EP Energy Corp
Form 10-Q
July 30, 2015
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2015
OR
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission File Number 001-36253

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

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

Telephone Number: (713) 997-1000
Internet Website: www.epenergy.com

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark 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 x | Accelerated filer o |
| Non-accelerated filer o<br>(Do not check if a smaller reporting company) | Smaller reporting company o |

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

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

Class A Common Stock, par value $0.01 per share. Shares outstanding as of July 20, 2015: 247,971,026

Class B Common Stock, par value $0.01 per share. Shares outstanding as of July 20, 2015: 803,709

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

| | | |
|---|---|---|
| /d | = | per day |
| Bbl | = | barrel |
| Boe | = | barrel of oil equivalent |
| Gal | = | gallons |
| LLS | = | light Louisiana sweet crude oil |
| MBoe | = | thousand barrels of oil equivalent |
| MBbls | = | thousand barrels |
| Mcf | = | thousand cubic feet |
| MMBtu | = | million British thermal units |
| MMBbls | = | million barrels |
| MMcf | = | million cubic feet |
| MMGal | = | million gallons |
| NGLs | = | natural gas liquids |
| NYMEX | = | New York Mercantile Exchange |
| TBtu | = | trillion British thermal units |
| WTI | = | West Texas intermediate |

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

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

All references to "common stock" herein refer to Class A common stock.

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CAUTIONARY STATEMENTS FOR PURPOSES OF THE “SAFE HARBOR” PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

We have made statements in this document that constitute forward-looking statements, as that term is defined in the Private Securities Litigation Reform Act of 1995. Forward-looking statements include information concerning possible or assumed future results of operations. The words “believe”, “expect”, “estimate”, “anticipate” and similar expressions will generally identify forward-looking statements. These statements may relate to information or assumptions about:

- capital and other expenditures;
- financing plans;
- capital structure;
- liquidity and cash flow;
- pending legal proceedings, claims and governmental proceedings, including environmental matters;
- future economic and operating performance;
- operating income;
- management’s plans; and
- goals and objectives for future operations.

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these variances can be material, depending upon the circumstances. We cannot assure you that the statements of expectation or belief contained in our forward-looking statements will result or be achieved or accomplished. Important factors that could cause actual results to differ materially from estimates or projections contained in our forward-looking statements are described in our 2014 Annual Report on Form 10-K. There have been no material changes to the risk factors described in the Form 10-K.

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PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

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

| | Quarters ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Operating revenues | | | | |
| Oil | $307 | $461 | $536 | $867 |
| Natural gas | 46 | 75 | 94 | 153 |
| NGLs | 15 | 30 | 28 | 57 |
| Financial derivatives | (179) | (290) | 24 | (425) |
| Total operating revenues | 189 | 276 | 682 | 652 |
| Operating expenses | | | | |
| Natural gas purchases | 8 | 5 | 15 | 8 |
| Transportation costs | 25 | 26 | 52 | 49 |
| Lease operating expense | 47 | 50 | 94 | 94 |
| General and administrative | 35 | 42 | 82 | 175 |
| Depreciation, depletion and amortization | 253 | 214 | 477 | 406 |
| Exploration and other expense | 6 | 5 | 12 | 13 |
| Taxes, other than income taxes | 23 | 34 | 45 | 67 |
| Total operating expenses | 397 | 376 | 777 | 812 |
| Operating loss | (208) | (100) | (95) | (160) |
| Loss on extinguishment of debt | (41) | — | (41) | (17) |
| Interest expense | (81) | (80) | (165) | (159) |
| Loss from continuing operations before income taxes | (330) | (180) | (301) | (336) |
| Income tax benefit | (118) | (68) | (108) | (124) |
| Loss from continuing operations | (212) | (112) | (193) | (212) |
| (Loss) income from discontinued operations, net of tax | — | (6) | — | 4 |
| Net loss | $(212) | $(118) | $(193) | $(208) |
| Basic and diluted net (loss) income per common share | | | | |
| Loss from continuing operations | $(0.87) | $(0.46) | $(0.79) | $(0.88) |
| (Loss) income from discontinued operations, net of tax | — | (0.03) | — | 0.01 |
| Net loss | $(0.87) | $(0.49) | $(0.79) | $(0.87) |
| Basic and diluted weighted average common shares outstanding | 244 | 244 | 244 | 240 |

See accompanying notes.

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions)
(Unaudited)

| | June 30, 2015 | December 31, 2014 |
|---|---|---|
| ASSETS | | |
| Current assets | | |
| Cash and cash equivalents | $29 | $22 |
| Accounts receivable | | |
| Customer, net of allowance of less than $1 in 2015 and 2014 | 220 | 234 |
| Other, net of allowance of $1 in 2015 and 2014 | 22 | 38 |
| Income tax receivable | 2 | 24 |
| Materials and supplies | 25 | 25 |
| Derivative instruments | 519 | 752 |
| Prepaid assets | 7 | 7 |
| Total current assets | 824 | 1,102 |
| Property, plant and equipment, at cost | | |
| Oil and natural gas properties | 10,996 | 10,241 |
| Other property, plant and equipment | 79 | 76 |
| | 11,075 | 10,317 |
| Less accumulated depreciation, depletion and amortization | 2,059 | 1,589 |
| Total property, plant and equipment, net | 9,016 | 8,728 |
| Other assets | | |
| Derivative instruments | 160 | 297 |
| Unamortized debt issue costs | 88 | 90 |
| Other | 2 | 2 |
| | 250 | 389 |
| Total assets | $10,090 | $10,219 |

See accompanying notes.

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(In millions)
(Unaudited)

| | June 30, 2015 | December 31, 2014 |
|---|---|---|
| LIABILITIES AND EQUITY | | |
| Current liabilities | | |
| Accounts payable | | |
| Trade | $121 | $142 |
| Other | 302 | 403 |
| Deferred income taxes | 176 | 251 |
| Derivative instruments | 1 | 1 |
| Accrued interest | 49 | 53 |
| Asset retirement obligations | 1 | 2 |
| Other accrued liabilities | 41 | 47 |
| Total current liabilities | 691 | 899 |
| | | |
| Long-term debt | 4,893 | 4,598 |
| Other long-term liabilities | | |
| Deferred income taxes | 293 | 327 |
| Asset retirement obligations | 43 | 40 |
| Other | 6 | 7 |
| Total non-current liabilities | 5,235 | 4,972 |
| | | |
| Commitments and contingencies (Note 8) | | |
| | | |
| Stockholders’ equity | | |
| Class A shares, $0.01 par value; 550 million shares authorized; 248 million shares issued and outstanding at June 30, 2015; 245 million shares issued and outstanding at December 31, 2014 | 2 | 2 |
| Class B shares, $0.01 par value; 0.8 million shares authorized, issued and outstanding at June 30, 2015 and December 31, 2014 | — | — |
| Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding | — | — |
| Additional paid-in capital | 3,519 | 3,510 |
| Retained earnings | 643 | 836 |
| Total stockholders’ equity | 4,164 | 4,348 |
| Total liabilities and equity | $10,090 | $10,219 |

See accompanying notes.

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

| | Six months ended June 30, 2015 | 2014 |
|---|---|---|
| Cash flows from operating activities | | |
| Net loss | $(193) | $(208) |
| Adjustments to reconcile net loss to net cash provided by operating activities | | |
| Depreciation, depletion and amortization | 477 | 414 |
| Impairment charges | — | 15 |
| Deferred income tax benefit | (109) | (136) |
| Loss on extinguishment of debt | 41 | 17 |
| Share-based compensation expense | 9 | 10 |
| Non-cash portion of exploration expense | 7 | 11 |
| Amortization of debt issuance costs | 10 | 11 |
| Other | 1 | — |
| Asset and liability changes | | |
| Accounts receivable | 30 | (21) |
| Accounts payable | (87) | 3 |
| Derivative instruments | 370 | 370 |
| Accrued interest | (4) | (1) |
| Other asset changes | 22 | 6 |
| Other liability changes | (10) | (2) |
| Net cash provided by operating activities | 564 | 489 |
| | | |
| Cash flows from investing activities | | |
| Capital expenditures | (804) | (988) |
| Net proceeds from the sale of assets | — | 150 |
| Cash paid for acquisitions, net of cash acquired | — | (154) |
| Other | 1 | — |
| Net cash used in investing activities | (803) | (992) |
| | | |
| Cash flows from financing activities | | |
| Proceeds from issuance of long-term debt | 1,465 | 1,300 |
| Repayments of long-term debt | (1,199) | (1,440) |
| Proceeds from issuance of stock | — | 669 |
| Debt issuance costs | (19) | — |
| Other | (1) | — |
| Net cash provided by financing activities | 246 | 529 |
| | | |
| Change in cash and cash equivalents | 7 | 26 |
| Cash and cash equivalents | | |
| Beginning of period | 22 | 51 |
| End of period | $29 | $77 |

See accompanying notes

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EP ENERGY CORPORATION
CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(In millions)
(Unaudited)

| | Stockholders' Equity Class A Stock | | Class B Stock | | | | |
|---|---|---|---|---|---|---|---|
| | Shares | Amount | Shares | Amount | Additional Paid-in Capital | Retained Earnings | Total |
| Balance at December 31, 2014 | 245 | $2 | 0.8 | $— | $3,510 | $836 | $4,348 |
| Share-based compensation | 3 | — | — | — | 9 | — | 9 |
| Net loss | — | — | — | — | — | (193) | (193) |
| Balance at June 30, 2015 | 248 | $2 | 0.8 | $— | $3,519 | $643 | $4,164 |

See accompanying notes.

