EP Energy Corp
Form 10-Q
April 30, 2015
Table of Contents

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 March 31, 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 (State or Other Jurisdiction of Incorporation or Organization)	46-3472728 (I.R.S. Employer Identification No.)
1001 Louisiana Street Houston, Texas (Address of Principal Executive Offices)	77002 (Zip Code)

Telephone Number: (713) 997-1200
Internet Website: www.epenergy.com

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 (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 April 20, 2015: 248,031,390

Class B Common Stock, par value $0.01 per share. Shares outstanding as of April 20, 2015: 811,976

Table of Contents

EP ENERGY CORPORATION

TABLE OF CONTENTS

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
CBM	=	coal bed methane
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
MMcfe	=	million cubic feet of natural gas equivalents
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.

Table of Contents

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.

Table of Contents

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 March 31, 2015	2014
Operating revenues		
Oil	$229	$406
Natural gas	48	78
NGLs	13	27
Financial derivatives	203	(135)
Total operating revenues	493	376
Operating expenses		
Natural gas purchases	7	3
Transportation costs	27	23
Lease operating expense	47	44
General and administrative	47	133
Depreciation, depletion and amortization	224	192
Exploration and other expense	6	8
Taxes, other than income taxes	22	33
Total operating expenses	380	436
Operating income (loss)	113	(60)
Loss on extinguishment of debt	—	(17)
Interest expense	(84)	(79)
Income (loss) from continuing operations before income taxes	29	(156)
Income tax expense (benefit)	10	(56)
Income (loss) from continuing operations	19	(100)
Income from discontinued operations, net of tax	—	10
Net income (loss)	$19	$(90)
Basic and diluted net income (loss) per common share		
Income (loss) from continuing operations	$0.08	$(0.42)
Income from discontinued operations, net of tax	—	0.04
Net income (loss)	$0.08	$(0.38)
Basic and diluted weighted average common shares outstanding	244	238

See accompanying notes.

Table of Contents

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

	March 31, 2015	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$9	$22
Accounts receivable		
Customer, net of allowance of less than $1 in 2015 and 2014	206	234
Other, net of allowance of $1 in 2015 and 2014	28	38
Income tax receivable	2	24
Materials and supplies	24	25
Derivative instruments	746	752
Prepaid assets	7	7
Total current assets	1,022	1,102
Property, plant and equipment, at cost		
Oil and natural gas properties	10,645	10,241
Other property, plant and equipment	79	76
	10,724	10,317
Less accumulated depreciation, depletion and amortization	1,809	1,589
Total property, plant and equipment, net	8,915	8,728
Other assets		
Derivative instruments	289	297
Unamortized debt issue costs	85	90
Other	2	2
	376	389
Total assets	$10,313	$10,219

See accompanying notes.

Table of Contents

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

	March 31, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$106	$142
Other	328	403
Deferred income taxes	250	251
Derivative instruments	1	1
Accrued interest	106	53
Asset retirement obligations	2	2
Other accrued liabilities	35	47
Total current liabilities	828	899
Long-term debt	4,726	4,598
Other long-term liabilities		
Deferred income taxes	339	327
Asset retirement obligations	41	40
Other	7	7
Total non-current liabilities	5,113	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 March 31, 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 March 31, 2015 and December 31, 2014	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Additional paid-in capital	3,515	3,510
Retained earnings	855	836
Total stockholders' equity	4,372	4,348
Total liabilities and equity	$10,313	$10,219

See accompanying notes.

Table of Contents

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

	Quarters ended March 31, 2015	2014
Cash flows from operating activities		
Net income (loss)	$19	$(90)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation, depletion and amortization	224	198
Gain on sale of assets	—	(13)
Deferred income tax expense (benefit)	10	(51)
Loss on extinguishment of debt	—	17
Share-based compensation expense	5	4
Non-cash portion of exploration expense	4	7
Amortization of debt issuance costs	5	5
Other	(1)	3
Asset and liability changes		
Accounts receivable	38	(16)
Accounts payable	(90)	6
Derivative instruments	14	111
Accrued interest	53	53
Other asset changes	23	4
Other liability changes	(13)	(15)
Net cash provided by operating activities	291	223
Cash flows from investing activities		
Capital expenditures	(432)	(459)
Proceeds from the sale of assets	—	17
Net cash used in investing activities	(432)	(442)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	364	550
Repayments of long-term debt	(236)	(964)
Proceeds from issuance of stock	—	669
Net cash provided by financing activities	128	255
Change in cash and cash equivalents	(13)	36
Cash and cash equivalents		
Beginning of period	22	51
End of period	$9	$87

