EP Energy Corp
Form 10-Q
November 05, 2014

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 September 30, 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 October 30, 2014: 244,800,513

Class B Common Stock, par value $0.01 per share. Shares outstanding as of October 30, 2014: 818,909

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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)

	Quarters ended September 30, 2014	Quarters ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Operating revenues				
Oil	$ 474	$ 364	$ 1,341	$ 905
Natural gas	67	70	220	235
NGLs	31	22	88	51
Financial derivatives	381	(142)	(44)	(107)
Total operating revenues	953	314	1,605	1,084
Operating expenses				
Natural gas purchases	8	6	16	16
Transportation costs	22	23	71	65
Lease operating expense	48	36	142	107
General and administrative	33	49	208	162
Depreciation, depletion and amortization	228	164	634	417
Impairment charges	1	2	1	2
Exploration expense	5	12	18	37
Taxes, other than income taxes	35	22	102	56
Total operating expenses	380	314	1,192	862
Operating income	573		413	222
Other expense		(19)		(12)
Loss on extinguishment of debt		(6)	(17)	(9)
Interest expense	(76)	(91)	(235)	(269)
Income (loss) from continuing operations before income taxes	497	(116)	161	(68)
Income tax expense	191	30	67	30
Income (loss) from continuing operations	306	(146)	94	(98)
(Loss) income from discontinued operations, net of tax	(1)	456	3	495
Net income	$ 305	$ 310	$ 97	$ 397
Basic and diluted net income (loss) per common share				
Income (loss) from continuing operations	$ 1.25	$ (0.70)	$ 0.39	$ (0.47)
Income from discontinued operations, net of tax		2.19	0.01	2.37

Net income	$ 1.25	$ 1.49	$ 0.40	$ 1.90
Basic and diluted weighted average common shares outstanding	244	209	241	209

See accompanying notes.

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)

(Unaudited)

	September 30, 2014	December 31, 2013
ASSETS		
Current assets		
Cash and cash equivalents	$ 17	$ 51
Accounts receivable		
Customer, net of allowance of less than $1 in 2014 and 2013	255	231
Other, net of allowance of $1 in 2014 and 2013	19	40
Income tax receivable	16	3
Materials and supplies	24	20
Derivative instruments	76	47
Assets of discontinued operations		293
Deferred income taxes		28
Prepaid assets	8	10
Total current assets	415	723
Property, plant and equipment, at cost		
Oil and natural gas properties	9,761	8,136
Other property, plant and equipment	74	56
	9,835	8,192
Less accumulated depreciation, depletion and amortization	1,374	770
Total property, plant and equipment, net	8,461	7,422
Other assets		
Derivative instruments	51	97
Unamortized debt issue costs	96	116
Other	3	8
	150	221
Total assets	$ 9,026	$ 8,366

See accompanying notes.

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)

(Unaudited)

	September 30, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 173	$ 135
Other	333	386
Income tax payable		2
Deferred income taxes	12	
Derivative instruments	2	35
Accrued interest	106	54
Asset retirement obligations	2	2
Liabilities of discontinued operations		125
Other accrued liabilities	70	63
Total current liabilities	698	802
Long-term debt	4,375	4,421
Other long-term liabilities		
Deferred income taxes	192	171
Asset retirement obligations	39	28
Other	9	7
Total non-current liabilities	4,615	4,627
Commitments and contingencies (Note 8)		
Stockholders equity		
Class A shares, $0.01 par value; 550 million shares authorized; 245 million shares issued and outstanding at September 30, 2014; 209 million shares issued and outstanding at December 31, 2013	2	
Class B shares, $0.01 par value; 0.8 million and 0.9 million shares authorized, issued and outstanding at September 30, 2014 and December 31, 2013		
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding		
Additional paid-in capital	3,509	2,832
Retained earnings	202	105
Total stockholders equity	3,713	2,937
Total liabilities and equity	$ 9,026	$ 8,366

See accompanying notes.