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EP ENERGY CORPORATION
NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC) and in accordance with United States generally accepted accounting principles (U.S. GAAP) as it applies to interim financial statements. Because this is an interim period report presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP and should be read along with our 2014 Annual Report on
Form 10-K. The condensed consolidated financial statements as of June 30, 2015 and 2014 are unaudited. The consolidated balance sheet as of December 31, 2014 has been derived from the audited consolidated balance sheet included in our 2014 Annual Report on Form 10-K. In our opinion, all adjustments which are of a normal, recurring nature are reflected to fairly present these interim period results. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Significant Accounting Policies

There were no changes in significant accounting policies as described in the 2014 Annual Report on Form 10-K.

New Accounting Pronouncements Issued But Not Yet Adopted

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

Debt Issuance Costs. In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2015-03, Simplifying the Presentation of Debt Issuance Costs, which will require us to present unamortized debt issue costs on our balance sheet as a direct deduction from the associated debt liability. Retrospective application of this standard is required beginning in the first quarter of 2016.

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

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2. Acquisitions and Divestitures

Acquisitions. In July 2015, we entered into an agreement to acquire approximately 12,000 net acres adjacent to our Eagle Ford Shale acreage for approximately $118 million, before customary closing adjustments. The transaction is expected to close in September 2015.
Discontinued Operations. In 2014, we reflected as discontinued operations certain non-core assets sold, including domestic natural gas assets in our Arklatex and South Louisiana Wilcox areas and our Brazilian operations. We classified the results of operations of these assets prior to their sale in 2014 as income (loss) from discontinued operations. Summarized operating results of our discontinued operations were as follows:

| | Quarter ended June 30, 2014 | Six months ended June 30, 2014 |
|---|---|---|
| | (in millions) | |
| Operating revenues | $37 | $68 |
| Operating expenses | | |
| Transportation costs | 2 | 5 |
| Lease operating expense | 12 | 25 |
| Depreciation, depletion and amortization | 2 | 8 |
| Impairment charges(1) | 12 | 15 |
| Other expense | 8 | 13 |
| Total operating expenses | 36 | 66 |
| (Loss) gain on sale of assets | (12) | 1 |
| Other income | 2 | 5 |
| (Loss) income from discontinued operations before income taxes | (9) | 8 |
| Income tax (benefit) expense | (3) | 4 |
| (Loss) income from discontinued operations, net of tax | $(6) | $4 |

(1) During the quarter and six months ended June 30, 2014, we recorded $12 million and $15 million in impairment charges related to the sale of our Brazilian operations.

3. Income Taxes

Effective Tax Rate. Interim period income taxes are computed by applying an anticipated annual effective tax rate to year-to-date income or loss, except for significant unusual or infrequently occurring items, which are recorded in the period in which they occur. Changes in tax laws or rates are recorded in the period they are enacted.
For the quarter and six months ended June 30, 2015, our effective tax rates were relatively consistent with the statutory rate. Our effective tax rates in 2015 have been primarily impacted by the effects of state income taxes (net of federal income tax effects). Our effective tax rates for the quarter and six months ended June 30, 2014 differed from the statutory rate as a result of the tax effects of certain transaction costs related to our initial public offering.

4. Earnings Per Share

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on income from continuing operations per common share is antidilutive. Potentially dilutive securities consist of our employee stock options and restricted stock. For the quarter and six months ended June 30, 2015 and 2014, we incurred losses from continuing operations and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive.

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5. Financial Instruments

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

| | June 30, 2015 | | December 31, 2014 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (in millions) | | | |
| Long-term debt | $4,893 | $5,051 | $4,598 | $4,582 |
| Derivative instruments | $678 | $678 | $1,048 | $1,048 |

As of June 30, 2015 and December 31, 2014, the carrying amount of cash and cash equivalents, accounts receivable and accounts payable represent fair value because of the short-term nature of these instruments. We hold long-term debt obligations (see Note 7) with various terms. We estimated the fair value of debt (representing a Level 2 fair value measurement) primarily based on quoted market prices for the same or similar issuances, including consideration of our credit risk related to these instruments.

Oil, Natural Gas and NGLs Derivative Instruments. We attempt to mitigate a portion of our commodity price risk and stabilize cash flows associated with forecasted sales of oil and natural gas through the use of financial derivatives. As of June 30, 2015 and December 31, 2014, we had fixed price derivative contracts for 35 MMBbls and 37 MMBbls of oil and 39 TBtu and 69 TBtu of natural gas, respectively. In addition, we have derivative contracts related to locational basis differences and/or timing of physical settlement prices. As of June 30, 2015, we also had derivative contracts on 38 MMGal of propane. None of these contracts are designated as accounting hedges.

The following table reflects the volumes associated with derivative contracts entered into between July 1, 2015 and July 27, 2015.

| | 2016 Volumes | 2017 Volumes |
|---|---|---|
| Oil (MBbls) | | |
| Basis Swaps | | |
| LLS vs. Brent(1) | — | 1,095 |
| Midland vs. Cushing(2) | 732 | 730 |
| WTI - CM vs. TM(3) | 1,830 | — |

(1) EP Energy receives Brent plus a basis spread and pays LLS.
(2) EP Energy receives Cushing plus a basis spread and pays Midland.
(3) EP Energy receives WTI trade month (TM) and pays WTI calendar month (CM).

Interest Rate Derivative Instruments. We have interest rate swaps with a notional amount of $600 million that extend through April 2017 and are intended to reduce variable interest rate risk. As of June 30, 2015, we had a net liability of less than $1 million and as of December 31, 2014, we had a net asset of $3 million related to interest rate derivative instruments included in our consolidated balance sheets. For the quarters ended June 30, 2015 and 2014, we recorded $1 million and $3 million of interest expense, respectively, related to the change in fair market value and cash settlements of our interest rate derivative instruments. For the six months ended June 30, 2015 and 2014, we recorded $5 million and $4 million of interest expense, respectively, related to the change in fair market value and cash settlements of our interest rate derivative instruments.

Fair Value Measurements. We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value.  As of June 30, 2015 and December 31, 2014, all derivative financial instruments were classified as Level 2. Our assessment of an instrument within a level can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of our financial instruments between other levels.

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Financial Statement Presentation. The following table presents the fair value associated with our derivative financial instruments as of June 30, 2015 and December 31, 2014. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

| | Level 2 Derivative Assets | | | | Derivative Liabilities | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Balance Sheet Location | | | | Balance Sheet Location | |
| | Gross Fair Value | Impact of Netting | Current | Non-current | Gross Fair Value | Impact of Netting | Current | Non-current |
| | (in millions) | | | | (in millions) | | | |
| June 30, 2015 | | | | | | | | |
| Derivative instruments | $696 | $(17) | $519 | $160 | $(18) | $17 | $(1) | $— |
| December 31, 2014 | | | | | | | | |
| Derivative instruments | $1,093 | $(44) | $752 | $297 | $(45) | $44 | $(1) | $— |

For the quarters ended June 30, 2015 and 2014, we recorded derivative losses of $179 million and $290 million, respectively, on our financial oil and natural gas derivative instruments. For the six months ended June 30, 2015 and 2014, we recorded a derivative gain of $24 million and a derivative loss of $425 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statement.

