination without cause as of December 31, 2011 above the compensation and benefits that the executive officer would have been entitled to as a result of a voluntary termination, which includes a severance payment, continued medical benefits and the value of restricted stock that vest on a pro-rata basis. Under El Paso’s severance plan, the amount of severance pay is based on the individual’s years of service and his or her compensation level. The maximum amount of severance pay is 1 times the participant’s annual base salary. Severance pay is paid in a lump sum as soon as administratively practicable following termination. Participants are also entitled to receive continued medical and dental coverage for a period of three months following termination. Under El Paso’s equity compensation plans, restricted stock vests on a pro-rata basis and unvested stock options are forfeited in the event of an involuntary termination without cause.

**Incremental Payments made upon Involuntary Termination without Cause**

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
|  | | **Severance Plan** | | **Equity Awards** | | |  |
| **Name** |  | **Severance Payment ($)** | **Continued Medical Benefits ($)** | **Stock Options ($)(1)** | **Restricted Stock ($)(2)** | **Performance Shares ($)(3)** | **Total ($)** |
| Brent J. Smolik | | 600,000 | 3,369 | — | 1,641,415 | 536,670 | 2,781,454 |
| Dane E. Whitehead | | 406,008 | 3,369 | — | 508,709 | 191,672 | 1,109,758 |
| Clayton A. Carrell | | 336,000 | 3,369 | — | 349,767 | 129,174 | 818,310 |
| John D. Jensen | | 336,000 | 3,369 | — | 371,103 | 129,174 | 839,646 |
| Marguerite N. Woung‑Chapman | | 295,488 | 1,623 | — | 264,743 | 87,659 | 649,513 |
| Total | |  |  |  |  |  | 6,198,681 |

(1) Unvested stock options are forfeited in the event of an involuntary termination without cause.

(2) This column shows the value of shares of El Paso restricted stock that vest on a pro-rata basis in the event of an involuntary termination without cause calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(3) This column shows the value of El Paso performance shares that vest on a pro-rata basis in the event of an involuntary termination without cause based on target level achievement, calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

***Incremental Payments made upon Death***

The following table reflects the incremental value of enhanced benefits our named executive officers would have received in the event of death above the compensation and benefits the executive officers are entitled to as a result of a voluntary termination. El Paso sponsored a Senior Executive Survivor Benefits Plan that provided certain senior executives of El Paso with survivor benefit coverage in lieu of the coverage provided generally under El Paso’s group life insurance plan. The amount of benefits provided is 2.5 times the executive officer’s annual salary. Messrs. Smolik, Whitehead, Carrell and Jensen participated in El Paso’s Senior Executive Survivor Benefits Plan during 2011. Under El Paso’s equity compensation plan, outstanding stock options become fully vested and exercisable and the restriction periods applicable to shares of restricted stock immediately lapse in the event of death.

**Incremental Payments made upon Death**

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | | **Survivor** | **Equity Awards** | | |  |
| **Name** |  | **Benefit Coverage ($)** | **Stock Options ($)(1)** | **Restricted Stock ($)(2)** | **Performance Shares ($)(3)** | **Total ($)** |
| Brent J. Smolik | | 1,500,000 | 3,601,543 | 3,853,128 | 536,670 | 9,491,341 |
| Dane E. Whitehead | | 1,015,000 | 1,341,782 | 1,371,331 | 191,672 | 3,919,785 |
| Clayton A. Carrell | | 840,000 | 1,007,186 | 1,038,010 | 129,174 | 3,014,370 |
| John D. Jensen | | 840,000 | 1,007,186 | 1,066,865 | 129,174 | 3,043,225 |
| Marguerite N. Woung‑Chapman | | 295,000 | 677,082 | 727,354 | 87,659 | 1,787,095 |
| Total | |  |  |  |  | 21,255,816 |

