EP Energy Corp
Form 10-Q
May 09, 2014
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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 March 31, 2014

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the 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 May 2, 2014: 244,979,094

Class B Common Stock, par value $0.01 per share. Shares outstanding as of May 2, 2014: 872,586

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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
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
MMGal	=	million gallons
MMBtu	=	million British thermal units
MMBbls	=	million barrels
MMcf	=	million cubic feet
MMcfe	=	million cubic feet of natural gas equivalents
NGLs	=	natural gas liquids
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 our 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 2013 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)

	Quarter ended March 31, 2014	Quarter ended March 31, 2013
Operating revenues		
Oil	$ 411	$ 266
Natural gas	87	82
NGLs	27	15
Financial derivatives	(135)	(131)
Total operating revenues	390	232
Operating expenses		
Natural gas purchases	3	2
Transportation costs	26	22
Lease operating expense	47	38
General and administrative	133	58
Depreciation, depletion and amortization	198	125
Exploration expense	8	13
Taxes, other than income taxes	34	23
Total operating expenses	449	281
Operating loss	(59)	(49)
Earnings from unconsolidated affiliate		2
Loss on extinguishment of debt	(17)	(1)
Interest expense	(79)	(92)
Loss from continuing operations before income taxes	(155)	(140)
Income tax benefit	(56)	
Loss from continuing operations	(99)	(140)
Income from discontinued operations, net of tax	9	26
Net loss	$ (90)	$ (114)
Basic and diluted net income (loss) per common share		
Loss from continuing operations	$ (0.42)	$ (0.67)
Discontinued operations, net of tax	0.04	0.12
Net loss	$ (0.38)	$ (0.55)
Basic and diluted weighted average common shares outstanding	238	209

See accompanying notes.

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)

(Unaudited)

	March 31, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 87	$ 51
Accounts receivable		
Customer, net of allowance of less than $1 in 2014 and 2013	278	239
Other, net of allowance of $1 in 2014 and $2 in 2013	25	44
Materials and supplies	22	20
Derivative instruments	16	47
Assets of discontinued operations	73	88
Deferred income taxes	46	28
Prepaid assets	9	12
Total current assets	556	529
Property, plant and equipment, at cost		
Oil and natural gas properties	8,814	8,371
Other property, plant and equipment	73	63
	8,887	8,434
Less accumulated depreciation, depletion and amortization	1,005	818
Total property, plant and equipment, net	7,882	7,616
Other assets		
Derivative instruments	49	97
Unamortized debt issue costs	106	116
Other	8	8
	163	221
Total assets	$ 8,601	$ 8,366

See accompanying notes.

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)

(Unaudited)

	March 31, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 173	$ 140
Other	379	392
Derivative instruments	66	35
Accrued interest	107	54
Asset retirement obligations	3	3
Liabilities of discontinued operations	81	91
Other accrued liabilities	53	65
Total current liabilities	862	780
Long-term debt	4,020	4,421
Other long-term liabilities		
Derivative instruments	1	
Deferred income taxes	139	171
Asset retirement obligations	50	50
Other	9	7
Total non-current liabilities	4,219	4,649
Commitments and contingencies (Note 8)		
Stockholders equity		
Class A shares, $0.01 par value; 550 million shares authorized; 244 million shares issued and outstanding at March 31, 2014; 209 million shares issued and outstanding at December 31, 2013	2	
Class B shares, $0.01 par value; 0.9 million shares authorized, issued and outstanding at March 31, 2014 and December 31, 2013		
Preferred stock, $0.01 par value; 50 million authorized; none issued or outstanding		
Additional paid-in capital	3,503	2,832
Retained earnings	15	105
Total stockholders equity	3,520	2,937
Total liabilities and equity	$ 8,601	$ 8,366

See accompanying notes.

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

(Unaudited)

	Quarter ended March 31, 2014	Quarter ended March 31, 2013
Cash flows from operating activities		
Net loss	$ (90)	$ (114)
Adjustments to reconcile net loss to net cash provided by operating activities		
Depreciation, depletion and amortization	198	149
Gain on sale of assets	(13)	
Impairment charges	3	
Deferred income tax benefit	(51)	
Earnings from unconsolidated affiliate, net of cash distributions		6
Loss on extinguishment of debt	17	1
Amortization of equity compensation expense	4	7
Non-cash portion of exploration expense	7	12
Amortization of debt issuance costs	5	5
Asset and liability changes		
Accounts receivable	(16)	(18)
Accounts payable	6	16
Derivative instruments	111	159
Accrued interest	53	52
Other asset changes	4	(24)
Other liability changes	(15)	(17)
Net cash provided by operating activities	223	234
Cash flows from investing activities		
Capital expenditures	(459)	(444)
Net proceeds from the sale of assets	17	10
Net cash used in investing activities	(442)	(434)
Cash flows from financing activities		
Proceeds from long-term debt	550	390
Repayment of long-term debt	(964)	(180)
Proceeds from issuance of stock	669	
Debt issuance costs		(3)
Net cash provided by financing activities	255	207
Change in cash and cash equivalents	36	7
Cash and cash equivalents		
Beginning of period	51	64
End of period	$ 87	$ 71

See accompanying notes

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(In millions)

(Unaudited)

	Stockholder s Equity												
	Class A Stock			Class B Stock			Additional Paid-in Capital		Retained Earnings		Total	
	Shares	Amount		Shares	Amount							
Balance at December 31, 2013	209	$		0.9	$		$	2,832	$	105	$	2,937
Compensation expense								4				4
Stock issuance	35		2					667				669
Net loss										(90)		(90)
Balance at March 31, 2014	244	$	2	0.9	$		$	3,503	$	15	$	3,520

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 Stated Securities and Exchange Commission (SEC) and in accordance with United States generally accepted accounting principles as it applies to interim condensed consolidated financial statements. Because this is an interim period report presented using a condensed format, it does not include all of the disclosures required by United States generally accepted accounting principles and should be read along with our 2013 Annual Report on Form 10-K. The condensed consolidated financial statements as of March 31, 2014 and 2013 are unaudited. The consolidated balance sheet as of December 31, 2013 has been derived from the audited consolidated balance sheet included in our 2013 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 2013 Annual Report on Form 10-K.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standard has been issued but not yet been adopted.