## 6. Property, Plant and Equipment

Oil and Natural Gas Properties. As of June 30, 2015 and December 31, 2014, we had approximately $9.0 billion and $8.7 billion of total property, plant, and equipment, net of accumulated depreciation, depletion and amortization on our balance sheet, substantially all of which related to both proved and unproved oil and natural gas properties. At June 30, 2015 and December 31, 2014, the costs associated with unproved oil and natural gas properties totaled approximately $0.5 billion and $0.7 billion, respectively. During the six months ended June 30, 2015, we transferred approximately $0.2 billion from unproved properties to proved properties. For both of the quarters ended June 30, 2015 and 2014, we recorded $4 million of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. For the six months ended June 30, 2015 and 2014, we recorded $8 million and $11 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of June 30, 2015 or December 31, 2014.

Impairment Assessment. Forward commodity prices can play a significant role in determining future impairments of our proved or unproved property. For the quarters and six months ended June 30, 2015 and 2014, we did not record any impairments of our oil and natural gas properties included in continuing operations. Considering the significant amount of fair value allocated to our oil and natural gas properties pursuant to our acquisition in 2012 by affiliates of Apollo Global Management, LLC (Apollo) and other private equity investors, sustained low oil and natural gas prices and further price reductions or changes to our future capital and development plans due to the lower price environment could result in an impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be material.

Leasehold acquisition costs associated with non-producing areas are assessed for impairment based on our estimated drilling plans and capital expenditures relative to potential lease expirations. Our unproved property costs were approximately $0.5 billion at June 30, 2015, of which approximately $0.4 billion was associated with Wolfcamp and $0.1 billion with Altamont. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by our continuing exploration and development activities. Our allocation of capital to the development of unproved properties may be influenced by changes in commodity prices (e.g. the decline in oil prices beginning in the fourth quarter of 2014), the availability of drilling rigs and associated costs, and/or the relative returns of our unproved property development in comparison to the use of capital for other strategic objectives. Due to the significant decline in oil prices, we have reduced our expected capital expenditures in certain of our operating areas for 2015; however, we currently have the intent and ability to fulfill our drilling commitments prior to the expiration of the associated leases. Should

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oil prices not justify sufficient capital allocation to the continued development of these unproved properties, we could incur impairment charges of our unproved property, and such charges could be material.

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

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate between 7-9 percent and a projected inflation rate of 2.5 percent. The net asset retirement liability as of June 30, 2015 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability from January 1 through June 30, 2015 were as follows:

| | 2015 |
|---|---|
| | (in millions) |
| Net asset retirement liability at January 1 | $42 |
| Liabilities incurred | 2 |
| Liabilities settled | (1) |
| Accretion expense | 1 |
| Net asset retirement liability at June 30 | $44 |

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. Capitalized interest for the quarter and six months ended June 30, 2015 was approximately $5 million and $9 million, respectively. Capitalized interest for the quarter and six months ended June 30, 2014 was approximately $5 million and $10 million, respectively.

7. Long-Term Debt

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

| | Interest Rate | June 30, 2015 | December 31, 2014 |
|---|---|---|---|
| | | (in millions) | |
| $2.75 billion RBL credit facility - due May 24, 2019 | Variable | $1,097 | $852 |
| $750 million senior secured term loan - due May 24, 2018(1)(3) | Variable | 496 | 496 |
| $400 million senior secured term loan - due April 30, 2019(2)(3) | Variable | 150 | 150 |
| $750 million senior secured notes - due May 1, 2019 | 6.875% | — | 750 |
| $2.0 billion senior unsecured notes - due May 1, 2020 | 9.375% | 2,000 | 2,000 |
| $350 million senior unsecured notes - due September 1, 2022 | 7.75% | 350 | 350 |
| $800 million senior unsecured notes - due June 30, 2023 | 6.375% | 800 | — |
| Total | | $4,893 | $4,598 |

(1) The term loan was issued at 99% of par and carries interest at a specified margin over the LIBOR of 2.75%, with a minimum LIBOR floor of 0.75%. As of June 30, 2015 and December 31, 2014, the effective interest rate of the term loan was 3.50%.

(2) The term loan carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of June 30, 2015 and December 31, 2014, the effective rate for the term loan was 4.50%.

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

During the second quarter of 2015, we issued $800 million of 6.375% senior notes due in June 2023. We used a substantial portion of the proceeds from the offering to purchase for cash all of our $750 million senior secured notes due in 2019. In conjunction with repurchasing these notes, we recorded a $41 million loss on extinguishment of debt, of which $12 million was a non-cash expense related to eliminating associated unamortized debt issuance costs. During the first quarter of 2014, we recorded a $17 million non-cash loss on extinguishment of debt upon retiring our senior PIK toggle note with a portion of the proceeds from our initial public offering.

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As of June 30, 2015 and December 31, 2014, we had $88 million and $90 million, respectively, in deferred financing costs on our consolidated balance sheets. During the second quarter ended June 30, 2015, we recorded an additional $19 million in deferred financing costs in conjunction with the issuance of our$800 million senior unsecured notes and with the extension of our Reserve-based Loan facility (RBL Facility). During each of the quarters ended June 30, 2015 and 2014, we amortized $4 million and $6 million, respectively, of deferred financing costs into interest expense. For each of the six months ended June 30, 2015 and 2014, we amortized $10 million and $11 million, respectively, of deferred financing costs into interest expense.

$2.75 Billion Reserve-based Loan. We have a $2.75 billion credit facility in place which allows us to borrow funds or issue letters of credit (LC's). As of June 30, 2015, we had $1.1 billion of outstanding borrowings and approximately $82 million of LC's issued under the facility, leaving $1.6 billion of remaining capacity available.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In April 2015, we completed our semi-annual redetermination, reaffirming the borrowing base at $2.75 billion and extending the maturity date to May 2019, provided that our 2018 and 2019 secured term loans are retired or refinanced six months prior to their maturity. Downward revisions of our oil and natural gas reserves due to future declines in commodity prices, performance revisions, sales of assets or the incurrence of certain types of additional debt, among other items, could cause a redetermination of the borrowing base and could negatively impact our ability to borrow funds under the RBL Facility in the future.

Restrictive Provisions/Covenants. The availability of borrowings under our credit agreements and our ability to incur additional indebtedness is subject to various financial and non-financial covenants and restrictions. There have been no significant changes to our restrictive covenants, and as of June 30, 2015, we were in compliance with all of our debt covenants. For a further discussion of our debt agreements and restrictive covenants, see our 2014 Annual Report on Form 10-K.

## 8. Commitments and Contingencies

### Legal Matters

We and our subsidiaries and affiliates are parties to various legal actions and claims that arise in the ordinary course of our business. For each of these matters, we evaluate the merits of the case or claim, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. While the outcome of our current matters cannot be predicted with certainty and there are still uncertainties related to the costs we may incur, based upon our evaluation and experience to date, we believe we have established appropriate reserves for these matters. It is possible, however, that new information or future developments could require us to reassess our potential exposure related to these matters and adjust our accruals accordingly, and these adjustments could be material. As of June 30, 2015, we had approximately $3 million accrued for all outstanding legal matters.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestitures of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities. For example, the recent decline in commodity prices may create an environment where there is an increased risk that owners and/or operators of assets purchased from us may no longer be able to satisfy plugging and abandonment obligations that attach to such assets. In that event, under various laws or regulations, we may be required to assume these plugging or abandonment obligations on assets no longer owned and operated by us. As of June 30, 2015, we had approximately $8 million accrued related to these indemnifications and other matters.

### Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. Numerous governmental agencies, such as the Environmental Protection Agency (EPA), issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance.

These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate

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

The environmental laws and regulations to which we are subject also require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of June 30, 2015, we had accrued and had exposure of approximately $1 million for related environmental remediation costs associated with onsite, offsite and groundwater technical studies and for related environmental legal costs. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued. Second, where the most likely outcome cannot be estimated, a range of costs is established and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts that we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

Climate Change and Other Emissions. The EPA and several state environmental agencies have adopted regulations to regulate GHG emissions. Although the EPA has adopted a “tailoring” rule to regulate GHG emissions, the U.S. Supreme Court partially invalidated it in an opinion decided June 2014. The tailoring rule remains applicable for those facilities considered major sources of six other “criteria” pollutants and at this time we do not expect a material impact to our existing operations from the rule. There have also been various legislative and regulatory proposals and final rules at the federal and state levels to address emissions from power plants and industrial boilers, which will generally favor the use of natural gas over other fossil fuels such as coal. It remains uncertain what regulations will ultimately be adopted and when they will be adopted. As part of the White House’s Climate Action Plan Strategy to Reduce Methane Emissions, the EPA has announced it will propose additional regulations in 2015 for the oil and gas industry addressing methane and other emissions. Further, the Bureau of Land Management (BLM) is expected to propose additional regulations for public lands in 2015, and the Pipeline and Hazardous Materials Safety Administration is expected to propose new standards in 2015 for natural gas pipelines. Any regulations regarding GHG emissions would likely increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric-driven compression at facilities to obtain regulatory permits and approvals in a timely manner.