(1) This column shows the value of El Paso stock options that become fully vested and exercisable in the event of the death of a named executive officer calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(2) This column shows the value of shares of El Paso restricted stock that become fully vested in the event of the death of a named executive officer calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(3) This column shows the value of El Paso performance shares that vest on a pro-rata basis in the event of death, calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

*Incremental Payments made upon Disability*

The following table reflects the incremental value of enhanced benefits our named executive officers would have received under El Paso’s welfare benefits plan in the event of permanent disability above the compensation and benefits the executive officers are entitled to as a result of a voluntary termination, which include disability benefits, the value of unvested stock options that become fully vested and the value of restricted stock that vests on a pro-rata basis. In the event of a named executive officer’s permanent disability, disability income would be payable on a monthly basis as long as the executive officer qualifies as permanently disabled. For purposes of this table, we have assumed the executive officer is disabled for a period of one year. The restrictions on outstanding shares of restricted stock lapse on a prorated basis and all stock options become fully vested and exercisable in the event an executive officer becomes permanently disabled. In addition, in the event of disability, performance shares vest on a pro-rata basis based on target.

**Incremental Payments made upon Disability**

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
|  | |  | **Equity Awards** | | |  |
| **Name** |  | **Disability Income ($)(1)** | **Stock Options ($)(2)** | **Restricted Stock ($)(3)** | **Performance Shares ($)(4)** | **Total ($)** |
| Brent J. Smolik | | 300,000 | 3,601,543 | 1,641,415 | 536,670 | 6,079,628 |
| Dane E. Whitehead | | 243,605 | 1,341,782 | 508,709 | 191,672 | 2,285,768 |
| Clayton A. Carrell | | 201,600 | 1,007,186 | 349,767 | 129,174 | 1,687,727 |
| John D. Jensen | | 168,000 | 1,007,186 | 371,103 | 129,174 | 1,675,463 |
| Marguerite N. Woung‑Chapman | | 147,744 | 677,082 | 182,642 | 87,659 | 1,095,127 |
| Total | |  |  |  |  | 12,823,713 |

(1) In the event of a named executive officer’s permanent disability, 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 is paid to the executive officer for a period of one year.

(2) This column shows the value of El Paso stock options that become fully vested and exercisable in the event of the disability of a named executive officer calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(3) This column shows the value of shares of El Paso restricted stock that vest on a pro-rata basis in the event of disability calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(4) This column shows the value of El Paso performance shares that vest on a pro-rata basis in the event of disability, calculated using $26,57, the closing price of El Paso’s common stock on December 31, 2011.

*Incremental Payments made upon Termination with Cause*

In the event a named executive officer is terminated with cause, the named executive officer would not receive any benefits above the compensation and benefits he or she is entitled to as a result of a voluntary termination.

***Incremental Payments made upon a Change in Control of El Paso***

The following table reflects the incremental value of enhanced benefits the named executive officers would have received in the event of termination of employment on December 31, 2011 following a change in control of El Paso above the compensation and benefits the executive officers are entitled to as a result of a voluntary termination, which include benefits under El Paso’s 2004 Key Executive Severance Protection Plan and the value of stock options and restricted stock that become fully vested. The plan provides severance benefits following an involuntary/good reason termination of employment within two years of a change in control of El Paso for certain executives designated by El Paso’s Board or El Paso’s Compensation Committee, including all of our named executive officers, and supersedes benefits payable under El Paso’s severance plan (see “Incremental Payments made upon Involuntary Termination without Cause” above).