Discontinued Operations. In April 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-08, *Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*, which alters the criteria under which assets to be disposed of are evaluated for reporting as a discontinued operation. While early adoption of this standards update is permitted, prospective application is required in the first quarter of 2015. Accordingly, the standard will not impact our historical presentation of assets as discontinued operations. We are currently evaluating the requirements of the standards update that could impact future disposal transactions subsequent to implementation.

2. Acquisitions and Divestitures

Discontinued Operations. We have reflected as discontinued operations certain domestic natural gas assets sold in 2013 (including CBM properties located in the Raton, Black Warrior and Arkoma basins; Arklatex conventional natural gas assets located in East Texas and North Louisiana and legacy South Texas conventional natural gas assets) and our Brazilian operations which are under contract to be sold. We expect to complete the sale in 2014 which is awaiting Brazilian regulatory approval as well as certain other customary closing conditions. In the first quarter of 2014, we completed the sale of certain additional domestic natural gas assets in our Arklatex area for approximately $16 million and recorded a gain on the sale of approximately $13 million, which is reflected in income from discontinued operations.

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

	Quarter ended March 31, 2014	Quarter ended March 31, 2013
Operating revenues	$ 17	$ 105
Operating expenses		
Natural gas purchases		8
Transportation costs		7
Lease operating expense	10	26
Depreciation, depletion and amortization		24
Impairment charges(1)	3	
Other expense	4	14
Total operating expenses	17	79
Gain on sale of assets	13	
Other income	3	1
Income from discontinued operations before income taxes	16	27
Income tax expense	7	1
Income from discontinued operations, net of tax	$ 9	$ 26

(1) During the quarter ended March 31, 2014, we recorded $3 million in impairment charges to impair earnings subsequent to entering into a Quota Purchase Agreement to sell our Brazil operations in 2013.

	March 31, 2014	December 31, 2013
Assets of discontinued operations		
Current assets	$ 20	$ 26
Property, plant and equipment, net	49	52
Other non-current assets	4	10
Total assets of discontinued operations	$ 73	$ 88
Liabilities of discontinued operations		
Accounts payable	$ 39	$ 39
Other current liabilities	5	10
Asset retirement obligations	37	37
Other non-current liabilities		5
Total liabilities of discontinued operations	$ 81	$ 91

Other Acquisitions and Divestitures. During the first quarter of 2013, we received approximately $10 million from the sale of certain domestic oil and natural gas properties. No gain or loss was recorded on this sale.

On April 30, 2014, we announced the acquisition of approximately 37,000 net acres of certain producing properties and undeveloped acreage in the Southern Midland Basin adjacent to our existing Wolfcamp Shale position. The acquisition represents an approximate 25 percent expansion of our current Wolfcamp acreage. We also entered into an agreement to divest certain non-core assets in the Arklatex and South Louisiana Wilcox areas (approximately 78,000 net acres). The aggregate cash purchase price for the acquired properties is $153 million, while the divested properties will generate $150 million of cash proceeds, with the buyer also assuming a transportation liability of approximately $20 million. The assets to be sold will be presented as discontinued operations beginning in the second quarter.

3. Income Taxes

General. Prior to August 30, 2013, we conducted our activities through EPE Acquisition, LLC, a holding company formed on February 14, 2012. On August 30, 2013, we reorganized our structure to form EP Energy Corporation, a new corporate holding Company (Corporate Reorganization). As a result of the Corporate Reorganization, we became a corporation subject to federal and state income taxes. Accordingly, we began recording the effects of income taxes in our financial statements. We are not currently subject to any U.S. or state income tax audits and we have no uncertain tax positions from our continuing operations.

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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 ended March 31, 2014, we recorded an income tax benefit of $56 million (deferred income tax benefit of $57 million and current tax expense of $1 million) resulting in an effective tax rate of 36%. Our effective tax rate for the quarter ended March 31, 2014 includes the effects of state income taxes and non-deductible compensation expense, substantially offset by the tax effects of discrete adjustments for certain transaction costs related to our initial public offering. For the quarter ended March 31, 2013, we were a partnership not subject to federal and state income taxes. If we had recorded income taxes effective January 1, 2013, through March 31, 2013, pro forma loss from continuing operations would have been approximately $91 million based on applying a federal statutory tax rate of 35%.

4. Earnings Per Share

On January 2, 2014, we completed a 62.553-for-1 stock split of our common stock. For the quarter ended March 31, 2013, we retrospectively reflected earnings per common share/earnings per member unit (each member unit was converted into an equivalent common share in connection with the August 2013 Corporate Reorganization), giving effect to the stock split. On January 23, 2014, we completed a public offering of 35.2 million shares of Class A Common Stock, $0.01 par value per share. For each financial statement period presented, there were no dilutive securities for purposes of calculating diluted earnings per share.

5. Financial Instruments

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

	March 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt	$ 4,020	$ 4,432	$ 4,421	$ 4,841
Derivative instruments (liability)/asset	$ (2)	$ (2)	$ 109	$ 109

As of March 31, 2014 and December 31, 2013, 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 those 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, natural gas and NGLs through the use of fixed price hedges. As of March 31, 2014 and December 31, 2013, we had total derivative contracts on 49 MMBbls and 47 MMBbls of oil and 123 TBtu and 135 TBtu of natural gas, respectively. As of March 31, 2014, we also had derivative contracts on 35 MMGal of propane. None of these contracts are designated as accounting hedges. As of May 6, 2014, we added 1.5 MMBbls of LLS fixed price oil swaps to our anticipated 2016 production and 3.7 TBtu of fixed price natural gas swaps to our anticipated 2015 production.

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, 2014 and December 31, 2013, we had a net asset of $4 million related to interest rate derivative instruments included in our consolidated balance sheets. For each of the quarters ended March 31, 2014 and 2013, we recorded $1 million in interest expense related to the change in fair market value and cash settlements of our interest rate derivative instruments.

Fair Value Measurements. We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair values of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of March 31, 2014 and December 31, 2013, all financial instruments were classified as Level 2. Our assessment of an instrument within a level can change over time based on the maturity or liquidity of the instrument, which could result in a change in the classification of our financial instruments between other levels.