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

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

The EPA has promulgated regulations to require pre-construction permits for minor sources of air emissions in tribal lands as of September 2, 2014. On May 22, 2014, the EPA extended this deadline to March 2, 2016, during which time the EPA anticipates separate rulemaking to create general permits for true minor sources in the oil and gas production industry. Until such regulations are adopted, it is uncertain what impact they might have on our operations in tribal lands.

Hydraulic Fracturing Regulations. We use hydraulic fracturing extensively in our operations. Various regulations have been adopted and proposed at the federal, state and local levels to regulate hydraulic fracturing operations. These regulations range from banning or substantially limiting hydraulic fracturing operations, requiring disclosure of the hydraulic fracturing fluids and requiring additional permits for the use, recycling and disposal of water used in such operations. In addition, various agencies, including the EPA 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. Recently, on March 26, 2015, the BLM published final rules for hydraulic fracturing on federal and certain tribal lands, including use of tanks for recovered water, updated cementing and testing requirements, and disclosure of

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chemicals used in hydraulic fracturing. Several states have filed suit to challenge these rules, which a federal court has suspended until mid-September 2015. Although we are reviewing these rules, there is no expected material cost associated with the Company's 2015 program.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) Matters. As part of our environmental remediation projects, we are or have received notice that we could be designated as a Potentially Responsible Party (PRP) with respect to one active site under the CERCLA or state equivalents. As of June 30, 2015, we have estimated our share of the remediation costs at this site to be less than $1 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these matters are included in the reserve for environmental matters discussed above.

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

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

9. Long-Term Incentive Compensation

Our long-term incentive (LTI) programs currently include a cash-based incentive and certain equity-based compensation awards, as further described in our 2014 Annual Report on Form 10-K. A summary of the changes in our non-vested restricted shares for the six months ended June 30, 2015 is presented below:

| | Number of Shares | | Weighted Average Grant Date Fair Value per Share |
|---|---|---|---|
| Non-vested at December 31, 2014 | 1,033,394 | | $ 19.80 |
| Granted | 3,624,672 | | 9.46 |
| Vested | (327,581 | ) | 19.63 |
| Forfeited | (329,962 | ) | 11.93 |
| Non-vested at June 30, 2015 | 4,000,523 | | $ 11.09 |

We record compensation expense on our LTI awards as general and administrative expense over the requisite service period, net of estimates of forfeitures. Pre-tax compensation expense related to all of our LTI awards (both equity-based and cash-based) was approximately $5 million and $10 million during the quarter and six months ended June 30, 2015, respectively, and approximately $8 million and $17 million during the quarter and six months ended June 30, 2014. As of June 30, 2015, we had unrecognized compensation expense of $63 million.  We will recognize an additional $11 million related to outstanding awards as of June 30, 2015 during the remainder of 2015, $36 million over the remaining requisite service periods subsequent to 2015 and $16 million upon a specified capital transaction when the right to such amounts become non-forfeitable.

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10. Related Party Transactions

Affiliate Supply Agreement. For the six months ended June 30, 2015, we have recorded approximately $44 million in capital expenditures for amounts provided under two supply agreements entered into with an Apollo affiliate to provide certain fracturing materials for our Eagle Ford drilling operations.

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

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the financial statements and the accompanying notes presented in Item 1 of Part I of this Quarterly Report on Form 10-Q. 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 our 2014 Annual Report on Form 10-K. Actual results may differ materially from those contained in any forward-looking statements. The quarter and six months ended June 30, 2014 included in these interim financial statements present our Brazil operations and certain domestic natural gas assets sold as discontinued operations. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our", "us" and "the Company" refer to EP Energy Corporation and each of its consolidated subsidiaries.

Our Business

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

- Eagle Ford Shale. The Eagle Ford Shale continues to provide the highest economic returns in our portfolio. We are currently running three rigs in this program.
- Wolfcamp Shale. In our Wolfcamp Shale program, we are focused on optimizing our drilling, completion and artificial lift systems. We are currently running one rig in this program.
- Altamont. In Altamont, we are gaining operational efficiencies as we develop this oil field. Our acreage in this area is largely held-by-production. We are currently running one rig in this program.
- Haynesville Shale. The Haynesville Shale is a natural gas program that currently generates positive cash flow, and our acreage in the Haynesville Shale is held-by-production. We are currently running one rig in this program.

We evaluate growth opportunities that are aligned with our core competencies and that are in areas that we believe can provide a competitive advantage. Strategic acquisitions of leasehold acreage or acquisitions of producing assets can provide us with opportunities to achieve our long-term goals by leveraging existing expertise in each of our operating areas, balancing our exposure to regions, basins and commodities, helping us to achieve risk-adjusted returns competitive with those available within our existing drilling programs and by increasing our reserves.

In July 2015, we entered into an agreement to acquire approximately 12,000 net acres adjacent to our Eagle Ford Shale acreage for approximately $118 million, before customary closing adjustments. The transaction is expected to close in September 2015. The acquisition is estimated to add an average of 500 Bbls/d of oil and 750 Boe/d to our annual estimated 2015 production and 164 future drilling locations. We expect to manage the development capital for the acquired properties within our current 2015 capital guidance.

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

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

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

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

Derivative Instruments. Our realized prices from the sale of our oil and natural gas are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our oil and natural gas, and (ii) other contractual pricing adjustments contained in the underlying sales contract. In order to stabilize cash flows and protect the economic assumptions associated with our capital investment programs, we enter into financial derivative contracts to reduce the financial impact of unfavorable commodity price movements and locational price differences. Certain derivative contracts, usually short term in nature (less than one year), involve the receipt or payment of premiums. No cash premiums were received or paid for the six months ended June 30, 2015. Cash premiums received for the six months ended June 30, 2014, were approximately $1 million.

During the six months ended June 30, 2015, we (i) settled commodity index hedges on approximately 88% of our oil production, 76% of our total liquids production and 91% of our natural gas production at average floor prices of $91.29 per barrel of oil and $4.26 per MMBtu, respectively and (ii) hedged basis risk on approximately 65% of our year-to-date Eagle Ford oil production and a portion of our Wolfcamp remaining production. To the extent our oil and natural gas production is unhedged, either from a commodity index price or locational price perspective, our financial results will be impacted from period to period as further described in Operating Revenues. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of June 30, 2015.

| | 2015 | | 2016 | | 2017 | |
|---|---|---|---|---|---|---|
| | Volumes[(1)] | Average Price[(1)] | Volumes[(1)] | Average Price[(1)] | Volumes[(1)] | Average Price[(1)] |
| Oil | | | | | | |
| Fixed Price Swaps | | | | | | |
| WTI | 9,305 | $89.35 | 8,510 | $80.03 | 4,015 | $66.11 |
| Brent | 1,288 | $100.01 | — | $— | — | $— |
| LLS | — | $— | 9,516 | $80.51 | — | $— |
| Ceilings | 552 | $100.00 | — | $— | — | $— |
| Three Way Collars | | | | | | |
| Ceiling - WTI | — | $— | — | $— | 1,095 | $75.13 |
| Floors - WTI[(2)] | — | $— | — | $— | 1,095 | $65.00 |
| Ceiling - Brent | 552 | $110.02 | — | $— | — | $— |
| Floors - Brent[(3)] | 552 | $100.00 | — | $— | — | $— |
| Basis Swaps | | | | | | |
| LLS vs. WTI[(4)] | 3,128 | $3.93 | 2,013 | $3.91 | — | $— |
| LLS vs. Brent[(5)] | 1,840 | $(3.77 ) | 2,196 | $(4.99 ) | — | $— |
| Midland vs. Cushing[(6)] | 552 | $(0.65 ) | — | $— | — | $— |
| WTI - CM vs. TM[(7)] | 1,840 | $1.28 | 3,660 | $0.20 | — | $— |
| NYMEX Roll[(8)] | 5,520 | $(0.96 ) | 8,230 | $(0.86 ) | — | $— |
| Natural Gas | | | | | | |
| Fixed Price Swaps | 32 | $4.26 | 7 | $4.20 | — | $— |
| Basis Swaps[(9)] | | | | | | |
| CIG | 2 | $(0.25 ) | — | $— | — | $— |

| | | | | | | |
|---|---|---|---|---|---|---|
| Waha | 2 | $(0.07 ) | — | $— | — | $— |
| Propane | | | | | | |
| Fixed Price Swaps | 23 | $0.60 | 15 | $0.55 | — | $— |

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

(2) If market prices settle at or below $55.00 in 2017, we will receive a “locked-in” cash settlement of the market price plus $10.00 per Bbl.