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions)

(Unaudited)

	Nine months ended September 30, 2014	2013
Cash flows from operating activities		
Net income	$ 97	$ 397
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation, depletion and amortization	642	490
Gain on sale of assets		(455)
Deferred income tax expense	60	30
Loss from unconsolidated affiliate, net of cash distributions		37
Impairment charges	19	28
Loss on extinguishment of debt	17	9
Amortization of equity compensation expense	12	18
Non-cash portion of exploration expense	15	35
Amortization of debt issuance costs	16	16
Other	1	1
Asset and liability changes		
Accounts receivable	5	(20)
Accounts payable	(7)	68
Derivative instruments	(16)	99
Accrued interest	52	49
Other asset changes	4	(12)
Other liability changes	(11)	(3)
Net cash provided by operating activities	906	787
Cash flows from investing activities		
Capital expenditures	(1,521)	(1,420)
Proceeds from the sale of assets, net of cash transferred	126	1,439
Cash paid for acquisitions, net of cash acquired	(154)	(2)
Net cash (used in) provided by investing activities	(1,549)	17
Cash flows from financing activities		
Proceeds from long-term debt	1,835	1,310
Repayment of long-term debt	(1,895)	(1,915)
Distributions to members		(205)
Proceeds from issuance of stock	669	
Other		12
Net cash provided by (used in) financing activities	609	(798)
Change in cash and cash equivalents	(34)	6
Cash and cash equivalents		
Beginning of period	51	69
End of period	$ 17	$ 75

See accompanying notes

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EP ENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(In millions)

(Unaudited)

	Stockholders Equity							
	Class A Stock		Class B Stock		Additional Paid-in	Retained	
	Shares	Amount	Shares	Amount	Capital	Earnings	Total
Balance at December 31, 2013	209	$	0.9	$	$ 2,832	$ 105	$ 2,937
Share-based compensation	1		(0.1)		10		10
Initial public offering of common stock	35	2			667		669
Net income						97	97
Balance at September 30, 2014	245	$ 2	0.8	$	$ 3,509	$ 202	$ 3,713

See accompanying notes.

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 condensed consolidated financial statements. Because this is an interim period report presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP and should be read along with our 2013 Annual Report on Form 10-K. The condensed consolidated financial statements as of September 30, 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. 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 2013 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.

Revenue Recognition. In May 2014, the Financial Accounting Standards Board (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. We are currently evaluating the impact, if any, that this standard will have on our financial statements.

Discontinued Operations. In April 2014, the 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. The new standard will (i) raise the threshold for divestitures to qualify as discontinued operations and (ii) require new disclosures for both discontinued operations and material divestitures which do not qualify as discontinued operations.

2. Acquisitions and Divestitures

Acquisitions. On April 30, 2014, we acquired 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 approximately $152 million. The acquisition represents an approximate 25% expansion of our current Wolfcamp acreage. The fair value of the business acquired was allocated to the underlying properties and no goodwill or bargain purchase was recorded.

Discontinued Operations. We have reflected as discontinued operations certain non-core assets sold including (i) certain domestic natural gas assets in our Arklatex area and those in our South Louisiana Wilcox areas sold in May 2014, (ii) domestic natural gas assets closed in June 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 (iii) our Brazilian operations closed in August 2014.

We have classified the assets and liabilities associated with these properties as discontinued operations in our condensed consolidated balance sheets in this Form 10-Q in periods prior to the completion of the sale. We have classified the results of operations of these assets as income (loss) from discontinued operations in all periods presented.

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

	Quarters ended September 30, 2014	Quarters ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Operating revenues	$ 14	$ 66	$ 82	$ 314
Operating expenses				
Natural gas purchases		2		18
Transportation costs		3	5	22
Lease operating expense	6	23	31	84
Depreciation, depletion and amortization		8	8	73
Impairment charges(1)	3	18	18	28
Other expense	4	11	17	45
Total operating expenses	13	65	79	270
(Loss) gain on sale of assets	(1)	455		455
Other (expense) income	(1)	2	4	
(Loss) income from discontinued operations before income taxes	(1)	458	7	499
Income tax expense		2	4	4
(Loss) income from discontinued operations, net of tax	$ (1)	$ 456	$ 3	$ 495

(1) During the quarter and nine months ended September 30, 2014, we recorded $3 million and $18 million in impairment charges to impair earnings subsequent to entering into a Quota Purchase Agreement to sell our Brazil operations. During the quarter and nine months ended September 30, 2013, we recorded $18 million and $28 million in impairment charges ($18 million to impair earnings subsequent to entering into the Quota Purchase Agreement and $10 million based on a comparison of the fair value of our Brazil operations to its underlying carrying value).