See accompanying notes

Table of Contents

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	—	—	—	5	—	5
Net income	—	—	—	—	—	19	19
Balance at March 31, 2015	248	$2	0.8	$—	$3,515	$855	$4,372

See accompanying notes.

Table of Contents

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 March 31, 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. Our financial statements for prior periods include reclassifications that were made to conform to the current period presentation, none of which impacted our reported net income or stockholders' equity. 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. Retrospective application of this standard is required beginning in the first quarter of 2017. In April 2015, the FASB proposed a deferral of the new revenue standard by one year, with the option of early adoption in 2017. We are currently evaluating the impact, if any, that this update will have on our financial statements.

Table of Contents

2. Acquisitions and Divestitures

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 have 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 March 31, 2014 (in millions)
Operating revenues	$31
Operating expenses	
Transportation costs	3
Lease operating expense	13
Depreciation, depletion and amortization	6
Impairment charges[1]	3
Other expense	5
Total operating expenses	30
Gain on sale of assets	13
Other income	3
Income from discontinued operations before income taxes	17
Income tax expense	7
Income from discontinued operations, net of tax	$10

(1) During the quarter ended March 31, 2014, we recorded $3 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 quarters ended March 31, 2015 and 2014, our effective tax rates were relatively consistent with the statutory rate. Our effective tax rates are primarily impacted by the effects of state income taxes (net of federal income tax effects) and non-deductible compensation expense. Our 2014 effective tax rate also reflects the tax effects of discrete adjustments for 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 which did not affect diluted earnings per share for the quarter ended March 31, 2015.

Table of Contents

5. Financial Instruments

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

	March 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt	$4,726	$4,809	$4,598	$4,582
Derivative instruments	$1,034	$1,034	$1,048	$1,048

As of March 31, 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 March 31, 2015 and December 31, 2014, we had fixed price derivative contracts for 36 MMBbls and 37 MMBbls of oil and 54 TBtu and 69 TBtu of natural gas, respectively. In addition, we also have derivative contracts related to locational basis differences and/or timing of physical settlement prices. As of March 31, 2015, we also had derivative contracts on 35 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 April 1, 2015 and April 24, 2015.

	2015 Volumes	2016 Volumes
Oil (MBbls)		
Fixed Price Swaps		
LLS(1)	—	4,392
Basis Swaps		
WTI - CM vs. TM(2)	—	3,660
NYMEX Roll(3)	490	182

(1) In April 2015, we unwound 1,464 MBbls of 2016 LLS three way collars in exchange for 4,392 MBbls of 2016 LLS fixed price swaps. No cash or other consideration was included as part of this exchange.

(2) EP Energy receives WTI trade month (TM) and pays WTI calendar month (CM).

(3) Hedges 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").

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 March 31, 2015, we have 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 March 31, 2015 and 2014, we recorded $4 million and $1 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 March 31, 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.

Table of Contents

Financial Statement Presentation. The following table presents the fair value associated with our derivative financial instruments as of March 31, 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)			
March 31, 2015								
Derivative instruments	$1,069	$(34)	$746	$289	$(35)	$34	$(1)	$—
December 31, 2014								
Derivative instruments	$1,093	$(44)	$752	$297	$(45)	$44	$(1)	$—

For the quarters ended March 31, 2015 and 2014, we recorded a derivative gain of $203 million and a derivative loss of $135 million, respectively, on our financial oil and natural gas derivative instruments. 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 March 31, 2015 and December 31, 2014, we had approximately $8.9 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 March 31, 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 first quarter of 2015, we transferred approximately $0.2 billion from unproved properties to proved properties. For the quarters ended March 31, 2015 and 2014, we recorded $4 million and $7 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of March 31, 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. Due to the continued decline in oil prices in the first quarter of 2015, we reviewed our proved and unproved property for impairment. For the quarters ended March 31, 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 lower 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 March 31, 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 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.