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

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(4) EP Energy receives WTI plus basis spread listed and pays LLS.
(5) EP Energy receives Brent plus basis spread listed and pays LLS.
(6) EP Energy receives Cushing plus basis spread listed and pays Midland.
(7) EP Energy receives WTI trade month (TM) plus the spread listed and pays WTI calendar month (CM).
(8) These positions hedge the timing risk associated with our physical sales. We generally sell oil for the delivery month at a sales price based on the average NYMEX WTI price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").
(9) EP Energy receives the basis spread listed and pays CIG and Waha basis.

The following table reflects the volumes and prices associated with derivative contracts entered into between July 1, 2015 and July 27, 2015, which are not reflected in the table above.

| | 2016 | | 2017 | |
|---|---|---|---|---|
| | Volumes(1) | Average Price(1) | Volumes(1) | Average Price(1) |
| Oil | | | | |
| Basis Swaps | | | | |
| LLS vs. Brent(2) | — | $— | 1,095 | $(3.95) |
| Midland vs. Cushing(3) | 732 | $(0.83) | 730 | $(0.95) |
| WTI - CM vs. TM(4) | 1,830 | $0.10 | — | $— |

(1) Volumes presented are MBbls. Prices presented are per Bbl.
(2) EP Energy receives Brent plus basis spread listed and pays LLS.
(3) EP Energy receives Cushing plus basis spread listed and pays Midland.
(4) EP Energy receives WTI trade month (TM) and pays WTI calendar month (CM).

Summary of Liquidity and Capital Resources. As of June 30, 2015, we had available liquidity, including existing cash, of approximately $1.6 billion. We believe we have sufficient liquidity for 2015 from our cash flows from operations (including our hedging program, which provides significant price protection to our near-term revenues and cash flows), combined with the availability under our $2.75 billion RBL Facility and available cash, to fund our current obligations, projected working capital requirements and capital spending plan. Additionally, with the extension of our $2.75 billion RBL facility maturity date to 2019, the earliest maturity date of our remaining term debt obligations is in 2018. See “Liquidity and Capital Resources” for more information.

Outlook for 2015. For the full year 2015, we expect the following:

- Capital expenditures of approximately $1.2 billion to $1.25 billion, allocated primarily to our oil programs: $800 million to Eagle Ford, $225 million to Wolfcamp, $130 million to Altamont and $70 million to Haynesville.

- Well completions between 165 and 195.

- Average daily production volumes for the year of approximately 102.25 MBoe/d to 110.25 MBoe/d, including average daily oil production volumes of approximately 60.5 MBbls/d to 63.5 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately $10.25 to $11.25 per Boe, and transportation costs of approximately $2.60 to $2.90 per Boe.

- Per unit depreciation, depletion and amortization rate for the year of approximately $24.50 to $26.50 per Boe.

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Production Volumes and Drilling Summary

Production Volumes. Below is an analysis of our production volumes for the six months ended June 30:

| | 2015 | 2014 |
|---|---|---|
| United States (MBoe/d) | | |
| Eagle Ford Shale | 57.6 | 48.5 |
| Wolfcamp Shale | 18.5 | 13.0 |
| Altamont | 17.3 | 14.6 |
| Haynesville Shale | 12.2 | 17.5 |
| Other | 0.1 | 0.2 |
| Total | 105.7 | 93.8 |
| | | |
| Oil (MBbls/d) | 61.7 | 51.0 |
| Natural Gas (MMcf/d) | 186 | 194 |
| NGLs (MBbls/d) | 13.0 | 10.4 |

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes and oil production increased 9.1 MBoe/d (19%) and 7.1 MBbls/d (22%), respectively, for the six months ended June 30, 2015 compared to the six months ended June 30, 2014 due to the success of our drilling program in the area. During the six months ended June 30, 2015, we completed 80 additional operated wells in the Eagle Ford, and we had a total of 476 net operated wells as of June 30, 2015. With a majority of our acreage located in the core of the oil window, primarily in LaSalle county, we continue to grow our oil and NGLs production in the area.

- Wolfcamp Shale—Our Wolfcamp Shale equivalent volumes increased 5.5 MBoe/d (42%) for the six months ended June 30, 2015 compared to the six months ended June 30, 2014 as we continue to progress the development of the program. Wolfcamp produced an average of 9.3 MBbls/d of oil during the six months ended June 30, 2015, and we completed 19 additional operated wells, for a total of 220 net operated wells as of June 30, 2015.

- Altamont—Our Altamont equivalent volumes increased 2.7 MBoe/d (18%) for the six months ended June 30, 2015 compared to the six months ended June 30, 2014. Altamont produced an average of 12.6 MBbls/d of oil during the six months ended June 30, 2015, and we completed 21 additional operated oil wells for a total of 372 net operated wells at June 30, 2015.

- Haynesville Shale—Our Haynesville Shale equivalent volumes decreased 5.3 MMcf/d (30%) for the six months ended June 30, 2015 compared to the six months ended June 30, 2014, due to natural production declines. We have allocated a portion of our capital budget in 2015 to our Haynesville drilling program to test the impact of current completion and refracking techniques on well performance and financial returns. As of June 30, 2015, we had 99 net operated wells in the Haynesville Shale, and our total natural gas production for the six months ended June 30, 2015 was approximately 73 MMcf/d.

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Results of Operations

The information in the table below provides a summary of our generally accepted accounting principles (GAAP) financial results.

| | Quarters ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| | (in millions) | | | |
| Operating revenues | | | | |
| Oil | $307 | $461 | $536 | $867 |
| Natural gas | 46 | 75 | 94 | 153 |
| NGLs | 15 | 30 | 28 | 57 |
| Total physical sales | 368 | 566 | 658 | 1,077 |
| Financial derivatives | (179) | (290) | 24 | (425) |
| Total operating revenues | 189 | 276 | 682 | 652 |
| Operating expenses | | | | |
| Natural gas purchases | 8 | 5 | 15 | 8 |
| Transportation costs | 25 | 26 | 52 | 49 |
| Lease operating expense | 47 | 50 | 94 | 94 |
| General and administrative | 35 | 42 | 82 | 175 |
| Depreciation, depletion and amortization | 253 | 214 | 477 | 406 |
| Exploration and other expense | 6 | 5 | 12 | 13 |
| Taxes, other than income taxes | 23 | 34 | 45 | 67 |
| Total operating expenses | 397 | 376 | 777 | 812 |
| Operating loss | (208) | (100) | (95) | (160) |
| Loss on extinguishment of debt | (41) | — | (41) | (17) |
| Interest expense | (81) | (80) | (165) | (159) |
| Loss from continuing operations before income taxes | (330) | (180) | (301) | (336) |
| Income tax benefit | (118) | (68) | (108) | (124) |
| Loss from continuing operations | (212) | (112) | (193) | (212) |
| (Loss) income from discontinued operations, net of tax | — | (6) | — | 4 |
| Net loss | $(212) | $(118) | $(193) | $(208) |

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters and six months ended June 30, 2015 and 2014. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

| | Quarters ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| | (in millions) | | | |
| Operating revenues: | | | | |
| Oil | $307 | $461 | $536 | $867 |
| Natural gas | 46 | 75 | 94 | 153 |
| NGLs | 15 | 30 | 28 | 57 |
| Total physical sales | 368 | 566 | 658 | 1,077 |
| Financial derivatives | (179) | (290) | 24 | (425) |
| Total operating revenues | $189 | $276 | $682 | $652 |
| Volumes: | | | | |
| Oil (MBbls) | 5,766 | 4,848 | 11,168 | 9,221 |
| Natural gas (MMcf) | 17,037 | 17,429 | 33,665 | 35,128 |
| NGLs (MBbls) | 1,315 | 1,051 | 2,359 | 1,894 |
| Equivalent volumes (MBoe) | 9,920 | 8,804 | 19,138 | 16,970 |
| Total MBoe/d | 109.0 | 96.7 | 105.7 | 93.8 |
| Prices per unit[1]: | | | | |
| Oil | | | | |
| Average realized price on physical sales ($/Bbl)[2] | $53.17 | $95.04 | $47.96 | $93.99 |
| Average realized price, including financial derivatives ($/Bbl)[2][3] | $79.18 | $90.76 | $78.80 | $90.97 |
| Natural gas | | | | |
| Average realized price on physical sales ($/Mcf)[2] | $2.20 | $4.07 | $2.35 | $4.15 |
| Average realized price, including financial derivatives ($/Mcf)[3] | $3.68 | $3.38 | $3.69 | $3.32 |
| NGLs | | | | |
| Average realized price on physical sales ($/Bbl) | $11.91 | $27.93 | $11.96 | $29.87 |
| Average realized price, including financial derivatives ($/Bbl)[3] | $13.08 | $28.46 | $12.72 | $29.77 |

(1) Natural gas prices for the quarter and six months ended June 30, 2015 are calculated including a reduction of $8 million and $15 million, respectively, for natural gas purchases associated with managing our physical sales. Natural gas prices for the quarter and six months ended June 30, 2014 are calculated including a reduction of $5 million and $8 million, respectively, for natural gas purchases associated with managing our physical sales.