	December 31, 2013
Assets of discontinued operations	
Current assets	$ 37
Property, plant and equipment, net	246
Other non-current assets	10
Total assets of discontinued operations	$ 293
Liabilities of discontinued operations	
Accounts payable	$ 50
Other current liabilities	10
Asset retirement obligations	60
Other non-current liabilities	5
Total liabilities of discontinued operations	$ 125

Other Divestitures. During the third quarter of 2013, we sold our approximate 49% equity interest in Four Star Oil & Gas Company (Four Star) for proceeds of approximately $183 million. In connection with entering into the sale we recorded an impairment in earnings from unconsolidated affiliates. See Note 10 for further discussion. 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 the sale.

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 currently not under any U.S. or state income tax audits and we have no uncertain tax positions from our continuing operations.

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.

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For the quarter and nine months ended September 30, 2014, we recorded an income tax expense of $191 million and $67 million, respectively. Our effective tax rates for the quarter and nine months ended September 30, 2014, were 38% and 42%, respectively, which differ from the statutory federal tax rate of 35% as a result of the effects of state income taxes, non-deductible compensation expense, and discrete adjustments for certain transaction costs related to our initial public offering. The effective tax rate for the quarter and nine months ended September 30, 2013, were (26%) and (44%), significantly lower than the statutory rate primarily due to only recording income tax expense subsequent to the Corporate Reorganization on August 30, 2013 and the level of pretax income during the period. If we had recorded income taxes effective January 1, 2013, through September 30, 2013, pro forma loss from continuing operations would have been approximately $45 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 and nine months ended September 30, 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. 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. These potentially dilutive securities consist of our employee stock options and restricted stock which did not affect diluted earnings per share for the quarter and nine months ended September 30, 2014.

5. Financial Instruments

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

	September 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
		(in millions)		
Long-term debt	$ 4,375	$ 4,587	$ 4,421	$ 4,841
Derivative instruments	$ 125	$ 125	$ 109	$ 109

As of September 30, 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 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, natural gas and NGLs through the use of financial derivatives. As of September 30, 2014 and December 31, 2013, we had total derivative contracts on 44 MMBbls and 47 MMBbls of oil and 87 TBtu and 135 TBtu of natural gas, respectively. As of September 30, 2014, we also had derivative contracts on 12 MMGal of propane. None of these contracts are designated as accounting hedges.

Between October 1, 2014 and November 5, 2014, we exchanged 4.0 MMBbls of Brent fixed price swaps on our anticipated 2016 production for basis swap positions. The following table reflects the volumes exchanged on our derivative instruments.

	2015 Volumes	**2016 Volumes**
Oil (MBbls)		
Basis Swaps		
LLS vs. WTI	1,095	
LLS vs. Brent		2,196
Midland vs. Cushing	730	

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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 September 30, 2014 and December 31, 2013, we had a net asset of $4 million, respectively, related to interest rate derivative instruments included in our consolidated balance sheets. For the quarters ended September 30, 2014 and 2013, we recorded $2 million of interest income and $4 million of interest expense related to the change in fair market value and cash settlements of our interest rate derivative instruments, respectively. For the nine months ended September 30, 2014 and 2013, we recorded $3 million in interest expense and $3 million in interest income, 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 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 September 30, 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.

Financial Statement Presentation. The following table presents the fair value associated with derivative financial instruments as of September 30, 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)			
September 30, 2014								
Derivative instruments	$ 150	$ (23)	$ 76	$ 51	$ (25)	$ 23	$ (2)	$
December 31, 2013								
Derivative instruments	$ 164	$ (20)	$ 47	$ 97	$ (55)	$ 20	$ (35)	$

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(1) Gross derivative assets are comprised primarily of $143 million of oil, natural gas and NGLs derivatives as of September 30, 2014, $157 million of oil and natural gas derivatives as of December 31, 2013, and $7 million of interest rate derivatives as of both periods September 30, 2014 and December 31, 2013. Gross derivative liabilities are comprised primarily of $22 million of oil, natural gas and NGLs derivatives as of September 30, 2014, $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 September 30, 2014 and December 31, 2013.

For the quarters ended September 30, 2014 and 2013, we recorded a derivative gain of $381 million and a derivative loss of $142 million, respectively, on our oil, natural gas and NGLs financial derivative instruments. For the nine months ended September 30, 2014 and 2013, we recorded derivative losses of $44 million and $107 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statement.