**Incremental Payments made upon a Change in Control of El Paso**

|  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | | **2004 Key Executive Severance Protection Plan** | | |  | | |  |
|  | |  |  | **Continued** | **Equity Awards** | | |  |
| **Name** |  | **Severance Payment ($)** | **Bonus Payment ($)** | **Medical Benefits ($)** | **Stock Options ($)(1)** | **Restricted Stock ($)(2)** | **Performance Shares ($)(3)** | **Total ($)** |
| Brent J. Smolik | | 2,280,000 | 540,000 | 27,126 | 3,601,543 | 3,853,128 | 1,288,007 | 11,589,804 |
| Dane E. Whitehead | | 1,299,226 | 243,605 | 27,126 | 1,341,782 | 1,371,331 | 460,006 | 4,743,076 |
| Clayton A. Carrell | | 974,400 | 151,200 | 27,126 | 1,007,186 | 1,038,010 | 310,019 | 3,507,941 |
| John D. Jensen | | 974,400 | 151,200 | 27,126 | 1,007,186 | 1,066,865 | 310,019 | 3,536,796 |
| Marguerite N. Woung‑Chapman | | 398,909 | 103,421 | 7,005 | 677,082 | 727,354 | 210,381 | 2,124,152 |
| Total | |  |  |  |  |  |  | 25,501,769 |

(1) This column shows the value of El Paso stock options that become fully vested and exercisable in the event of a change in control of El Paso calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(2) This column shows the value of shares of El Paso restricted stock that become fully vested in the event of a change in control of El Paso calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

(3) This column shows the value of El Paso performance shares that vest at target in the event of a change in control of El Paso calculated using $26.57, the closing price of El Paso’s common stock on December 31, 2011.

**Director Compensation**

Members of the Board of Managers of our parent, EPE Acquisition, LLC, do not receive a retainer or board meeting fees from EPE Acquisition, LLC for serving on the Board. All members of the Board are reimbursed for their reasonable expenses for attending Board functions.

**SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT**

All of our equity interests are held indirectly by EPE Acquisition, LLC and we do not have any limited liability company units issued and outstanding. The following table sets forth information regarding the beneficial ownership of our equity interests as of September 1, 2012, and shows the percentage owned by:

• each person known to beneficially own more than 5% of our equity interests;

• each of our Named Executive Officers;

• each member of our Board of Managers; and

• all of the executive officers and members of our Board of Managers as a group.

The percentages of our equity interests beneficially owned are reported on the basis of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, 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 otherwise indicated in the footnotes below, each of the beneficial owners has, to our knowledge, sole voting and investment power with respect to the indicated equity interests, and has not pledged any such equity interests as security.

|  |  |  |
| --- | --- | --- |
|  | | **Beneficial Ownership of Equity  Interests** |
| **Name of Beneficial Owner** |  | **Percentage of Ownership** |
| EPE Acquisition, LLC(1) | | 100.0% |
| Brent J. Smolik(2) | | — |
| Dane E. Whitehead(3) | | — |
| Clayton A. Carrell(4) | | — |
| John D. Jensen(5) | | — |
| Marguerite N. Woung‑Chapman(6) | | — |
| Greg Beard(7) | | — |
| Joshua J. Harris(7) | | — |
| Chang-Seok Jeong(8) | | — |
| Pierre F. Lapeyre, Jr.(9) | | — |
| David Leuschen(9) | | — |
| Sam Oh(7) | | — |
| Donald A. Wagner(10) | | — |
| Rakesh Wilson(7) | | — |
| All managers and named executive officers as a group | | — |