Table of Contents

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

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate between 7-9 percent and a projected inflation rate of 2.5 percent. The net asset retirement liability as of March 31, 2015 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability from January 1 through March 31, 2015 were as follows:

	2015
	(in millions)
Net asset retirement liability at January 1	$42
Liabilities incurred	1
Liabilities settled	(1)
Accretion expense	1
Net asset retirement liability at March 31	$43

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. Capitalized interest for the quarters ended March 31, 2015 and 2014 was approximately $4 million and $5 million, respectively.

7. Long-Term Debt

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

	Interest Rate	March 31, 2015	December 31, 2014
		(in millions)	
$2.75 billion RBL credit facility - due May 24, 2019	Variable	$980	$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[(3)]	6.875%	750	750
$2.0 billion senior unsecured notes - due May 1, 2020	9.375%	2,000	2,000
$350 million senior unsecured notes - due September 1, 2022	7.75%	350	350
Total		$4,726	$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 March 31, 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 March 31, 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.

As of March 31, 2015 and December 31, 2014, we had $85 million and $90 million, respectively, in deferred financing costs on our consolidated balance sheets. During each of the quarters ended March 31, 2015 and 2014, we amortized $5 million of deferred financing costs in interest expense.

During the first quarter of 2014, we repaid and retired our senior PIK toggle note with a portion of the proceeds from our initial public offering, recording a $17 million loss on extinguishment of debt.

$2.75 Billion Reserve-based Loan (RBL). We have a $2.75 billion credit facility in place which allows us to borrow funds or issue letters of credit (LC's). As of March 31, 2015, we had $980 million of outstanding borrowings and approximately $82 million of LC's issued under the facility, leaving $1.7 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 the 2018 and 2019 secured term loans and senior notes are retired or refinanced six months prior to 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.

Table of Contents

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 March 31, 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 March 31, 2015, we had approximately $2 million accrued for all outstanding legal matters.

Southeast Louisiana Flood Protection Authority v. EP Energy Management, L.L.C. On July 24, 2013, the levee authority for New Orleans and surrounds (The Authority) filed suit against 97 oil, gas and pipeline companies, seeking (among other relief) restoration of wetlands allegedly lost due to historic industry operations in those areas. On February 13, 2015, the District Court dismissed the case for failure to state a claim, finding that the defendants had no duty to the Authority. The Authority has appealed to the U.S. Court of Appeals for the Fifth Circuit. Based on our current analysis of factors surrounding this claim, we believe our exposure to this claim, if any, will not be material to our financial statements.

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 March 31, 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. 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 March 31, 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 Environmental Protection Agency (EPA) and several state environmental agencies have adopted regulations to regulate GHG emissions. Although the EPA has adopted a “tailoring” rule to regulate GHG emissions, the U.S. Supreme Court partially invalidated it in an opinion decided June 2014. The tailoring rule remains applicable for those facilities considered major sources of six other “criteria” pollutants and at this time we do not expect a material impact to our existing operations from the rule. There have also been various legislative and regulatory proposals and final rules at the federal and state levels to address emissions from power plants and industrial boilers, which will generally favor the use of natural gas over other fossil fuels such as coal. It remains uncertain what regulations or amended final rules will ultimately be adopted and when they will be adopted. As part of the White House’s Climate Action Plan Strategy to Reduce Methane Emissions, the EPA has announced it will propose additional regulations in 2015, and the Pipeline and

Table of Contents

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 Bureau of Land Management (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 chemicals used in hydraulic fracturing. Although we are reviewing these amendments, 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 March 31, 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.

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.

Table of Contents

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 quarter ended March 31, 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	3,538,385	9.38
Vested	(2,564)	19.82
Forfeited	(7,223)	16.21
Non-vested at March 31, 2015	4,561,992	$ 11.72

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 $9 million during the quarters ended March 31, 2015 and 2014, respectively. As of March 31, 2015, we had unrecognized compensation expense of $69 million. We will recognize an additional $17 million related to outstanding awards as of March 31, 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.