6. Property, Plant and Equipment

General. As of September 30, 2014 and December 31, 2013, we had $1.0 billion and $1.4 billion of unproved oil and natural gas properties on our consolidated balance sheet, respectively. During the nine months ended September 30, 2014, we transferred approximately $0.5 billion from unproved properties to proved properties. For the quarters ended September 30, 2014 and 2013, we recorded $4 million and $9 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. For the nine months ended September 30, 2014 and 2013, we recorded $15 million and $33 million of amortization of unproved leasehold costs in exploration expense in our consolidated income statement. Suspended well costs were not material as of September 30, 2014 or December 31, 2013. For a discussion of our impairment assessment of oil and natural gas properties see Note 3 to our 2013 Annual Report on Form 10-K.

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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 September 30, 2014 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability from January 1 through September 30, 2014 were as follows:

		2014 (in millions)
Net asset retirement liability at January 1	$	30
Liabilities incurred		9
Liabilities settled		(1)
Accretion expense		2
Changes in estimate		2
Other		(1)
Net asset retirement liability at September 30	$	41

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. Capitalized interest for the quarter and nine months ended September 30, 2014 was approximately $6 million and $16 million, respectively. Capitalized interest for the quarter and nine months ended September 30, 2013 was approximately $6 million and $14 million, respectively.

7. Long-Term Debt

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

	Interest Rate		September 30, 2014 (in millions)
$2.5 billion RBL credit facility - due May 24, 2017	Variable	$	630
$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		$	4,375

(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 September 30, 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 September 30, 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 September 30, 2014 and December 31, 2013, we had $96 million and $116 million, respectively, in deferred financing costs on our consolidated balance sheets. During the quarters ended September 30, 2014 and 2013, we amortized $5 million and $6 million, respectively, of deferred financing costs in interest expense. For each of the nine months ended September 30, 2014 and 2013, we amortized $16 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. During the quarter ended September 30, 2013 and each of the nine month periods ended September 30, 2014 and 2013, we recorded $6 million, $17 million and $9 million, respectively, in losses on the extinguishment of debt in our consolidated income statement. In 2014, these losses resulted from the retirement of the PIK toggle note. In 2013, the losses were associated with the pro-rata portion of deferred financing costs written off in conjunction with (i) the repayment of approximately $250 million under each of our $750 million and $400 million term loans, (ii) our $750 million term loan repricing in May 2013 and (iii) 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 September 30, 2014, we had a $2.5 billion RBL borrowing base, $630 million of outstanding borrowings and approximately $21 million of letters of credit issued under the facility, leaving $1.8 billion of remaining capacity. As of November 4, 2014, we had $865 million in outstanding borrowings under the facility.

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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 October 2014, we completed our semi-annual redetermination, increasing the borrowing base of our RBL Facility to $2.75 billion. Our next redetermination date is in April 2015. 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 September 30, 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 September 30, 2014, 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 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 has passed 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 September 30, 2014, we had approximately $9 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 September 30, 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 $1 million. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts that we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

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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. 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. In July 2014, EPA proposed additional amendments to the new standard for which we would not anticipate material capital expenditure, if the amendments as proposed become final.

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.

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 September 30, 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.

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9. Long-Term Incentive Compensation

Our long-term incentive (LTI) awards currently include a cash-based incentive award and certain equity-based compensation programs, as further described in our 2013 Annual Report on Form 10-K. During the nine months ended September 30, 2014, we issued 1,054,444 shares of restricted common stock (net of shares forfeited) and granted 253,740 stock options as compensation for future service. Under our stock-based compensation plans, we are authorized to grant awards of up to 12,433,749 shares of our common stock. The restricted stock granted had an average grant date fair value of $19.85 per share equal to the market value of our stock on the grant date, and stock options issued had an average grant date fair value of $9.03 per option granted. The fair value of each stock option granted was estimated on the date of grant using a Black-Scholes option-pricing model based on several assumptions utilizing management s best estimate at the time of grant. These assumptions included an expected term of 7 years, volatility of approximately 40%, a risk free rate of approximately 2.3 percent, and assumed no dividend yield. We estimated expected volatility based on an analysis of historical stock price volatility of a group of similar publicly traded peer companies which share similar characteristics with us over the expected term because our stock has been publicly traded for a very short period of time. We estimate the expected term of our option awards based on the vesting period and average remaining contractual term, and use this method to provide a reasonable basis for estimating our expected term based on insufficient historical data prior to 2014.