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Financial Statement Presentation. The following table presents the fair value associated with derivative financial instruments as of March 31, 2014 and December 31, 2013. All of our derivative instruments are subject to master netting arrangements which provide for the unconditional right of offset for all derivative assets and liabilities with a given counterparty in the event of default. We present assets and liabilities related to these instruments in our balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

	Level 2							
	Derivative Assets				Derivative Liabilities			
	Gross(1)		Balance Sheet Location		Gross(1)		Balance Sheet Location	
	Fair value	Impact of Netting	Current	Non-current	Fair value	Impact of Netting	Current	Non-current
	(in millions)				(in millions)			
March 31, 2014								
Derivatives	$ 110	$ (45)	$ 16	$ 49	$ (112)	$ 45	$ (66)	$ (1)
December 31, 2013								
Derivatives	$ 164	$ (20)	$ 47	$ 97	$ (55)	$ 20	$ (35)	$

(1) Gross derivative assets are comprised primarily of $103 million of oil, natural gas and NGLs derivatives as of March 31, 2014 and $157 million of oil and natural gas derivatives as of December 31, 2013 and $7 million of interest rate derivatives for each of the periods ended March 31, 2014 and December 31, 2013. Gross derivative liabilities are comprised primarily of $109 million of oil, natural gas and NGLs derivatives as of March 31, 2014 and $52 million of oil and natural gas derivatives as of December 31, 2013 and $3 million of interest rate derivatives for each of the periods ended March 31, 2014 and December 31, 2013.

Losses on oil, natural gas and NGLs financial derivative instruments presented in operating revenues were $135 million for the quarter ended March 31, 2014. Losses on oil and natural gas financial derivative instruments were $131 million for the quarter ended March 31, 2013.

6. Property, Plant and Equipment

General. As of March 31, 2014 and December 31, 2013, we had $1.2 billion and $1.4 billion of unproved oil and natural gas properties on our balance sheet. During the first quarter of 2014, we transferred approximately $0.2 billion from unproved properties to proved properties. For the quarters ended March 31, 2014 and 2013 we recorded $7 million and $12 million of amortization of unproved leasehold costs in exploration expense in our income statement. Suspended well costs were not material as of March 31, 2014 or December 31, 2013. For a discussion of our impairment assessment of oil and natural gas properties see Note 3 to our Annual Report on Form 10-K.

Asset Retirement Obligations. We have legal asset retirement obligations associated with the retirement of our oil and natural gas wells and related infrastructure. We incur these obligations when production on those wells is exhausted, when we no longer plan to use them or when we abandon them. We accrue these obligations when we can estimate the timing and amount of their settlement. In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate of 7 percent and a projected inflation rate of 2.5 percent. The net asset retirement liability as of March 31, 2014 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, 2014 were as follows:

		2014 (in millions)
Net asset retirement liability at January 1	$	53
Liabilities settled		(1)
Property sale		(1)
Accretion expense		1
Liabilities incurred		1
Net asset retirement liability at March 31(1)	$	53

(1) Amount does not include $37 million as of March 31, 2014 of net asset retirement liability associated with our Brazil operations classified as discontinued operations.

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. Capitalized interest for each of the quarters ended March 31, 2014 and 2013 was approximately $5 million.

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7. Long-Term Debt

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

	Interest Rate		March 31, 2014 (in millions)
$2.5 billion RBL credit facility - due May 24, 2017	Variable	$	275
$750 million senior secured term loan - due May 24, 2018(1)(3)	Variable		495
$400 million senior secured term loan - due April 30, 2019(2)(3)	Variable		150
$750 million senior secured notes - due May 1, 2019(3)	6.875%		750
$2.0 billion senior unsecured notes - due May 1, 2020	9.375%		2,000
$350 million senior unsecured notes - due September 1, 2022	7.75%		350
Total		$	4,020

(1) The term loan was issued at 99 percent of par and carries interest at a specified margin over the LIBOR of 4.00%, with a minimum LIBOR floor of 1.00%. As of March 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%.

(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, 2014 and December 31, 2013, we had $106 million and $116 million, respectively, in deferred financing costs on our consolidated balance sheets. During each of the quarters ended March 31, 2014 and 2013, we amortized $5 million of deferred financing costs. These costs are included 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. During the quarters ended March 31, 2014 and 2013, we recorded $17 million and $1 million in losses on the extinguishment of debt in our consolidated income statement as a result of the retirement of the PIK toggle note in 2014 and to reflect the pro-rata portion of deferred financing costs written off in conjunction with the semi-annual redetermination of our RBL Facility in March 2013.

$2.5 Billion Reserve-based Loan (RBL). Under the RBL Facility, we can borrow funds or issue letters of credit and as of March 31, 2014, we had a $2.5 billion RBL borrowing base, $275 million of outstanding borrowings and approximately $8 million of letters of credit issued under the facility, leaving $2.2 billion of remaining capacity. As of May 6, 2014, we had $700 million in outstanding borrowings under the facility.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redeterminations. In April 2014, we completed our semi-annual redetermination maintaining the borrowing base of our RBL Facility at $2.5 billion. 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 March 31, 2014, we were in compliance with all of our debt covenants. For a further discussion of our debt agreements and restrictive covenants, see our 2013 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, 2014, we had approximately $1 million accrued for all outstanding legal matters.

Southeast Louisiana Flood Protection Authority v. EP Energy Management, L.L.C. The levee authority for New Orleans and surrounds has filed a lawsuit against 97 oil, gas and pipeline companies, seeking (among other relief) restoration of wetlands allegedly lost due to historic industry operations in those areas. The suit, which does not specify an amount of damages, was filed in Louisiana state court in New Orleans but then removed to the U.S. District Court for the Eastern District of Louisiana. The Louisiana State Legislature is considering legislation that could result in dismissal of the lawsuit. Our subsidiary, EP Energy Management, L.L.C., is named as successor to Colorado Oil Company, Inc. and Gas Producing Enterprises as operators of five wells from the mid-1970s to 1980. The validity of the causes of action as well as our costs and legal exposure, if any, related to the lawsuit are not currently determinable.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestitures of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities, for example, plugging and abandonment obligations for assets no longer owned or operated by us. As of March 31, 2014, we had approximately $5 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, 2014, we had accrued 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 exposure could be as high as $3 million. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts that we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

Climate Change and Other Emissions. The Environmental Protection Agency (EPA) and several state environmental agencies have adopted regulations to regulate GHG emissions. Although the EPA has adopted a tailoring rule to regulate GHG emissions, at this time we do not expect a material impact to our existing operations. There have also been various legislative and regulatory proposals and final rules at the federal and state levels to address emissions from power plants and industrial boilers. Although such rules and proposals will generally favor the use of natural gas over other fossil fuels such as coal, it remains uncertain what regulations will ultimately be adopted and when they will be adopted. As part of the White House s Climate Action Plan, the EPA intends to examine technical white papers about methane emissions in the oil and gas industry and may propose additional regulations in 2016. Further, the Bureau of Land Management may propose additional regulations for public lands in 2014. 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.