10. Related Party Transactions

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.

Affiliate Supply Agreement. For the quarter ended March 31, 2015, we have recorded approximately $7 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.

Table of Contents

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 ended March 31, 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 two rigs in this program.
- Haynesville Shale. The Haynesville Shale 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.

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

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

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

To the extent possible, we attempt to mitigate certain of these risks through actions such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to stabilize cash flows and reduce the financial impact of downward commodity price movements on commodity sales. In addition, because we apply mark-to-market accounting, our reported results of operations 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.

Table of Contents

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 quarter ended March 31, 2015. Cash premiums received for the quarter ended March 31, 2014, were less than $1 million.

During the quarter ended March 31, 2015, we (i) settled commodity index hedges on approximately 91% of our oil production, 78% of our total liquids production and 92% of our natural gas production at average floor prices of $91.28 per barrel of oil and $4.26 per MMBtu, respectively and (ii) hedged basis risk on approximately 50% of our year-to-date Eagle Ford oil production. To the extent our oil and natural gas production is unhedged, either from a commodity index price or locational price perspective, our financial results will be impacted from period to period as further described in Operating Revenues. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of March 31, 2015.

	2015		2016		2017	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil						
Fixed Price Swaps						
WTI	13,361	$89.34	8,510	$80.03	4,015	$66.11
Brent	1,925	$100.01	—	$—	—	$—
LLS	—	$—	5,124	$91.88	—	$—
Ceilings	825	$100.00	—	$—	—	$—
Three Way Collars						
Ceiling - Brent	825	$110.02	—	$—	—	$—
Floors - Brent(2)	825	$100.00	—	$—	—	$—
Ceiling - LLS	—	$—	1,464	$99.29	—	$—
Floors - LLS(3)	—	$—	1,464	$94.00	—	$—
Basis Swaps						
LLS vs. WTI(4)	5,163	$4.11	2,013	$3.91	—	$—
LLS vs. Brent(5)	2,750	$(3.77)	2,196	$(4.99)	—	$—
Midland vs. Cushing(6)	825	$(0.65)	—	$—	—	$—
WTI - CM vs. TM(7)	2,750	$1.28	—	$—	—	$—
NYMEX Roll(8)	7,400	$(0.96)	7,316	$(0.92)	—	$—
Natural Gas						
Fixed Price Swaps	47	$4.26	7	$4.20	—	$—
Basis Swaps(9)						
CIG	3	$(0.25)	—	$—	—	$—
Waha	3	$(0.07)	—	$—	—	$—
Propane						
Fixed Price Swaps	35	$0.60	—	$—	—	$—

(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 $85.00 in 2015, we will receive a “locked-in” cash settlement of the market price plus $15.00 per Bbl.

(3) If market prices settle at or below $80.00 in 2016, we will receive a “locked-in” cash settlement of the market price plus $14.00 per Bbl.
(4) EP Energy receives WTI plus basis spread listed and pays LLS.
(5) EP Energy receives Brent plus basis spread listed and pays LLS.
(6) EP Energy receives Cushing plus basis spread listed and pays Midland.
(7) EP Energy receives WTI trade month (TM) plus the spread listed and pays WTI calendar month (CM).
(8) Hedges 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.

Table of Contents

The following table reflects the volumes and prices associated with derivative contracts entered into between April 1, 2015 and April 24, 2015, which are not reflected in the table above.

	2015		2016	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil				
Fixed Price Swaps				
LLS(2)	—	$—	4,392	$67.25
Basis Swaps				
WTI - CM vs. TM	—	$—	3,660	$0.20
NYMEX Roll	490	$(1.00)	182	$(1.00)

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

(2) In April 2015, we unwound 1,464 MBbls of 2016 LLS three way collars in exchange for 4,392 MBbls of 2016 LLS fixed price swaps. No cash or other consideration was included as part of this exchange.

Summary of Liquidity and Capital Resources. As of March 31, 2015, we had available liquidity, including existing cash, of approximately $1.7 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: $825 million to Eagle Ford, $190 million to Wolfcamp, $140 million to Altamont and $100 million to Haynesville.

- Well completions between 160 and 190.