Restricted stock grants carry voting and dividend rights, vest ratably over a three-year period for a substantial portion of the awards granted, and may not be sold or transferred until they are vested. Stock options granted have contractual terms of 10 years and vest in three tranches over a five-year period (with the first tranche vesting on the third anniversary of the grant date, the second tranche vesting on the fourth anniversary of the grant date and the third tranche vesting on the fifth anniversary thereof), but commence vesting earlier in the event of a complete sell-down by certain of our private equity investors of their shares of our common stock. We do not pay dividends on unexercised options. We record stock-based compensation expense on our restricted stock and stock option grants as general and administrative expense over the requisite service period on a straight-line basis, net of estimates of forfeitures. If actual forfeitures differ from our estimates, additional adjustments to compensation expense will be required in future periods.

Compensation expense (recorded as general and administrative expense on our income statement) related to all of our long-term incentive awards (both cash-based and equity-based) was approximately $2 million and $19 million during the quarter and nine months ended September 30, 2014, respectively, and approximately $8 million and $32 million during the quarter and nine months ended September 30, 2013. During the nine months ended September 30, 2014 and 2013, we paid approximately $13 million and $10 million, respectively, under our long-term incentive programs. As of September 30, 2014, we had unrecognized compensation expense of $54 million. We will recognize an additional $5 million related to outstanding awards as of September 30, 2014 during the rest of 2014, $32 million over the remaining requisite service periods subsequent to 2014 and $17 million upon a specified capital transaction when the right to such amounts become non-forfeitable.

10. Investment in Unconsolidated Affiliate

As discussed in Note 2, in September 2013, we sold our equity investment in Four Star for net proceeds of $183 million and recorded an impairment of $20 million based on comparison of net proceeds received to the underlying carrying value of our investment. For the quarter and nine months ended September 30, 2013, we also recorded $3 million and $15 million for our share of net equity earnings directly attributable to Four Star and $2 million and $8 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. Our financial results related to our equity investment in Four Star were included as other expense on our income statements. Total operating revenues, operating expenses and net income of Four Star for the quarter ended September 30, 2013 were $40 million, $27 million, and $8 million, respectively. Total operating revenues, operating expenses and net income of Four Star for the nine months ended September 30, 2013 were $142 million, $94 million, and $30 million, respectively. For the quarter and nine months ended September 30, 2013, we received dividends from Four Star of approximately $7 million and $24 million, respectively.

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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 Management LLC (Apollo), 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. We recorded both of these fees in general and administrative expense. 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. For the nine months ended September 30, 2014, we have recorded approximately $82 million in capital expenditures for amounts provided under a supply agreement entered into with an Apollo affiliate in November 2012 (with the current term extending through October 2016) to provide certain fracturing materials for our Eagle Ford drilling operations.

Member Distribution. In 2013, we made $205 million in distributions to our members including a leveraged distribution of approximately $200 million.

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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 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 currently are running five 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 field. Most of our acreage in this area is held-by-production. We 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 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.

On April 30, 2014, we acquired 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 $152 million. The acquisition represents an approximate 25% expansion of our current Wolfcamp acreage. We are integrating the acquired properties into our existing development program with minimal additional capital in 2014.

On May 30, 2014, we completed the sale of certain non-core assets in our Arklatex area and those in our South Louisiana Wilcox area (approximately 78,000 net acres) for $150 million of cash proceeds, with the buyer also assuming a transportation commitment of approximately $20 million. We recorded a $10 million loss on the sale. Net estimated annual production associated with the divested properties is approximately 21 MMcfe/d, approximately 85% of which is natural gas. Additionally, on August 29, 2014, we closed the sale of our Brazilian operations. No gain or loss was recorded upon the sale.

We have reflected as discontinued operations in all periods presented certain non-core assets sold including (i) certain domestic natural gas assets in our Arklatex area and those in our South Louisiana Wilcox areas sold in May 2014, (ii) domestic natural gas assets closed in June 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 (iii) our Brazilian operations closed in August 2014.

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Factors Influencing Our Profitability. Our profitability is dependent on the prices we receive for our oil, natural gas and NGLs, the costs to explore, develop, and produce our oil, natural gas and NGLs, 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.

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 nine months ended September 30, 2014, we (i) settled commodity index hedges on approximately 86% of our liquids (oil and NGLs) production and 100% of our natural gas production at average floor prices of $97.90 per barrel of oil and $4.02 per MMBtu, respectively and (ii) hedged basis risk on approximately 58% of our year-to-date Eagle Ford oil production. To the extent our oil, natural gas, and NGLs 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 September 30, 2014.