The EPA has promulgated regulations to require pre-construction permits for minor sources of air emissions in tribal lands as of September 2, 2014. On January 14, 2014, the EPA proposed extending this deadline twelve to eighteen months, during which time the EPA anticipates separate rulemaking to create general permits for true minor sources in the oil and gas production industry. Comments to the EPA s proposed extension were due March 17, 2014. Until such regulations are adopted, it is uncertain what impact they might have on our operations in tribal lands.

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

Hydraulic Fracturing Regulations. We use hydraulic fracturing extensively in our operations. Various regulations have been adopted and proposed at the federal, state and local levels to regulate hydraulic fracturing operations. These regulations range from banning or substantially limiting hydraulic fracturing operations, requiring disclosure of the hydraulic fracturing fluids and requiring additional permits for the use, recycling and disposal of water used in such operations. In addition, various agencies, including the EPA, the Department of Interior and Department of Energy are reviewing changes in their regulations to address the environmental impacts of hydraulic fracturing operations. Until such regulations are implemented, it is uncertain what impact they might have on our operations.

Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) Matters. As part of our environmental remediation projects, we are or have received notice that we could be designated as a Potentially Responsible Party (PRP) with respect to one active site under the CERCLA or state equivalents. As of March 31, 2014, 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.

9. Long-Term Incentive Compensation

Our long-term incentive (LTI) awards currently include a cash-based incentive award and certain equity-based programs. Each of these awards are further described in our 2013 Annual Report on Form 10-K.

Compensation expense (recorded as general and administrative expense on our income statement) related to all of our long-term incentive awards was approximately $9 million and $13 million during the quarters ended March 31, 2014 and 2013, respectively. As of March 31, 2014, we had unrecognized compensation expense of $50 million. We will recognize an additional $14 million related to outstanding awards as of March 31 during the rest of 2014, $17 million over the remaining requisite service periods subsequent to 2014 and $19 million upon a specified capital transaction when the right to such amounts become non-forfeitable.

10. Investment in Unconsolidated Affiliate

In September 2013, we sold our equity investment in Four Star Oil & Gas Company (Four Star) for net proceeds of $183 million. For the quarter ended March 31, 2013, we recorded $2 million in earnings from unconsolidated affiliate reflecting $5 million for our share of net equity earnings directly attributable to Four Star and $3 million of amortization of the excess of the carrying value of our investment relative to the underlying equity in the net assets of the entity. Total operating revenues, operating expenses and net income of Four Star for the quarter ended March 31, 2013 were $49 million, $33 million, and $9 million, respectively. For the quarter ended March 31, 2013, we received dividends from Four Star of approximately $8 million.

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11. 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 Global Management LLC, Riverstone Holdings LLC, Access Industries and Korea National Oil Corporation, collectively the Sponsors). Additionally, subject to the terms and conditions of the amended and restated Management Fee Agreement, upon the closing of our initial public offering in January 2014, we paid the Sponsors an additional transaction fee equal to approximately $83 million (the lesser of (i) 1% of the aggregate enterprise value paid or provided by the Company Group and (ii) $100,000,000). We recorded both of these fees in general and administrative expense for the quarter ended March 31, 2014. The amended and restated Management Fee Agreement, including the obligation to pay the quarterly management fee, terminated automatically in accordance with its terms upon the closing of our initial public offering.

Affiliate Supply Agreement. As of March 31, 2014, we have recorded approximately $160 million, cumulatively, in capital expenditures for amounts provided under a supply agreement with an Apollo affiliate through October 2014 to provide certain fracturing materials for our Eagle Ford drilling operations.

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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 2013 Annual Report on Form 10-K. Actual results may differ materially from those contained in any forward-looking statements. All periods included in these interim financial statements present our Brazil operations and certain domestic natural gas assets sold noted below 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 our four core 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). We also have other domestic activities in Texas and Louisiana. Further information regarding each of our core programs is below:

- ***Eagle Ford Shale.*** The Eagle Ford Shale continues to provide the highest economic returns in our portfolio. We currently are running six rigs in this program.

- ***Wolfcamp Shale.*** In our Wolfcamp Shale program, we are focused on optimizing our drilling, completion and artificial lift systems. We currently are running four rigs in this program.

- ***Altamont.*** In Altamont, we are gaining operational efficiencies as we develop this oil-based field. Most of our acreage in this area is held-by-production. At the end of April 2014, we released the fourth rig and are currently running three rigs in this program.

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

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

On April 30, 2014, we announced the acquisition of approximately 37,000 net acres of certain producing properties and undeveloped acreage in the Southern Midland Basin adjacent to our existing Wolfcamp Shale position for an aggregate cash purchase price of $153 million. The acquisition represents an approximate 25 percent expansion of our current Wolfcamp acreage. The acquired properties are 100 percent operated with net production of approximately 1,000 Boe/d which is 75 percent liquids. We expect to integrate the acquired properties into our existing development program with minimal 2014 capital.

Additionally, we also entered into an agreement to divest certain non-core assets in the Arklatex and South Louisiana Wilcox areas (approximately 78,000 net acres) for $150 million of cash proceeds with the buyer also assuming a transportation liability of approximately $20 million. Net estimated annual production associated with the divested properties is approximately 21 MMcfe/d, approximately 85 percent of which is natural gas. We expect to complete the sale in the second quarter of 2014 and use the proceeds to offset the funds used for the acquisition noted above. We will present these assets to be sold as discontinued operations beginning in the second quarter.

We have reflected as discontinued operations certain domestic natural gas assets sold in 2013 (including CBM properties located in the Raton, Black Warrior and Arkoma basins; Arklatex conventional natural gas assets located in East Texas and North Louisiana and legacy South Texas conventional natural gas assets) and our Brazilian operations which are under contract to be sold. We expect the sale (which represents the sale of all of our remaining international assets) to close in 2014, subject to Brazilian regulatory approval and certain other customary closing conditions. During the first quarter of 2014, we sold additional domestic natural gas assets in our Arklatex area for approximately $16 million and recorded a gain on sale of approximately $13 million, which is reflected in income from discontinued operations.