- Average daily production volumes for the year of approximately 97.0 MBoe/d to 107.0 MBoe/d, including average daily oil production volumes of approximately 57 MBbls/d to 63 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately $10.50 to $12.00 per Boe, and transportation costs of $2.95 to $3.15 per Boe.

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

Table of Contents

Production Volumes and Drilling Summary

Production Volumes. Below is an analysis of our production volumes for the quarters ended March 31:

	2015	2014
United States (MBoe/d)		
Eagle Ford Shale	54.7	46.5
Wolfcamp Shale	17.9	11.9
Altamont	17.1	13.4
Haynesville Shale	12.6	18.7
Other	0.1	0.2
Total	102.4	90.7
Oil (MBbls/d)	60.0	48.6
Natural Gas (MMcf/d)	185	197
NGLs (MBbls/d)	11.6	9.3

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes and oil production increased 8.2 MBoe/d (18%) and 6.4 MBbls/d (20%), respectively, for the quarter ended March 31, 2015 compared to the same period in 2014 due to the success of our drilling program in the area. During the quarter ended March 31, 2015, we completed 38 additional operated wells in the Eagle Ford, and we had a total of 439 net operated wells as of March 31, 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 6.0 MBoe/d (50%) for the quarter ended March 31, 2015 compared to the same period in 2014 as we continue to progress the development of the program. During the quarter ended March 31, 2015, we completed 10 additional operated wells, for a total of 214 net operated wells as of March 31, 2015.

- Altamont—Our Altamont equivalent volumes increased 3.7 MBoe/d (28%) for the quarter ended March 31, 2015 compared to the same period in 2014. Altamont produced an average of 12.5 MBbls/d of oil during the quarter ended March 31, 2015, and we completed 9 additional operated oil wells for a total of 368 net operated wells at March 31, 2015.

- Haynesville Shale—Our Haynesville Shale equivalent volumes decreased 36 MMcf/d (32%) for the quarter ended March 31, 2015 compared to the same period in 2014, due to natural production declines. We have allocated a portion of our capital budget in 2015 to our Haynesville drilling program based on its returns in the forecasted commodity price environment. As of March 31, 2015, we had 99 net operated wells in the Haynesville Shale, and our total natural gas production for the first quarter of 2015 was approximately 76 MMcf/d.

Table of Contents

Results of Operations

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

	Quarters ended March 31,	
	2015	2014
	(in millions)	
Operating revenues		
Oil	$229	$406
Natural gas	48	78
NGLs	13	27
Total physical sales	290	511
Financial derivatives	203	(135)
Total operating revenues	493	376
Operating expenses		
Natural gas purchases	7	3
Transportation costs	27	23
Lease operating expense	47	44
General and administrative	47	133
Depreciation, depletion and amortization	224	192
Exploration and other expense	6	8
Taxes, other than income taxes	22	33
Total operating expenses	380	436
Operating income (loss)	113	(60)
Loss on extinguishment of debt	—	(17)
Interest expense	(84)	(79)
Income (loss) from continuing operations before income taxes	29	(156)
Income tax expense (benefit)	10	(56)
Income (loss) from continuing operations	19	(100)
Income from discontinued operations, net of tax	—	10
Net income (loss)	$19	$(90)

Table of Contents

Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters ended March 31, 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 March 31,	
	2015	2014
	(in millions)	
Operating revenues:		
Oil	$229	$406
Natural gas	48	78
NGLs	13	27
Total physical sales	290	511
Financial derivatives	203	(135)
Total operating revenues	$493	$376
Volumes:		
Oil (MBbls)	5,402	4,373
Natural gas (MMcf)	16,628	17,699
NGLs (MBbls)	1,044	843
Equivalent volumes (MBoe)	9,218	8,166
Total MBoe/d	102.4	90.7
Consolidated prices per unit(1):		
Oil		
Average realized price on physical sales ($/Bbl)(2)	$42.40	$92.83
Average realized price, including financial derivatives ($/Bbl)(2)(3)	$78.39	$91.20
Natural gas		
Average realized price on physical sales ($/Mcf)(2)	$2.51	$4.21
Average realized price, including financial derivatives ($/Mcf)(3)	$3.69	$3.26
NGLs		
Average realized price on physical sales ($/Bbl)	$12.04	$32.29
Average realized price, including financial derivatives ($/Bbl)(3)	$12.26	$31.40