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

(3) The quarters ended June 30, 2015 and 2014, include approximately $150 million of cash received and $22 million of cash paid, respectively, for the settlement of crude oil derivative contracts and approximately $25 million of

cash received and $12 million of cash paid, respectively, for the settlement of natural gas financial derivatives. The six months ended June 30, 2015 and 2014, include approximately $344 million of cash received and $29 million of cash paid, respectively, for the settlement of crude oil derivative contracts and approximately $45 million of cash received and $29 million of cash paid, respectively, for the settlement of natural gas financial derivatives. For both the quarter and six months ended June 30, 2015, we received approximately $2 million for the settlement of NGLs derivative contracts. No cash premiums were received or paid for the quarter and six months ended June 30, 2015. Cash premiums received for both the quarter and six months ended June 30, 2014 were approximately $1 million.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter and six months ended June 30, 2015, physical sales decreased by $198 million (35%) and $419 million (39%), respectively, compared to the same periods in 2014. Physical sales have decreased due to lower commodity prices partially offset by oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. The table below displays the price and volume variances on our physical sales when comparing the quarters and six months ended June 30, 2015 and 2014.

| | Quarter ended | | | |
|---|---|---|---|---|
| | Oil | Natural gas | NGLs | Total |
| | (in millions) | | | |
| June 30, 2014 sales | $461 | $75 | $30 | $566 |
| Change due to prices | (242) | (28) | (21) | (291) |
| Change due to volumes | 88 | (1) | 6 | 93 |
| June 30, 2015 sales | $307 | $46 | $15 | $368 |
| | Six months ended | | | |
| | Oil | Natural gas | NGLs | Total |
| | (in millions) | | | |
| June 30, 2014 sales | $867 | $153 | $57 | $1,077 |
| Change due to prices | (514) | (53) | (42) | (609) |
| Change due to volumes | 183 | (6) | 13 | 190 |
| June 30, 2015 sales | $536 | $94 | $28 | $658 |

Oil sales for the quarter and six months ended June 30, 2015 compared to the same periods in 2014 decreased by $154 million (33%) and $331 million (38%), respectively, due primarily to lower oil prices partially offset by oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. For the quarter and six months ended June 30, 2015 compared to the same periods in 2014, Eagle Ford oil production increased by 23% (7.8 MBbls/d) and 22% (7.1 MBbls/d), respectively, Wolfcamp oil production increased by 14% (1.1 MBbls/d) and 24% (1.8 MBbls/d), respectively, and Altamont oil production increased by 10% (1.2 MBbls/d) and 17% (1.8 MBbls/d), respectively.

Natural gas sales decreased for the quarter and six months ended June 30, 2015 compared to the same periods in 2014 primarily due to lower natural gas prices and a decrease in volumes due to natural production declines in the Haynesville Shale, despite natural gas volume growth in Wolfcamp, Eagle Ford and Altamont.

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

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

Quarters ended June 30,

| | 2015 | | 2014 | |
|---|---|---|---|---|
| | Oil (Bbl) | Natural gas (MMBtu) | Oil (Bbl) | Natural gas (MMBtu) |
| Differentials and deducts | $(4.87) | $(0.40) | $(7.83) | $(0.66) |
| NYMEX | $57.94 | $2.64 | $102.99 | $4.67 |

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| | Six months ended June 30, | | | |
|---|---|---|---|---|
| | 2015 | | 2014 | |
| | Oil (Bbl) | Natural gas (MMBtu) | Oil (Bbl) | Natural gas (MMBtu) |
| Differentials and deducts | $(5.51) | $(0.45) | $(6.72) | $(0.62) |
| NYMEX | $53.29 | $2.81 | $100.84 | $4.80 |

The smaller oil differentials and deducts in the quarter and six months ended June 30, 2015 were primarily a result of an increase in LLS relative to NYMEX and improved physical sales contracts with access to new markets in Eagle Ford as well as improved refinery postings and Salt Lake City refinery expansions in Altamont. The smaller gas differentials and deducts in the quarter and six months ended June 30, 2015 were primarily a result of improved locational basis differentials in the Haynesville area and lower excess royalties paid on flared gas.

NGLs sales decreased for the quarter and six months ended June 30, 2015 compared to the same periods in 2014. Average realized prices declined in 2015 compared to the same period in 2014, due in part to lower pricing on all liquids components. NGLs volume increased as a result of our Eagle Ford and Wolfcamp drilling programs. For the quarter and six months ended June 30, 2015 compared to the same periods in 2014, Eagle Ford NGLs volumes increased by 18% (1.2 MBbls/d) and 16% (1.2 MBbls/d), respectively, and Wolfcamp NGLs volumes increased by 71% (1.7 MBbls/d) and 54% (1.5 MBbls/d), respectively.

As of June 30, 2015, the NYMEX spot price of a barrel of oil was $59.47 versus the NYMEX spot price of a MMBtu of natural gas of $2.83, or a ratio of 21 to 1. Despite declines in oil prices, the value difference between these commodities is such that we will continue to target increases in our oil volumes in our capital budget. Growth in our overall oil sales (including the impact of financial derivatives) will largely be impacted by our ability to grow these volumes and will also be impacted by commodity pricing to the extent we are unhedged and by the location of our production and the nature of our sales contracts. Based on our hedges in place as of June 30, 2015, we are approximately 97% hedged (based on the midpoint of our 2015 production guidance) at a weighted average price of $91.11 per barrel for the remainder of 2015. See "Our Business" for further information on our derivative instruments.
Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the quarter ended June 30, 2015, we recorded $179 million of derivative losses compared to derivative losses of $290 million during the quarter ended June 30, 2014. For the six months ended June 30, 2015, we recorded $24 million of derivative gains compared to derivative losses of $425 million during the six months ended June 30, 2014.
Operating Expenses

Transportation costs. Transportation costs for the quarter and six months ended June 30, 2015 were $25 million and $52 million, respectively, compared to $26 million and $49 million for the same periods in 2014. Total transportation costs remained relatively flat for the quarter ended June 30, 2015 and have increased slightly for the six months ended June 30, 2015 primarily due to oil transportation costs associated with Eagle Ford and Wolfcamp as a result of our production growth and new contracts in these areas.

Lease operating expense. Lease operating expense for the quarter and six months ended June 30, 2015 were $47 million and $94 million, respectively, compared to $50 million and $94 million for the same periods in 2014. For the quarter and six months ended June 30, 2015, we incurred a decrease in lease operating expense in Eagle Ford of approximately $2 million and $7 million, respectively, due to lower chemical costs due to changing the method (amine unit vs. chemicals) in which we treated our gas and lower power costs due to releasing rental generators. These decreases were partially offset by higher disposal, maintenance and repair costs in Wolfcamp associated with growing production volumes in this area of approximately $4 million and $7 million, respectively, for the quarter and six months ended June 30, 2015.