\* Indicates less than 1%

(1) All of our equity interests are held by EPE Holdings LLC. EPE Intermediate LLC is the sole member of EPE Holdings LLC, and EPE Acquisition, LLC (“EPE Acquisition”) is the sole member of EPE Intermediate LLC. ANRP (EPE AIV), L.P. (“ANRP EPE”), AIF PB VII (LS AIV), L.P. (“AIF PB”), AIF VII (AIV), L.P. (“AIF VII”), Apollo (EPE Intermediate DC I), LLC (“Intermediate I”) and Apollo (EPE Intermediate DC II), LLC (“Intermediate II,” and together with ANRP EPE, AIF PB, AIF VII and Intermediate I, the “Apollo Funds”) have the right to appoint five out of ten members to EPE Acquisition’s board of managers and may thus be deemed to control actions that EPE Acquisition’s board of managers may take with respect to our equity interests that require approval of a majority of EPE Acquisition’s managers. Apollo Management VII, L.P. (“Management VII”) is the manager of each of ANRP EPE, AIF PB and AIF VII, and a manager of Intermediate I and Intermediate II along with Apollo Commodities Management, L.P. (“Commodities Management”), which also serves as a manager of Intermediate I and Intermediate II. The general partner of Management VII is AIF VII Management, LLC (“AIF VII LLC”) and the general partner of Commodities Management is Apollo Commodities Management GP, LLC (“Commodities GP”). 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 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 Units beneficially owned by EPE Acquisition. The address of EPE Holdings LLC, EPE Intermediate LLC and EPE Acquisition, LLC is c/o EP Energy LLC, 1001 Louisiana Street, Houston, Texas 77002. The address of each of the Apollo Funds other than ANRP EPE is One Manhattanville Road, Suite 201, Purchase, New York 10577. The address of ANRP EPE, Management VII, Commodities Management, AIF VII LLC, Commodities GP, Apollo Management, Management 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) Mr. Smolik holds 6,000 Class A units of EPE Acquisition, LLC, which accounts for less than 1% of the issued and outstanding equity interests of EPE Acquisition, LLC. The address of Mr. Smolik is c/o EP Energy LLC, 1001 Louisiana Street, Houston, Texas 77002.

(3) Mr. Whitehead holds 2,550 Class A units of EPE Acquisition, LLC, which accounts for less than 1% of the issued and outstanding equity interests of EPE Acquisition, LLC. The address of Mr. Whitehead is c/o EP Energy LLC, 1001 Louisiana Street, Houston, Texas 77002.

(4) Mr. Carrell holds 1,800 Class A units of EPE Acquisition, LLC, which accounts for less than 1% of the issued and outstanding equity interests of EPE Acquisition, LLC. The address of Mr. Carrell is c/o EP Energy LLC, 1001 Louisiana Street, Houston, Texas 77002.

(5) Mr. Jensen holds 1,800 Class A units of EPE Acquisition, LLC, which accounts for less than 1% of the issued and outstanding equity interests of EPE Acquisition, LLC. The address of Mr. Jensen is c/o EP Energy LLC, 1001 Louisiana Street, Houston, Texas 77002.

(6) Ms. Woung‑Chapman holds 1,100 Class A units of EPE Acquisition, LLC, which accounts for less than 1% of the issued and outstanding equity interests of EPE Acquisition, LLC. The address of Ms. Woung‑Chapman is c/o EP Energy LLC, 1001 Louisiana Street, Houston, Texas 77002.

(7) The address of each of the managers is c/o Apollo Global Management, LLC, 9 West 57th Street, New York, New York 10019.

(8) The address of the manager is c/o Korea National Oil Corporation, 57 Gwampyeong‑ro212beong-gil, Dongan-gu, Anyang, Gyeonggido, Korea 431-711.

(9) The address of each of the managers is c/o Riverstone Holdings LLC, 712 Fifth Avenue, 19th Floor, New York, New York 10019.

(10) The address of the manager is c/o Access Industries Holdings LLC, 730 Fifth Avenue, 20th Floor, New York, New York 10019.

**CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS**

**Second Amended and Restated Limited Liability Company Agreement of Parent**

In connection with the Acquisition Transactions, certain affiliates of Apollo (collectively, the “Apollo Member”), EPE 892 and TE Co-Investors (DC), LLC (the “EPE 892 Member”), EPE Domestic Co-Investors, L.P. (the “EPE Domestic Member”), EPE Overseas Co-Investors (DC), LLC (the “EPE Overseas Member,” and together with the EPE 892 Member and EPE Domestic Member, the “Co-Investment Members”), an affiliate of Access (the “Access Member”), a vehicle through which management holds class A common units (“Class A Units”) of Parent (the “EMI Member”), an affiliate of KNOC (the “KNOC Member”), Riverstone V Everest Holdings, L.P. (the “Riverstone Member” and, together with the KNOC Member and the Access Member, the “Principal Members”), a vehicle through which management holds class B profits interest units (“Class B Units”) of Parent (the “EEH Member”) (collectively, the “Members”) and Parent, entered into a second amended and restated limited liability company agreement of Parent (the “LLC Agreement”). The Apollo Member, the Co-Investment Members, the Principal Members and the EMI Member were issued Class A Units (such Members in their capacity as holders of Class A Units, the “Class A Members”).