(1) Natural gas prices for the quarters ended March 31, 2015 and 2014 are calculated including a reduction of $7 million and $3 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 March 31, 2015 and 2014, include approximately $194 million of cash received and $7 million of cash paid, respectively, for the settlement of crude oil derivative contracts and approximately $20 million of cash received and $17 million of cash paid, respectively, for the settlement of natural gas financial derivatives. The quarters ended March 31, 2015 and 2014, include less than $1 million and approximately $1 million, respectively, of cash paid for the settlement of NGLs derivative contracts. No cash premiums were received for the quarter ended March 31, 2015. Cash premiums received for the quarter ended March 31, 2014 were less than $1 million.

Table of Contents

Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter ended March 31, 2015, physical sales decreased by $221 million (43%) compared to the same period 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 ended March 31, 2015 and 2014.

	Oil	Natural gas	NGLs	Total
	(in millions)			
March 31, 2014 sales	$406	$78	$27	$511
Change due to prices	(272)	(25)	(21)	(318)
Change due to volumes	95	(5)	7	97
March 31, 2015 sales	$229	$48	$13	$290

Oil sales for the quarter ended March 31, 2015 compared to the same period in 2014 decreased by $177 million (44%) due primarily to lower oil prices partially offset by oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. For the quarter ended March 31, 2015 compared to the same period in 2014, Eagle Ford oil production increased by 20% (6.4 MBbls/d), Wolfcamp oil production increased by 32% (2.3 MBbls/d), and Altamont oil production increased by 28% (2.7 MBbls/d).

Natural gas sales decreased for the quarter ended March 31, 2015 compared to the same period 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 Eagle Ford, Wolfcamp 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 March 31,			
	2015		2014	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(6.49)	$(0.50)	$(5.70)	$(0.58)
NYMEX	$48.63	$2.98	$98.69	$4.94

The larger oil differentials and deducts in the quarter ended March 31, 2015 were generally a result of a decrease in LLS pricing relative to NYMEX in Eagle Ford, a widening Midland Cushing discount and new contract deductions in Wolfcamp, and higher deducts in Altamont due to increased rail transport instead of deliveries by truck to refineries as a result of refinery maintenance in the first quarter of 2015. The smaller gas differentials and deducts in the quarter ended March 31, 2015 were generally a result of lower excess royalties paid on flared gas.

NGLs sales decreased for the quarter ended March 31, 2015 compared to the same period 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 ended March 31, 2015 compared to the same period in 2014, Eagle Ford NGLs volumes increased by 13% (0.9 MBbls/d) and Wolfcamp NGLs volumes increased by 63% (1.5 MBbls/d).

Table of Contents

As of March 31, 2015, the NYMEX spot price of a barrel of oil was $47.60 versus the NYMEX spot price of a MMBtu of natural gas of $2.64, or a ratio of 18 to 1. Despite further recent declines in oil prices, the value difference between these commodities is such that we will continue to target increases in our oil volumes in our capital budget. Growth in our overall oil sales (including the impact of financial derivatives) will largely be impacted by our ability to grow these volumes and will also be impacted by commodity pricing to the extent we are unhedged and by the location of our production and the nature of our sales contracts. Based on our hedges in place as of March 31, 2015, we are approximately 96% hedged (based on the midpoint of our 2015 production guidance) at a weighted average price of $91.16 per barrel for the remainder of 2015. These hedge positions consist of 95% fixed price swaps and three way collars (locking in $15.00 per barrel in excess of market prices should Brent settle below $85.00) comprising the remaining positions.

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 March 31, 2015, we recorded $203 million of derivative gains compared to derivative losses of $135 million during the quarter ended March 31, 2014.

Operating Expenses

Transportation costs. Transportation costs for the quarters ended March 31, 2015 and 2014 were $27 million and $23 million, respectively. Total transportation costs have increased for the quarter ended March 31, 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 quarters ended March 31, 2015 and 2014 were $47 million and $44 million, respectively. Total lease operating expense increased in the first quarter of 2015 compared to the same period in 2014 due to higher disposal, maintenance and compression costs in Wolfcamp by approximately $7 million associated with growing production volumes in this area, offset by a decrease in lease operating expense of approximately $4 million in Eagle Ford mainly due to lower chemical and power costs.