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General and administrative expenses. General and administrative expenses for the quarter and six months ended June 30, 2015 were $35 million and $82 million, respectively, compared to $42 million and $175 million for the same periods in 2014. The overall decrease of $7 million and $93 million for the quarter and six months ended June 30, 2015 was due to lower payroll, benefits and administrative costs of $8 million and $14 million compared to the same periods in 2014 from lower headcount and lower Sponsor related fees. In the first quarter of 2014 we paid advisory fees of $6.25 million and a transaction fee of $83 million to the Sponsors under a Management Fee Agreement upon completion of our initial public offering. These agreements terminated with the completion of our 2014 initial public offering. Partially offsetting these items were transition and restructuring costs of $8 million recorded during the first quarter of 2015.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the quarter and six months ended June 30, 2015 were $253 million and $477 million, respectively, compared to $214 million and $406 million for the same periods in 2014. Our depreciation, depletion and amortization costs increased in 2015 compared to the same periods in 2014 due to an increase in production volumes from the ongoing development of higher cost oil programs (e.g., Eagle Ford and Wolfcamp) and slightly higher depletion rates. We expect our depletion rate will continue to increase compared to our current levels as a result of this ongoing development of our higher cost oil programs. Our average depreciation, depletion and amortization costs per unit for the quarters and six months ended June 30 were:

| | Quarters ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Depreciation, depletion and amortization ($/Boe)[1] | $25.46 | $24.31 | $24.90 | $23.90 |

Exploration and other expense. For the quarter and six months ended June 30, 2015, we recorded $6 million and $12 million of exploration expense compared to $5 million and $13 million for the same periods in 2014. Included in exploration expense for the quarter and six months ended June 30, 2015 are $4 million and $8 million, respectively, of amortization of unproved leasehold costs compared to $4 million and $11 million for the same periods in 2014. In addition, in the six months ended June 30, 2015, we recorded approximately $2 million as other expense in conjunction with the early termination of a contract for drilling rigs during the first quarter of 2015.

Taxes, other than income taxes. Taxes, other than income taxes for the quarter and six months ended June 30, 2015 were $23 million and $45 million, respectively, compared to $34 million and $67 million for the same periods in 2014. Production taxes decreased in 2015 compared to the same periods in 2014 due to lower commodity prices which have a significant impact on severance taxes.

Cash Operating Costs and Adjusted Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas. Cash operating costs is a non-GAAP measure calculated on a per Boe basis and includes total operating expenses less depreciation, depletion and amortization expense, transportation costs, exploration expense, natural gas purchases and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition, restructuring and other non-recurring costs, management and other fees paid to the Sponsors (which terminated on January 23, 2014), and the non-cash portion of compensation expense (which represents compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans). We believe cash operating costs and adjusted cash operating costs per unit are valuable measures of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses for the quarters and six months ended June 30:

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| | Quarters ended June 30, | | | |
|---|---|---|---|---|
| | 2015 | | 2014 | |
| | Total | Per Unit[1] | Total | Per Unit[1] |
| | (in millions, except per unit costs) | | | |
| Total continuing operating expenses | $397 | $39.96 | $376 | $42.68 |
| Depreciation, depletion and amortization | (253) | (25.46) | (214) | (24.31) |
| Transportation costs | (25) | (2.56) | (26) | (2.93) |
| Exploration expense[2] | (5) | (0.59) | (5) | (0.53) |
| Natural gas purchases | (8) | (0.78) | (5) | (0.49) |
| Total continuing cash operating costs | 106 | 10.57 | 126 | 14.42 |
| Transition/restructuring costs, non-cash portion of compensation expense and other[3] | 1 | 0.17 | 5 | 0.46 |
| Total adjusted cash operating costs and adjusted per-unit cash operating costs | $107 | $10.74 | $131 | $14.88 |
| Total equivalent volumes (MBoe) | 9,920 | | 8,804 | |

| | Six months ended June 30, | | | |
|---|---|---|---|---|
| | 2015 | | 2014 | |
| | Total | Per Unit[1] | Total | Per Unit[1] |
| | (in millions, except per unit costs) | | | |
| Total continuing operating expenses | $777 | $40.59 | $812 | $47.83 |
| Depreciation, depletion and amortization | (477) | (24.90) | (406) | (23.90) |
| Transportation costs | (52) | (2.73) | (49) | (2.89) |
| Exploration expense[2] | (10) | (0.55) | (13) | (0.75) |
| Natural gas purchases | (15) | (0.75) | (8) | (0.46) |
| Total continuing cash operating costs | 223 | 11.66 | 336 | 19.83 |
| Transition/restructuring costs, non-cash portion of compensation expense and other[3] | (11) | (0.58) | (95) | (5.62) |
| Total adjusted cash operating costs and adjusted per-unit cash operating costs | $212 | $11.08 | $241 | $14.21 |
| Total equivalent volumes (MBoe) | 19,138 | | 16,970 | |

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

(2) Represents exploration expense only.

(3) For the quarter ended June 30, 2015, amount includes approximately $2 million of non-cash compensation expense, adjusted for cash payments made of approximately $7 million. For the six months ended June 30, 2015, amount includes approximately $8 million of transition and severance costs related to restructuring and $3 million of non-cash compensation expense. For the quarter ended June 30, 2014, amount includes $7 million of non-cash compensation expense, adjusted for cash payments made of approximately $12 million. For the six months ended June 30, 2014, amount includes $90 million of transaction, management and other fees paid to the Sponsors, $4 million of non-cash compensation expense and $1 million of transition and severance costs related to restructuring. The non-cash portion of compensation expense represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans.

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

| | Quarters ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| Average cash operating costs ($/Boe) | | | | |
| Lease operating expenses | $4.72 | $5.69 | $4.91 | $5.56 |
| Production taxes[1] | 2.05 | 3.61 | 2.09 | 3.66 |
| General and administrative expenses[2] | 3.56 | 4.86 | 4.30 | 10.34 |
| Taxes, other than production and income taxes | 0.24 | 0.26 | 0.26 | 0.27 |
| Other expenses[3] | — | — | 0.10 | — |
| Total continuing cash operating costs | 10.57 | 14.42 | 11.66 | 19.83 |
| Transition/restructuring costs, non-cash portion of compensation expense and other[2] | 0.17 | 0.46 | (0.58) | (5.62) |
| Total adjusted cash operating costs | $10.74 | $14.88 | $11.08 | $14.21 |

(1) Production taxes include ad valorem and severance taxes which decreased during the quarter and six months ended June 30, 2015 due primarily to lower commodity prices.

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

(3) Includes early rig termination fees of $2 million incurred during the first quarter of 2015.

Other Income Statement Items.

Loss on extinguishment of debt. For the quarter and six months ended June 30, 2015, we recorded $41 million ($12 million of which was non-cash) in losses on extinguishment of debt in conjunction with the early repayment and retirement of our $750 million senior secured notes due 2019. For the six months ended June 30, 2014, we recorded $17 million in losses on extinguishment of debt for the portion of deferred financing costs written off in conjunction with the repayment and retirement of the PIK toggle note.

Interest expense. Interest expense increased for the quarter ended June 30, 2015 compared to the same period in 2014 due to higher interest expense related to our RBL Facility and changes in the fair market value of our interest rate derivative instruments. Interest expense increased for the six months ended June 30, 2015 compared to the same period in 2014 due to higher interest expense related to our RBL Facility partially offset by a decrease due to the retirement of the PIK toggle note.

(Loss) income from discontinued operations. Our (loss) income from discontinued operations for the quarter and six months ended June 30, 2014 includes the financial results of assets classified as discontinued operations and gains (losses) recorded on the sale of these non-core assets in 2014.

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Supplemental Non-GAAP Measures

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

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

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

| | Quarters ended June 30, | | Six months ended June 30, | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| | (in millions) | | | |
| Net loss | $(212) | $(118) | $(193) | $(208) |
| Loss (income) from discontinued operations, net of tax | — | 6 | — | (4) |
| Loss from continuing operations | (212) | (112) | (193) | (212) |
| Income tax benefit | (118) | (68) | (108) | (124) |
| Interest expense, net of capitalized interest | 81 | 80 | 165 | 159 |
| Depreciation, depletion and amortization | 253 | 214 | 477 | 406 |
| Exploration expense(1) | 5 | 5 | 10 | 13 |
| EBITDAX | 9 | 119 | 351 | 242 |
| Mark-to-market on financial derivatives(2) | 179 | 290 | (24) | 425 |
| Cash settlements and premiums on financial derivatives(3) | 177 | (32) | 391 | (57) |
| Non-cash portion of compensation expense(4) | (2) | (5) | 3 | 4 |
| Transition, restructuring and other costs(5) | — | — | 8 | 1 |
| Fees paid to Sponsors(6) | — | — | — | 90 |
| Loss on extinguishment of debt(7) | 41 | — | 41 | 17 |
| Adjusted EBITDAX | $404 | $372 | $770 | $722 |

(1) Represents exploration expense only.

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

(3) Represents actual cash settlements received/(paid) related to financial derivatives, including cash premiums. No cash premiums were received or paid for the quarter and six months ended June 30, 2015. For both the quarter and six months ended June 30, 2014, we received approximately $1 million of cash premiums.