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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, or domestic or international regulatory issues or other third party actions outside of our control (e.g., oil spills).

To the extent possible, we attempt to mitigate certain of these risks through actions such as entering into longer term contractual arrangements to control costs and entering into derivative contracts to stabilize cash flows and reduce the financial impact of downward commodity price movements on commodity sales. In addition, because we apply mark-to-market accounting, our reported results of operations and statement of 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, natural gas and NGLs 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, natural gas, or NGLs, 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. During the quarter ended March 31, 2014, we (i) settled commodity index hedges on approximately 94% of our liquids (oil and NGLs) production and 96% of our natural gas production at average floor prices of $98.11 per barrel and $4.02 per MMBtu, respectively and (ii) settled basis hedges on approximately 53% of our estimated Eagle Ford oil production. To the extent our oil, natural gas, and NGL production is unhedged, either from a commodity index price or locational price perspective, our financial results will be impacted from period to period. See Operating Revenues discussion for more information. The following table reflects the contracted volumes and the prices we will receive under derivative contracts we held as of March 31, 2014.

	2014	**2015**	**2016**

	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)
Oil									
Fixed Price Swaps									
WTI	9,611	$	97.06	17,373	$	89.34	5,216	$	85.25
Brent	2,750	$	102.57	2,555	$	100.01	4,026	$	95.01
LLS(2)		$			$		2,562	$	93.96
Ceilings	916	$	100.41	1,095	$	100.00		$	
Three Way Collars									
Ceiling - WTI	2,200	$	103.76		$			$	
Floors - WTI(3)	2,200	$	95.00		$			$	
Ceiling - Brent		$		1,095	$	110.02		$	
Floors - Brent(4)		$		1,095	$	100.00		$	
Basis Swaps									
LLS vs. WTI(5)(7)	2,655	$	5.56		$		183	$	3.00
LLS vs. Brent(6)(7)	2,750	$	(3.72)	3,650	$	(3.77)	1,830	$	(1.89)
Midland vs. Cushing(8)	459	$	(1.36)		$			$	
Natural Gas									
Fixed Price Swaps	57	$	4.02	58	$	4.26	7	$	4.20
NGLs									
Propane Fixed Price Swaps	23	$	1.14		$			$	
Propane Collars									
Ceilings	12	$	1.30		$			$	
Floors	12	$	1.00		$			$	

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

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

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

(4) 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.

(5) EP Energy receives WTI plus basis spread listed and pays LLS.

(6) EP Energy receives Brent less basis spread listed and pays LLS.

(7) Represents an effective floor price on the hedged production of $100.70 per Bbl for 2014, $96.24 per Bbl for 2015 and $93.40 per Bbl for 2016. Floor prices do not include customary refinery and contract deductions.

(8) EP Energy receives Cushing less basis spread listed and pays Midland.

As of May 6, 2014, we added LLS fixed price oil swaps of 1.5 MMBbls to our anticipated 2016 production with an average price of $89.08 per Bbl and 3.7 TBtu of fixed price natural gas swaps to our anticipated 2015 production with an average price of $4.37 per MMBtu. These derivative instruments are not included in the table above.

Summary of Liquidity and Capital Resources. As of March 31, 2014, we had available liquidity, including existing cash, of approximately $2.3 billion. We believe we have sufficient liquidity for 2014 from our cash flows from operations, combined with the availability under our RBL Facility and available cash, to fund our current obligations, projected working capital requirements and capital spending plan. In April 2014, we completed our semi-annual redetermination maintaining the borrowing base of our RBL Facility at $2.5 billion. Additionally, the earliest maturity date of our debt obligations is in 2017. See Liquidity and Capital Resources for more information.

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

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

- Twenty percent increase in well completions from 2013 to between 265 and 290.

- Average daily production volumes for the year of approximately 93.5 MBoe/d to 99.5 MBoe/d, including average daily oil production volumes of approximately 52 MBbls/d to 55 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately \$12.25 to \$14.25 per Boe, and transportation costs of \$3.00 to \$3.50 per Boe.

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

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Production Volumes and Drilling Summary

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

	2014	2013
United States (MBoe/d)		
Eagle Ford Shale	47	31
Wolfcamp Shale	12	2
Altamont	13	11
Haynesville Shale	19	34
Other	4	6
Core areas and other	95	84
Unconsolidated affiliate (MBoe/d)(1)		9
Total Combined (MBoe/d)	95	93
Oil (MBbls/d)		
Core areas and other volumes	49	31
Unconsolidated affiliate volumes(1)		1
Total Combined	49	32
Natural Gas (MMcf/d)		
Core areas and other volumes	216	288
Unconsolidated affiliate volumes(1)		41
Total Combined	216	329
NGLs (MBbls/d)		
Core areas and other volumes	10	5
Unconsolidated affiliate volumes(1)		1
Total Combined	10	6

(1) In September 2013, we sold our equity investment in Four Star Oil & Gas Company (Four Star).

- *Eagle Ford Shale* Our Eagle Ford Shale equivalent volumes and oil production increased 16 MBoe/d (52%) and 11 MBbls/d (55%), respectively, for the quarter ended March 31, 2014 compared to the same period in 2013 due to the success of our drilling program in the area. During the quarter ended March 31, 2014, we drilled 35 additional operated wells in the Eagle Ford, and we had a total of 304 net operated wells as of March 31, 2014. With a majority of our acreage located in the core of the oil window, primarily in LaSalle and Atascosa counties, we continue to grow our oil and NGLs production in the area.

- *Wolfcamp Shale* Our Wolfcamp Shale equivalent volumes increased 10 MBoe/d (500%) for the quarter ended March 31, 2014 compared to the same period in 2013 as we continue to progress the development of the program. During the first quarter of 2014, we drilled 20 additional operated wells, for a total of 119 net operated wells as of March 31, 2014.

- *Altamont* Our Altamont equivalent volumes increased 2 MBoe/d (18%) for the quarter ended March 31, 2014 compared to the same period in 2013. Altamont produced an average of 10 MBbls/d of oil during the first quarter of 2014, and we drilled an additional 11 operated oil wells for a total of 325 net operated wells at March 31, 2014.