General and administrative expenses. General and administrative expenses for the quarters ended March 31, 2015 and 2014 were $47 million and $133 million, respectively. The overall decrease of $86 million for the quarter ended March 31, 2015 was due to the payment in 2014 of advisory fees of $6.25 million and a transaction fee of $83 million paid to our Sponsors under a Management Fee Agreement upon completion of our initial public offering. These agreements terminated with the completion of our initial public offering. In addition, the overall decrease reflects lower payroll, benefits and administrative costs of $5 million compared to the same period in 2014 from lower headcount. 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 quarters ended March 31, 2015 and 2014 were $224 million and $192 million, respectively. Our depreciation, depletion and amortization costs increased in the first quarter of 2015 compared to the same period 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 ended March 31 were:

	Quarters ended March 31,	
	2015	2014
Depreciation, depletion and amortization ($/Boe)(1)	$24.30	$23.47

(1) Includes $0.07 per Boe for both of the quarters ended March 31, 2015 and 2014 related to accretion expense on asset retirement obligations.

Exploration and other expense. For the quarter ended March 31, 2015, we recorded $6 million of exploration expense compared to $8 million for the same period in 2014. Included in exploration expense for the quarters ended March 31, 2015 and 2014 is $4 million and $7 million, respectively, of amortization of unproved leasehold costs. In addition, in the first quarter of 2015, we recorded approximately $2 million as other expense in conjunction with the early termination of a contract for drilling rigs.

Table of Contents

Taxes, other than income taxes. Taxes, other than income taxes for the quarters ended March 31, 2015 and 2014 were $22 million and $33 million, respectively. Production taxes decreased in the first quarter of 2015 compared to the same period 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 ended March 31:

	Quarters ended March 31,			
	2015		2014	
	Total	Per Unit[1]	Total	Per Unit[1]
	(in millions, except per unit costs)			
Total continuing operating expenses	$380	$41.27	$436	$53.40
Depreciation, depletion and amortization	(224)	(24.30)	(192)	(23.47)
Transportation costs	(27)	(2.90)	(23)	(2.85)
Exploration expense[2]	(5)	(0.51)	(8)	(0.99)
Natural gas purchases	(7)	(0.74)	(3)	(0.43)
Total continuing cash operating costs	117	12.82	210	25.66
Transition/restructuring costs, non-cash portion of compensation expense and other[3]	(12)	(1.38)	(100)	(12.20)
Total adjusted cash operating costs and adjusted per-unit cash operating costs	$105	$11.44	$110	$13.46
Total equivalent volumes (MBoe)	9,218		8,166	

(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 March 31, 2015, amount includes approximately $8 million of transition and severance costs related to restructuring and $5 million of non-cash compensation expense. For the quarter ended March 31, 2014, amount includes $90 million of transaction, management and other fees paid to our Sponsors, $9 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.

Table of Contents

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

	Quarters ended March 31, 2015	2014
Average cash operating costs ($/Boe)		
Lease operating expenses	$5.12	$5.42
Production taxes[1]	2.13	3.72
General and administrative expenses[2]	5.09	16.24
Taxes, other than production and income taxes	0.28	0.28
Other expenses[3]	0.20	—
Total cash operating costs	12.82	25.66
Transition/restructuring costs, non-cash portion of compensation expense and other[2]	(1.38)	(12.20)
Total adjusted cash operating costs	$11.44	$13.46

(1) Production taxes include ad valorem and severance taxes which decreased during the quarter ended March 31, 2015 due 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.

Other Income Statement Items.

Loss on extinguishment of debt. For the quarter ended March 31, 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 for the quarter ended March 31, 2015 increased by $5 million compared to the same period in 2014 due to higher interest expense related to our RBL Facility and the additional losses in 2015 compared to 2014 due to changes in the fair market value of our interest rate derivative instruments, partially offset by a decrease due to the retirement of the PIK toggle note.