(4) For both the quarter and six months ended June 30, 2015, cash payments were approximately $7 million. For both the quarter and six months ended June 30, 2014, cash payments were approximately $12 million.

(5) Reflects transition and severance costs related to restructuring activities.

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

(7) Represents the loss on extinguishment of debt recorded related to the repayment in May 2015 of our 2019 $750 million senior secured note and the retirement of the PIK toggle note in 2014.

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Commitments and Contingencies

For a further discussion of our commitments and contingencies, see Part I, Item 1, Financial Statements, Note 8.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our RBL Facility. Our primary uses of cash are capital expenditures, debt service requirements including interest, and working capital requirements. As of June 30, 2015, our available liquidity was approximately $1.6 billion. In April 2015, we completed our semi-annual redetermination of our RBL Facility, reaffirming the borrowing base at $2.75 billion and extending the maturity date from May 2017 to May 2019, provided that our 2018 and 2019 secured term loans are retired or refinanced six months prior to their maturity. During the second quarter of 2015, we issued $800 million of senior notes due in June 2023. We used a substantial portion of the proceeds from the offering to purchase for cash all of the $750 million of senior secured notes due 2019.

We believe we have sufficient liquidity from (i) our cash flows from operations (including our significant multi-year hedge program), (ii) availability under the RBL Facility and (iii) available cash, to fund our capital program, current obligations and projected working capital requirements in 2015 and the foreseeable future. Additionally, with the extension of our $2.75 billion RBL Facility maturity date to 2019, the earliest maturity date of our remaining term debt obligations is in 2018. Furthermore, despite the declines in oil prices, we believe our oil and natural gas derivative contracts provide significant commodity price protection on a substantial portion of our anticipated production for 2015 and 2016. These derivative contracts which are primarily fixed price swaps, have been effective in minimizing the impact of price declines to our near-term revenues and also provide greater cash flow certainty. Based on our hedges in place as of June 30, 2015, we are approximately 97% hedged (based on the midpoint of our 2015 production guidance) at a weighted average price of $91.11 per barrel for the remainder of 2015. See "Our Business" for further information on our derivative instruments.

Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the RBL Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all on the occurrence of certain events, such as a change of control, or (iii) obtain additional capital if required on acceptable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. We could be required to take additional future actions if necessary to address further changes in the financial or commodity markets.

Capital Expenditures. For the full year 2015, we expect our capital budget will be approximately $1.2 billion to $1.25 billion. We expect to spend a significant portion of our 2015 capital budget in our oil programs. However, we have also allocated a portion of our capital to our Haynesville Shale natural gas assets. Our capital expenditures and average drilling rigs by area for the six months ended June 30, 2015 were:

| | Capital Expenditures (in millions) | Average Drilling Rigs |
|---|---|---|
| Eagle Ford Shale | $501 | 4.2 |
| Wolfcamp Shale | 149 | 1.1 |
| Altamont | 93 | 1.9 |
| Haynesville Shale | 30 | 0.5 |
| Total | $773 | 7.7 |

Long-Term Debt. As of June 30, 2015, our long-term debt is approximately $4.9 billion, comprised of $3.2 billion in senior notes due in 2020, 2022 and 2023, $646 million in senior secured term loans with maturity dates in 2018 and

2019, and $1.1 billion outstanding under the RBL Facility expiring in 2019. We continually monitor the debt capital markets and our capital structure and will make changes to our capital structure from time to time, with the goal of maintaining flexibility and cost efficiency. For additional details on our long-term debt, including restrictive covenants under our debt agreements, see Part I, Item 1, Financial Statements, Note 7.

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

| | Six months ended June 30, 2015 | 2014 |
|---|---|---|
| Cash Flow from Operations | | |
| Operating activities | | |
| Net loss | $(193) | $(208) |
| Impairment charges | — | 15 |
| Other income adjustments | 436 | 327 |
| Changes in assets and liabilities | 321 | 355 |
| Total cash flow from operations | $564 | $489 |
| | | |
| Other Cash Inflows | | |
| Investing activities | | |
| Net proceeds from the sale of assets | $— | $150 |
| Other | 1 | — |
| | $1 | $150 |
| | | |
| Financing activities | | |
| Proceeds from issuance of long-term debt | 1,465 | 1,300 |
| Proceeds from issuance of stock | — | 669 |
| | 1,465 | 1,969 |
| Total cash inflows | $1,466 | $2,119 |
| | | |
| Cash Outflows | | |
| Investing activities | | |
| Capital expenditures | $804 | $988 |
| Cash paid for acquisitions, net of cash acquired | — | 154 |
| | $804 | $1,142 |
| Financing activities | | |
| Repayments of long-term debt | 1,199 | 1,440 |
| Debt issuance costs | 19 | — |
| Other | 1 | — |
| | 1,219 | 1,440 |
| Total cash outflows | $2,023 | $2,582 |
| | | |
| Net change in cash and cash equivalents | $7 | $26 |

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Item 3. Qualitative and Quantitative Disclosures About Market Risk

This information updates, and should be read in conjunction with the information disclosed in our 2014 Annual Report on Form 10-K, in addition to the information presented in Items 1 and 2 of Part I of this Quarterly Report on Form 10-Q. There have been no material changes in our quantitative and qualitative disclosures about market risks from those reported in our 2014 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at June 30, 2015:

| | | Oil, Natural Gas and NGL Derivatives | | | |
|---|---|---|---|---|---|
| | | 10 Percent Increase | | 10 Percent Decrease | |
| | Fair Value | Fair Value | Change | Fair Value | Change |
| | (in millions) | | | | |
| Price impact[1] | $678 | $459 | $(219) | $897 | $219 |

| | | Oil, Natural Gas and NGL Derivatives | | | |
|---|---|---|---|---|---|
| | | 1 Percent Increase | | 1 Percent Decrease | |
| | Fair Value | Fair Value | Change | Fair Value | Change |
| | (in millions) | | | | |
| Discount rate[2] | $678 | $674 | $(4) | $683 | $5 |
| Credit rate[3] | $678 | $672 | $(6) | $682 | $4 |

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

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

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of June 30, 2015, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Securities Exchange Act of 1934, as amended (Exchange Act), is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of June 30, 2015.

Changes in Internal Control over Financial Reporting

There were no changes in EP Energy Corporation’s internal control over financial reporting during the first six months of 2015 that materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

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## PART II — OTHER INFORMATION

### Item 1. Legal Proceedings

See Part I, Item 1, Financial Statements, Note 8.

### Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in the 2014 Annual Report on Form 10-K.

### Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

### Item 3. Defaults Upon Senior Securities

None.

### Item 4. Mine Safety Disclosures

Not applicable.

### Item 5. Other Information

None.

### Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

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

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

Accordingly, these representations and warranties may not describe the actual state of affairs as of the date they were made or at any other time.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

| | |
|---|---|
| | EP ENERGY CORPORATION |
| Date: July 30, 2015 | /s/ Dane E. Whitehead<br>Dane E. Whitehead<br>Executive Vice President and Chief Financial Officer<br>(Principal Financial Officer) |
| Date: July 30, 2015 | /s/ Francis C. Olmsted III<br>Francis C. Olmsted III<br>Vice President and Controller<br>(Principal Accounting Officer) |

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EP ENERGY CORPORATION
EXHIBIT INDEX

Each exhibit identified below is filed as part of this Report. Exhibits filed with this Report are designated by "*". All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

| Exhibit Number | Description |
|---|---|
| 4.1 | Indenture, dated as of May 28, 2015, between EP Energy LLC and Everest Acquisition Finance Inc., as Co-Issuers, and Wilmington Trust, National Association, as Trustee, in respect of 6.375% Senior Notes due 2023 (Exhibit 4.3 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015). |
| 4.2 | Registration Rights Agreement, dated as of May 28, 2015, between EP Energy LLC, Everest Acquisition<br>Finance Inc. and RBC Capital Markets, LLC, as representative of the several initial purchasers, in respect of 6.375% Senior Notes due 2023. (Exhibit 4.5 to EP Energy LLC's Registration Statement on Form S-4, filed with the SEC on June 24, 2015). |
| *12.1 | Ratio of Earnings to Fixed Charges |
| *31.1 | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *31.2 | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *32.1 | Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| *32.2 | Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| *101.INS | XBRL Instance Document. |
| *101.SCH | XBRL Schema Document. |
| *101.CAL | XBRL Calculation Linkbase Document. |
| *101.DEF | XBRL Definition Linkbase Document. |
| *101.LAB | XBRL Labels Linkbase Document. |
| *101.PRE | XBRL Presentation Linkbase Document. |