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	2014			2015			2016		
	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)	Volumes(1)		Average Price(1)
Oil									
Fixed Price Swaps									
WTI	3,215	$	97.06	17,373	$	89.34	5,216	$	85.25
Brent	920	$	102.47	2,555	$	100.01	4,026	$	95.01
LLS	598	$	99.25		$		6,222	$	92.22
Ceilings	429	$	100.93	1,095	$	100.00		$	
Three Way Collars									
Ceiling - WTI	230	$	104.04		$			$	
Floors - WTI(2)	230	$	95.00		$			$	
Ceiling - Brent		$		1,095	$	110.02		$	
Floors - Brent(3)		$		1,095	$	100.00		$	
Ceiling - LLS		$			$		1,464	$	99.29
Floors - LLS(4)		$			$		1,464	$	94.00
Basis Swaps									
LLS vs. WTI(5)(7)	736	$	5.78	2,190	$	2.80	183	$	3.00
LLS vs. Brent(6)(7)	920	$	(3.72)	3,650	$	(3.77)	1,830	$	(1.89)
Midland vs. Cushing(8)	184	$	(1.20)		$			$	
Natural Gas									
Fixed Price Swaps	17	$	4.02	62	$	4.26	7	$	4.20
Basis Swaps(9)									
TGP vs. Henry Hub		$		1	$	(0.10)		$	
CIG vs. Henry Hub		$		4	$	(0.25)		$	
Waha vs. Henry Hub		$		4	$	(0.07)		$	
NGLs									
Propane Fixed Price Swaps	8	$	1.14		$			$	
Propane Collars									
Ceilings	4	$	1.30		$			$	
Floors	4	$	1.00		$			$	

(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 $75.00 in 2014, we will receive a locked-in cash settlement of the market price plus $20.00 per Bbl.

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

(4) 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.

(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) We have effective LLS floor prices on future hedged production of $100.22 per Bbl for 2014, $94.70 per Bbl for 2015 and $92.58 per Bbl for 2016. These floors are derived using a combination of fixed price positions and basis positions and do not include any customary refinery or contractual deductions.

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

(9) EP Energy receives Henry Hub less basis spread listed and pays TGP, CIG and Waha.

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). During 2014, we received approximately $1 million in premiums on such transactions, all of which settle during 2014.

Between October 1, 2014 and November 5, 2014, we exchanged 4.0 MMBbls of Brent fixed price swaps on our anticipated 2016 production with an average price of $95.01 per Bbl for basis swap positions. The following table reflects the volumes and the prices exchanged on our derivative instruments.

	2015		2016	
	Volumes(1)	**Average Price(1)**	**Volumes(1)**	**Average Price(1)**
Oil				
Basis Swaps				
LLS vs. WTI(2)	1,095	$ 7.25		$
LLS vs. Brent(3)		$	2,196	$ (4.99)
Midland vs. Cushing(4)	730	$		$

(1) Volumes presented are MBbls for oil. Prices presented are per Bbl of oil.

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

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

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

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Summary of Liquidity and Capital Resources. As of September 30, 2014, we had available liquidity, including existing cash, of approximately $1.9 billion. We believe we have sufficient liquidity for 2014 from our cash flows from operations, combined with the availability under our RBL Facility ($2.1 billion after increasing the borrowing base in October 2014 to $2.75 billion) and available cash, to fund our current obligations, projected working capital requirements and capital spending plan in 2014 and the foreseeable future. Additionally, the earliest maturity date of our debt obligations is in 2017. Finally, given recent declines in oil prices, we believe our oil and natural gas hedge positions covering the remainder of 2014, and 2015 and 2016 also provide significant price protection to our near-term revenues and cash flows. See Liquidity and Capital Resources for more information.

Outlook for 2014. For the full year 2014, in line with guidance announced in the second quarter we expect the following:

- Capital expenditures of approximately $2 billion, allocated entirely to our core oil programs: $1 billion for Eagle Ford, $725 million for Wolfcamp, $250 million for Altamont, and additional acquisition capital of approximately $154 million.

- Well completions between 270 and 280.

- Average daily production volumes for the year of approximately 96 MBoe/d to 100 MBoe/d, including average daily oil production volumes of approximately 54 MBbls/d to 56 MBbls/d.