- *Haynesville Shale* Our Haynesville Shale equivalent volumes decreased 90 MMcf/d (44%) for the quarter ended March 31, 2014 compared to the same period in 2013, due to natural production declines. Our Haynesville drilling program remains suspended based on current natural gas prices. As of March 31, 2014, we had 99 net operated wells in the Haynesville Shale, and our total production for the first quarter of 2014 was approximately 112 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.

	Quarter ended March 31, 2014	Quarter ended March 31, 2013
	(in millions)	
Operating revenues		
Oil	$ 411	$ 266
Natural gas	87	82
NGLs	27	15
	525	363
Financial derivatives	(135)	(131)
Total operating revenues	390	232
Operating expenses		
Natural gas purchases	3	2
Transportation costs	26	22
Lease operating expense	47	38
General and administrative	133	58
Depreciation, depletion and amortization	198	125
Exploration expense	8	13
Taxes, other than income taxes	34	23
Total operating expenses	449	281
Operating loss	(59)	(49)
Earnings from unconsolidated affiliate		2
Loss on extinguishment of debt	(17)	(1)
Interest expense	(79)	(92)
Loss from continuing operations before income taxes	(155)	(140)
Income tax benefit	(56)	
Loss from continuing operations	(99)	(140)
Income from discontinued operations, net of tax	9	26
Net loss	$ (90)	$ (114)

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters ended March 31, 2014 and 2013. 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.

	Quarter ended March 31,	
	2014	2013
	(in millions)	
Operating revenues:		
Oil	$ 411	$ 266
Natural gas	87	82
NGLs	27	15
Total physical sales	525	363
Financial derivatives	(135)	(131)
Total operating revenues	$ 390	$ 232
Volumes:		
Oil		
Consolidated volumes (MBbls)	4,422	2,772
Unconsolidated affiliate volumes (MBbls)(1)		68
Natural gas		
Consolidated volumes (MMcf)	19,477	25,839
Unconsolidated affiliate volumes (MMcf)(1)		3,679
NGLs		
Consolidated volumes (MBbls)	857	477
Unconsolidated affiliate volumes (MBbls)(1)		112
Equivalent volumes		
Consolidated MBoe	8,525	7,555
Unconsolidated affiliate MBoe(1)		794
Total combined MBoe	8,525	8,349
Consolidated MBoe/d	95	84
Unconsolidated affiliate MBoe/d(1)		9
Total Combined MBoe/d	95	93
Consolidated prices per unit(2):		
Oil		
Average realized price on physical sales ($/Bbl)	$ 92.90	$ 96.02
Average realized price, including financial derivatives ($/Bbl)(3)	$ 91.29	$ 103.12
Natural gas		
Average realized price on physical sales ($/Mcf)	$ 4.28	$ 3.11
Average realized price, including financial derivatives ($/Mcf)(3)	$ 3.41	$ 3.42
NGLs		
Average realized price on physical sales ($/Bbl)	$ 32.35	$ 31.57
Average realized price, including financial derivatives ($/Bbl)(3)	$ 31.48	$

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

(2) Natural gas prices for the quarters ended March 31, 2014 and 2013 are calculated including a reduction of $3 million and $2 million, respectively, for natural gas purchases associated with managing our physical gas sales.

(3) The quarters ended March 31, 2014 and 2013, include approximately $7 million of cash paid and approximately $13 million of cash received, respectively, for the settlement of crude oil derivative contracts. The quarters ended March 31, 2014 and 2013 include approximately $17 million of cash paid and approximately $7 million of cash received, respectively, for the settlement of natural gas financial derivatives. The quarter ended March 31, 2014 includes approximately $1 million of cash paid for the settlement of NGLs derivative contracts. The quarters ended March 31, 2014 and 2013 include less than $1 million and approximately $8 million of cash premiums received, respectively.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter ended March 31, 2014, physical sales increased by $162 million (45%) compared to the same period in 2013. The table below displays the price and volume variances on our physical sales when comparing the quarters ended March 31, 2014 and 2013.

	Physical Sales (in millions)			
	Oil	**Natural gas**	**NGLs**	**Total**
March 31, 2013 sales	$ 266	$ 82	$ 15	$ 363
Change due to prices	(14)	25		11
Change due to volumes	159	(20)	12	151
March 31, 2014 sales	$ 411	$ 87	$ 27	$ 525

Oil sales for the quarter ended March 31, 2014 compared to the same period in 2013 increased by $145 million (55%), due primarily to oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. In the first quarter of 2014, Eagle Ford oil production increased by 55% (11 MBbls/d) compared with the quarter ended March 31, 2013. In addition, Wolfcamp and Altamont oil production volumes increased by 375% (6 MBbls/d) and 23% (2 MBbls/d), respectively. For the quarter ended March 31, 2014, realized oil prices, including financial derivatives, were lower when compared to 2013 reflecting the effects of unfavorable unhedged locational or basis differentials and contractual deductions between the commodity price index and the actual price at which we sold our oil.

Natural gas sales for the quarters ended March 31, 2014 and 2013 were $87 million and $82 million, respectively. Natural gas sales increased for the quarter ended March 31, 2014 compared with the same period in 2013 due to higher natural gas prices partially offset by a decrease in volumes due to natural production declines in the Haynesville Shale. Our Haynesville drilling program remains suspended based on current natural gas prices.

NGLs sales increased for the quarter ended March 31, 2014 compared with the same period in 2013. Although average realized prices for the quarter ended March 31, 2014 remained relatively flat compared to the same period in 2013, NGLs volumes grew as a result of our Eagle Ford and Wolfcamp drilling programs. Eagle Ford NGLs volumes increased by 53% (2 MBbls/d) and Wolfcamp NGLs volumes increased by 449% (2 MBbls/d) over the quarter ended March 31, 2013.

As of March 31, 2014, the NYMEX spot price of a barrel of oil was $101.58 versus the NYMEX spot price of natural gas of $4.37, or a ratio of 23 to 1. We have and will continue to target increases in our oil volumes due to this value difference, but we also expect volumes of natural gas to decline with less capital focus in this area. Growth in our revenue will largely be impacted by our ability to grow our oil volumes and by changes in oil prices.