The Board initially consists of nine Managers: (a) four designated by the Apollo Member; (b) two designated by the Riverstone Member; (c) one designated by the Access Member; (d) one designated by the KNOC Member; and (e) the Chief Executive Officer of Parent.

The number of Managers that each such Member is entitled to designate is subject to such Member maintaining a certain Class A Unit ownership threshold. All decisions of the Board require a majority vote of the Managers, other than certain extraordinary specified matters, which require the approval of a majority of the Managers, which majority must include the affirmative vote by a Manager designated by a Principal Member or its replacement elected in accordance with the LLC Agreement.

The LLC Agreement provides for customary rights of first refusal, drag-along rights, tag-along rights and preemptive rights for all Class A Members.

If, by the fifth anniversary of the consummation of the Acquisition Transactions, Parent or a successor entity of Parent has not consummated an initial public offering or a change of control transaction, the Apollo Member or the Class A Members holding 40% of the then outstanding Class A Units shall have the right to cause Parent to consummate a qualified initial public offering (“QIPO”) without the approval of the Board and without the consent of the other Members.

**Related Party Transaction Policy**

Under the LLC Agreement, the consummation of any transaction or series of related transactions involving Parent or any of its subsidiaries, on the one hand, and any Member, Manager or an affiliate of any Member or Manager, on the other hand (each such transaction, a “Related Party Transaction”), requires the approval of a majority of the Managers, other than those Managers that are (or whose affiliates are) party to such Related Party Transaction or that have been designated by the Class A Members that are party, or whose affiliates are party to, such Related Party Transaction. This voting requirement does not apply to (among other things): (i) any transaction consummated in the ordinary course of business, on arm’s length terms and *de minimis* in nature; and (ii) an acquisition of additional securities by a Class A Member pursuant to an exercise of its preemptive rights pursuant to the LLC Agreement.

**Transaction Fee Agreement**

In connection with the Acquisition Transactions, Apollo Global Securities, LLC, the Riverstone Member (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 (“EP Energy Global”) and Parent (the “Transaction Fee Agreement”) relating to the provision of certain structuring, financial, investment banking and other similar advisory services by the Service Providers to Parent, its direct and indirect divisions and subsidiaries, parent entities or controlled affiliates (collectively, the “Company Group”) in connection with the Acquisition Transactions and future transactions. Parent will pay 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 Acquisition Transactions, arranging the financing and performing other services in connection with the Acquisition Transactions. Subject to the terms and conditions of the Transaction Fee Agreement, Parent will pay to the Service Providers an additional transaction fee equal to the lesser of (i) 1% of the aggregate enterprise value paid or provided by the Company Group and (ii) $100,000,000 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 Acquisition Transactions 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 Parent, EP Energy Global or any other member of the Company Group.

**Management Fee Agreement**

In connection with the Acquisition Transactions, Apollo Management VII, L.P., Apollo Commodities Management, L.P., with respect to Series I, the Riverstone Member, Access and KNOC (collectively, the “Management Service Providers”) entered into a management fee agreement with Parent 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 Acquisition Transactions. In exchange for the provision of such services, Parent will pay the Management Service Providers a non-refundable annual management fee of $25 million in the aggregate.

**Participation of Apollo Global Securities, LLC in the Sales of the Initial Notes**

JEV, LLC is an affiliate of Apollo, one of the Sponsors, and acted as an initial purchaser in the sales of the initial notes. Apollo Global Securities, LLC received $937,500, $2,500,000 and $131,250 of the gross spread in the sales of the initial senior secured notes, initial 2020 senior notes and initial 2022 senior notes, respectively.