- Per unit adjusted cash operating costs for the year of approximately $12.90 to $13.90 per Boe, and transportation costs of $3.00 to $3.25 per Boe.

- Per unit depreciation, depletion and amortization rate for the year of approximately $24.35 to $25.35 per Boe.

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Production Volumes and Drilling Summary

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

	2014	2013
United States (MBoe/d)		
Eagle Ford Shale	50	36
Wolfcamp Shale	14	5
Altamont	15	11
Haynesville Shale	17	29
Other(1)		8
Total	96	89
Oil (MBbls/d)(1)	53	35
Natural Gas (MMcf/d)(1)	193	278
NGLs (MBbls/d)(1)	11	7

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(1) 2013 includes volumes of Four Star Oil & Gas Company (Four Star), our equity investment sold in September 2013. For the nine months ended September 30, 2013, Four Star s production volumes were 1 MBbls/d of oil, 37 MMcf/d of natural gas and 1 MBbls/d of NGLs.

- *Eagle Ford Shale* Our Eagle Ford Shale equivalent volumes and oil production increased 14 MBoe/d (39%) and 11 MBbls/d (48%), respectively, for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 due to the success of our drilling program in the area. During the nine months ended September 30, 2014, we completed 93 additional operated wells in the Eagle Ford, and we had a total of 359 net operated wells as of September 30, 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 9 MBoe/d (180%) for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013 as we continue to progress the development of the program. During the nine months ended September 30, 2014, we completed 69 additional operated wells, and as of September 30, 2014 we had a total of 180 net operated wells (which includes wells acquired in April 2014).

- *Altamont* Our Altamont equivalent volumes increased 4 MBoe/d (36%) for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013. Altamont produced an average of 11 MBbls/d of oil during the nine months ended September 30, 2014, and we completed 36 additional operated oil wells for a total of 345 net operated wells at September 30, 2014. In October 2014, the Utah Board of Oil, Gas and Mining provisionally approved 80 acre well density on approximately 50,000 of our Altamont net acreage.

- *Haynesville Shale* Our Haynesville Shale equivalent volumes decreased 72 MMcfe/d (41%) for the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013, due to natural production declines. Our Haynesville drilling program remains suspended based on current natural gas prices. As of September 30, 2014, we had 99 net operated wells in the Haynesville Shale, and our total natural gas production for the nine months ended September 30, 2014 was approximately 99 MMcf/d.

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Results of Operations

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

	Quarters ended September 30, 2014	Quarters ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
	(in millions)			
Operating revenues				
Oil	$ 474	$ 364	$ 1,341	$ 905
Natural gas	67	70	220	235
NGLs	31	22	88	51
Total physical sales	572	456	1,649	1,191
Financial derivatives	381	(142)	(44)	(107)
Total operating revenues	953	314	1,605	1,084
Operating expenses				
Natural gas purchases	8	6	16	16
Transportation costs	22	23	71	65
Lease operating expense	48	36	142	107
General and administrative	33	49	208	162
Depreciation, depletion and amortization	228	164	634	417
Impairment charges	1	2	1	2
Exploration expense	5	12	18	37
Taxes, other than income taxes	35	22	102	56
Total operating expenses	380	314	1,192	862
Operating income	573		413	222
Other expense		(19)		(12)
Loss on extinguishment of debt		(6)	(17)	(9)
Interest expense	(76)	(91)	(235)	(269)
Income (loss) from continuing operations before income taxes	497	(116)	161	(68)
Income tax expense	191	30	67	30
Income (loss) from continuing operations	306	(146)	94	(98)
(Loss) income from discontinued operations, net of tax	(1)	456	3	495
Net income	$ 305	$ 310	$ 97	$ 397

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarter and nine months ended September 30, 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.