Gains or losses on financial derivatives. We record gains or losses due to cash settlements and changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. During the quarter ended March 31, 2014, we recorded $135 million of derivative losses compared to derivative losses of $131 million during the quarter ended March 31, 2013.

Operating Expenses

Transportation costs. Transportation costs for the quarters ended March 31, 2014 and 2013 were $26 million and $22 million, respectively. Total transportation costs for the quarter ended March 31, 2014 increased as compared to the same period in 2013 primarily due to oil transportation costs associated with our Eagle Ford play as a result of our production growth and new contracts in that area.

Lease Operating Expense. Lease operating expense for the quarters ended March 31, 2014 and 2013 were $47 million and $38 million, respectively. Total lease operating expenses for the quarter ended March 31, 2014 increased as compared to the same period in 2013 due to higher chemical, maintenance, repair and power costs in Eagle Ford and higher disposal and compression costs in Wolfcamp associated with growing production volumes in the two areas.

General and administrative expenses. General and administrative expenses for the quarter ended March 31, 2014 increased $75 million compared to the same period in 2013. The increase for the quarter was primarily due to the recording of a transaction fee of $83 million paid to our Sponsors in January 2014 under the amended and restated Management Fee Agreement upon completion of our initial public offering. Partially offsetting these fees were lower benefits and administrative costs.

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Depreciation, depletion and amortization expense. Our depreciation, depletion and amortization costs increased during the quarter ended March 31, 2014 compared to the same period in 2013 due to the ongoing development of higher cost oil programs (e.g., Eagle Ford and Wolfcamp). We expect our depletion rate will continue to increase as compared to our current levels as a result of the ongoing development of our higher cost liquids programs. Our average depreciation, depletion and amortization costs per unit for the quarters ended March 31 were:

	2014	2013
Depreciation, depletion and amortization ($/Boe)(1)	$ 23.23	$ 16.60

(1) Includes $0.11 per Boe for each of the quarters ended March 31, 2014 and 2013 related to accretion expense on asset retirement obligations.

Exploration expense. For the quarter ended March 31, 2014, we recorded $8 million of exploration expense compared to $13 million for the quarter ended March 31, 2013. Included in exploration expense for the quarters ended March 31, 2014 and 2013 is $7 million and $12 million, respectively, of amortization of unproved property costs.

Taxes, other than income taxes. Taxes, other than income taxes for the quarters ended March 31, 2014 and 2013 were $34 million and $23 million, respectively. Production taxes increased in the first quarter of 2014 compared to the same period in 2013 due to higher severance taxes associated with production volumes in our oil producing areas.

Cash Operating Costs and Adjusted Cash Operating Costs. We monitor cash operating costs required to produce our oil and natural gas. Cash operating costs is a non-GAAP measure calculated on a per Boe basis and includes total operating expenses less depreciation, depletion and amortization expense, transportation costs, exploration expense, natural gas purchases, impairments and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition and restructuring costs, transaction, management and other fees paid to the Sponsors (which terminated on January 23, 2014), non-cash compensation expense and costs associated with our initial public offering. We believe cash operating costs and adjusted cash operating costs per unit are valuable measures of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses for the quarters ended March 31:

	Quarters ended March 31,			
	2014		2013	
	Total	Per Unit (1)	Total	Per Unit (1)
	(in millions, except per unit costs)			
Total continuing operating expenses	$ 449	$ 52.71	$ 281	$ 37.23
Depreciation, depletion and amortization	(198)	(23.23)	(125)	(16.60)
Transportation costs	(26)	(3.01)	(22)	(2.87)
Exploration expense	(8)	(0.99)	(13)	(1.74)
Natural gas purchases	(3)	(0.41)	(2)	(0.20)
Total continuing cash operating costs	214	25.07	119	15.82
Transition/restructuring costs, non-cash compensation expense and other (2)	(100)	(11.68)	(22)	(2.90)
Total adjusted cash operating costs and adjusted per-unit cash costs(2)	$ 114	$ 13.39	$ 97	$ 12.92

Total equivalent volumes (MBoe)(3)	8,525	7,555

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

(2) Includes $90 million of transaction, management and other fees paid to our Sponsors, $9 million of non-cash compensation expense and $1 million of restructuring costs for the quarter ended March 31, 2014. Includes $3 million of transition and severance costs, $6 million of management and other fees paid to Sponsors and $13 million of non-cash compensation expense for the quarter ended March 31, 2013.

(3) Excludes volumes associated with Four Star.

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

	Quarters ended March 31, 2014		2013	
Average cash operating costs ($/Boe)				
Lease operating expenses	$	5.55	$	5.07
Production taxes(1)		3.69		2.79
General and administrative expenses(2)		15.56		7.67
Taxes, other than production and income taxes		0.27		0.29
Total cash operating costs	$	25.07	$	15.82
Transition/restructuring costs, non-cash compensation expense and other(2)	$	(11.68)	$	(2.90)
Total adjusted cash operating costs	$	13.39	$	12.92

(1) Production taxes include ad valorem and severance taxes which increased during the quarter ended March 31, 2014 primarily due to higher severance taxes associated with our oil producing areas.

(2) For additional detail of transaction, management and other fees paid to Sponsors, non-cash compensation expense and restructuring costs included in general and administrative expenses, refer to the reconciliation of cash operating costs and adjusted cash operating costs above.

Other Income Statement Items.

Loss on extinguishment of debt. For the quarter ended March 31, 2014, we recorded $17 million in losses of 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, 2014 decreased compared with the same period in 2013 due to the retirement of the PIK toggle note during January 2014 and the repayment of approximately $500 million under our term loans in August 2013.

Income taxes. For the quarter ended March 31, 2014, our effective tax rate was 36%. The effective tax rate for the first quarter of 2014 includes the effects of state income taxes and non-deductible compensation expense, substantially offset by the tax effects of discrete adjustments for certain transaction costs related to our initial public offering. We expect our annual effective tax rate to be approximately 40%. For the quarter ended March 31, 2013, we were a partnership not subject to federal and state income taxes.

Income (loss) from discontinued operations. Our income (loss) from discontinued operations for the quarter ended March 31, 2014 primarily includes a $13 million gain on the sale of certain domestic natural gas assets in the first quarter of 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), impairment charges, equity earnings from Four Star due to its sale in 2013, non-cash compensation expense, transition and restructuring costs, transaction, management and other fees paid to our Sponsors, costs associated with our initial public offering and losses 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 income (loss) from continuing operations, operating income, net cash provided by operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP.