Income from discontinued operations. Our income from discontinued operations for the quarter ended March 31, 2014 includes the financial results of assets classified as discontinued operations and any gain (loss) recorded on the sale of these non-core domestic natural gas and other assets in 2014.

Table of Contents

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 our 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 income (loss):

	Quarters ended March 31,	
	2015	2014
	(in millions)	
Net income (loss)	$19	$(90)
Income from discontinued operations, net of tax	—	(10)
Income (loss) from continuing operations	19	(100)
Income tax expense (benefit)	10	(56)
Interest expense, net of capitalized interest	84	79
Depreciation, depletion and amortization	224	192
Exploration expense(1)	5	8
EBITDAX	342	123
Mark-to-market on financial derivatives(2)	(203)	135
Cash settlements and premiums on financial derivatives(3)	214	(25)
Non-cash portion of compensation expense(4)	5	9
Transition, restructuring and other costs(5)	8	1
Fees paid to Sponsors(6)	—	90
Loss on extinguishment of debt(7)	—	17
Adjusted EBITDAX	$366	$350

(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 for the quarter ended March 31, 2015. For the quarter ended March 31, 2014, we received less than $1 million of cash premiums.

(4) For the quarters ended March 31, 2015 and 2014, cash payments were less than $1 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 retirement of the PIK toggle note in 2014.

Table of Contents

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 March 31, 2015, our available liquidity was approximately $1.7 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 and senior secured notes are retired or refinanced six months prior to maturity.

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 recent 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 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 March 31, 2015, we are approximately 96% hedged (based on the midpoint of our 2015 production guidance) at a weighted average price of $91.16 per barrel for the remainder of 2015. These hedge positions consist of 95% fixed price swaps and three way collars (locking in $15.00 per barrel in excess of market prices should NYMEX settle below $85.00) comprising the remaining hedge positions.

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

Capital Expenditures. For 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 based on the expected returns in this program. Our capital expenditures and average drilling rigs by area for the quarter ended March 31, 2015 were:

	Capital Expenditures (in millions)	Average Drilling Rigs
Eagle Ford Shale	$288	5.0
Wolfcamp Shale	74	2.0
Altamont	48	2.0
Haynesville Shale	5	0.1
Total capital expenditures	$415	9.1

Long-Term Debt. As of March 31, 2015, our long-term debt is approximately $4.7 billion, comprised of $3.1 billion in senior notes due in 2019, 2020 and 2022, $646 million in senior secured term loans with maturity dates in 2018 and 2019, and $980 million 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.

Table of Contents

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

	Quarters ended March 31, 2015	2014
Cash Flow from Operations		
Operating activities		
Net income (loss)	$19	$(90)
Gain on sale of assets	—	(13)
Other income adjustments	247	183
Changes in assets and liabilities	25	143
Total cash flow from operations	$291	$223
Other Cash Inflows		
Investing activities		
Proceeds from the sale of assets	$—	$17
Financing activities		
Proceeds from issuance of long-term debt	364	550
Proceeds from issuance of stock	—	669
	364	1,219
Total cash inflows	$364	$1,236
Cash Outflows		
Investing activities		
Capital expenditures	$432	$459
Financing activities		
Repayments of long-term debt	236	964
	236	964
Total cash outflows	$668	$1,423
Net change in cash and cash equivalents	$(13)	$36

Table of Contents

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 March 31, 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]	$1,034	$830	$(204)	$1,237	$203

		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]	$1,034	$1,026	$(8)	$1,042	$8
Credit rate[3]	$1,034	$1,024	$(10)	$1,039	$5

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

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

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 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 March 31, 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 quarter of 2015 that materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Table of Contents

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: April 30, 2015	/s/ Dane E. Whitehead Dane E. Whitehead Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: April 30, 2015	/s/ Francis C. Olmsted III Francis C. Olmsted III Vice President and Controller (Principal Accounting Officer)

Table of Contents

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
*10.1	Third Amendment, dated as of October 27, 2014, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent.
10.2	Fourth Amendment, dated as of April 6, 2015, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent (Exhibit 10.1 to Company's Current Report on Form 8 K, filed with the SEC on April 6, 2015).
*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.