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

	Quarters ended March 31, 2014	2013
	(in millions)	
Net loss	$ (90)	$ (114)
Income from discontinued operations, net of tax	(9)	(26)
Loss from continuing operations	(99)	(140)
Income tax benefit	(56)	
Interest expense, net of capitalized interest	79	92
Depreciation, depletion and amortization	198	125
Exploration expense	8	13
EBITDAX	130	90
Mark-to-market on financial derivatives(1)	135	131
Cash settlements and premiums on financial derivatives(2)	(25)	28
Transition and restructuring costs(3)	1	3
Income from unconsolidated affiliate(4)		(2)
Non-cash compensation expense(5)	9	13
Fees paid to Sponsors(6)	90	6
Loss on extinguishment of debt(7)	17	1
Adjusted EBITDAX	$ 357	$ 270

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

(2) Represents actual cash settlements received/(paid) related to financial derivatives, including cash premiums. For the quarters ended March 31, 2014 and 2013 we received less than $1 million and approximately $8 million, respectively, of cash premiums.

(3) Reflects transition and severance costs related to restructuring.

(4) Reflects the elimination of equity income recognized from Four Star, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets, as a result of the sale of Four Star in September 2013.

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

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

(7) Represents the loss on extinguishment of debt recorded related to retirement of the PIK toggle note in 2014 and related to the redetermination of the RBL Facility in March 2013.

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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 capacity under the RBL Facility. Our primary uses of cash are capital expenditures, debt service requirements and working capital requirements. In January 2014, we completed our initial public offering of 35.2 million shares of Class A common stock and received net proceeds of approximately $669 million. We used the proceeds to repay our PIK toggle note and a portion of our outstanding RBL Facility balance. As of March 31, 2014, our available liquidity was approximately $2.3 billion, including approximately $2.2 billion of additional borrowing capacity available under the RBL Facility. In April 2014, we completed our semi-annual redetermination maintaining the borrowing base of our RBL Facility at $2.5 billion.

We believe we have sufficient liquidity from our cash flows from operations, combined with availability under the RBL Facility and available cash, to fund our capital program, current obligations and projected working capital requirements in 2014. Our ability to (i) generate sufficient cash flows from operations or obtain future borrowings under the RBL Facility, (ii) repay or refinance any of our indebtedness on commercially reasonable terms or at all on the occurrence of certain events, such as a change of control, or (iii) obtain additional capital if required on acceptable terms or at all for any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. We have attempted to mitigate certain of these risks. For example, we enter into oil and natural gas derivative contracts to reduce the financial impact of downward commodity price movements on a substantial portion of our anticipated production. These contracts have been effective in providing greater cash flow certainty. Additionally, we occasionally enter into transactions to supplement the prices we receive through our hedging programs that involve the receipt or payment of premiums. These transactions are usually short term in nature (less than one year) and during 2014, we received less than $1 million in premiums on such transactions, all of which will settle during 2014. 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 2014, we expect our capital budget will be approximately $2 billion, substantially all of which will be expended in our core oil programs. Our capital expenditures and our average drilling rigs for the quarter ended March 31, 2014 were:

		Capital Expenditures (in millions)	**Average Drilling Rigs**
Eagle Ford Shale	$	276	6
Wolfcamp Shale		132	4
Altamont		64	4
Haynesville Shale		2	
Other		1	
Total capital expenditures	$	475	14

Long-Term Debt. As of March 31, 2014, our long-term debt is approximately $4.0 billion, comprised of $3.1 billion in senior notes due in 2019, 2020 and 2022, $645 million in senior secured term loans with maturity dates in 2018 and 2019, and $275 million outstanding under the RBL

Facility expiring in 2017. 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):

	Quarter ended March 31, 2014	Quarter ended March 31, 2013
Cash Flow from Operations		
Operating activities		
Net loss	$ (90)	$ (114)
Gain on sale of assets	(13)	
Impairment charges	3	
Other income adjustments	180	180
Change in other assets and liabilities	143	168
Total cash flow from operations	$ 223	$ 234
Other Cash Inflows		
Investing activities		
Net proceeds from the sale of assets	$ 17	$ 10
Financing activities		
Proceeds from long-term debt	550	390
Proceeds from issuance of stock	669	
	1,219	390
Total cash inflows	$ 1,236	$ 400
Cash Outflows		
Investing activities		
Capital expenditures	$ 459	$ 444
Financing activities		
Repayment of long-term debt	964	180
Debt issuance costs		3
	964	183
Total cash outflows	$ 1,423	$ 627
Net change in cash and cash equivalents	$ 36	$ 7

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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 2013 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 2013 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

The table below presents the change in fair value associated with our commodity-based price risk management activities due to hypothetical changes in prices, discount rates and credit rates at March 31, 2014:

	Oil, Natural Gas and NGLs Derivative Instruments				
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Price impact(1)	$ (6)	$ (495)	$ (489)	$ 476	$ 482

	Oil, Natural Gas and NGLs Derivative Instruments				
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
			(in millions)		
Discount rate(2)	$ (6)	$ (5)	$ 1	$ (7)	$ (1)
Credit rate(3)	$ (6)	$ (6)	$	$ (6)	$

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

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

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 2014, 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, 2014.

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 2014 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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 2013 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.

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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.

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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: May 8, 2014

/s/ Dane E. Whitehead
Dane E. Whitehead
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: May 8, 2014

/s/ Francis C. Olmsted III
Francis C. Olmsted III
Vice President and Controller
(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 * . Exhibits designated with a + constitute a management contract or compensatory plan or arrangement. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
3.1	Second Amended and Restated Certificate of Incorporation of EP Energy Corporation (Exhibit 3.1 to Company s Current Report on Form 8-K, filed with the SEC on January 23, 2014).
3.2	Amended and Restated Bylaws of EP Energy Corporation (Exhibit 3.2 to Company s Current Report on Form 8-K, filed with the SEC on January 23, 2014).
10.1+	EP Energy Corporation 2014 Omnibus Incentive Plan (Exhibit 10.1 to the Company s Current Report on Form 8-K, filed with the SEC on January 23, 2014).
*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.