	Quarters ended September 30,		Nine months ended September 30,	
	2014	**2013**	**2014**	**2013**
		(in millions)		
Operating revenues:				
Oil	$ 474	$ 364	$ 1,341	$ 905
Natural gas	67	70	220	235
NGLs	31	22	88	51
Total physical sales	572	456	1,649	1,191
Financial derivatives	381	(142)	(44)	(107)
Total operating revenues	$ 953	$ 314	$ 1,605	$ 1,084
Volumes:				
Oil (MBbls)(1)	5,260	3,681	14,481	9,537
Natural gas (MMcf)(1)	17,572	22,934	52,700	75,713
NGLs (MBbls)(1)	1,098	778	2,992	2,049
Equivalent volumes (MBoe)(1)	9,286	8,281	26,256	24,204
Total MBoe/d	101	90	96	89
Prices per unit(2):				
Oil				
Average realized price on physical sales ($/Bbl)(3)	$ 90.19	$ 100.64	$ 92.61	$ 96.87
Average realized price, including financial derivatives ($/Bbl)(3)(4)	$ 89.65	$ 94.80	$ 90.49	$ 98.75
Natural gas				
Average realized price on physical sales ($/Mcf)(3)	$ 3.32	$ 3.19	$ 3.87	$ 3.33
Average realized price, including financial derivatives ($/Mcf)(4)	$ 3.27	$ 2.95	$ 3.30	$ 3.03
NGLs				
Average realized price on physical sales ($/Bbl)	$ 28.56	$ 31.23	$ 29.39	$ 29.46
Average realized price, including financial derivatives ($/Bbl)(4)	$ 29.24	$	$ 29.57	$

(1) In September 2013, we sold our equity investment in Four Star. For the quarter and nine months ended September 30, 2013, Four Star s production volumes were 62 MBbls and 198 MBbls of oil, 2,684 MMcf and 10,001 MMcf of natural gas, 98 MBbls and 328 MBbls of NGLs and 607 MBoe and 2,192 MBoe of equivalent volumes, respectively.

(2) Natural gas prices for the quarter and nine months ended September 30, 2014 are calculated including a reduction of $8 million and $16 million, respectively, for natural gas purchases associated with managing our physical gas sales. Natural gas prices for the quarter and nine months ended September 30, 2013 are calculated including a reduction of $6 million and $16 million, respectively, for natural gas purchases associated with managing our physical gas sales. Prices per unit are based on consolidated volumes and do not include volumes associated with Four Star which was sold in September 2013.

(3) Changes in realized oil and natural gas prices reflect 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 and natural gas.

(4) The quarters ended September 30, 2014 and 2013, include approximately $3 million and $21 million of cash paid, respectively, for the settlement of crude oil derivative contracts and approximately $1 million and $5 million of cash paid, respectively, for the settlement of natural gas financial derivatives. The nine months ended September 30, 2014 and 2013, include approximately $31 million of cash paid and approximately $10 million of cash receipts, respectively, for the settlement of crude oil derivative contracts and approximately $30 million and $20 million of cash paid, respectively, for the settlement of natural gas financial derivatives. For the quarter and nine months ended September 30, 2014, we received approximately $1 million and less than $1 million for the settlement of NGLs derivative contracts. No cash premiums were received for the quarter ended September 30, 2014. Cash premiums received for the quarter ended September 30, 2013 were approximately $1 million and for the nine months ended September 30, 2014 and 2013 were approximately $1 million and approximately $9 million.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter and nine months ended September 30, 2014, physical sales increased by $116 million (25%) and $458 million (38%), respectively, compared to the same periods in 2013 largely attributable to period-over-period increases in oil volumes. The table below displays the price and volume variances on our physical sales when comparing the quarters and nine months ended September 30, 2014 and 2013.

	Quarter ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
September 30, 2013 sales	$ 364	$ 70	$ 22	$ 456
Change due to prices	(55)	6	(4)	(53)
Change due to volumes	165	(9)	13	169
September 30, 2014 sales	$ 474	$ 67	$ 31	$ 572

	Nine months ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
September 30, 2013 sales	$ 905	$ 235	$ 51	$ 1,191
Change due to prices	(62)	31		(31)
Change due to volumes	498	(46)	37	489
September 30, 2014 sales	$ 1,341	$ 220	$ 88	$ 1,649

Oil sales for the quarter and nine months ended September 30, 2014 compared to the same periods in 2013 increased by $110 million (30%) and $436 million (48%), respectively, due primarily to oil volume growth from our Eagle Ford, Wolfcamp and Altamont drilling programs. For the quarter and nine months ended September 30, 2014 compared to the same periods in 2013, Eagle Ford oil production increased by 38% (10 MBbls/d) and 47% (11 MBbls/d), respectively, Wolfcamp oil production increased by 117% (5 MBbls/d) and 178% (5 MBbls/d), respectively, and Altamont oil production volumes increased by 33% (3 MBbls/d) and 33% (3 MBbls/d), respectively.

Natural gas sales decreased for the quarter and nine months ended September 30, 2014 compared to the same periods in 2013 primarily due to a decrease in volumes due to natural production declines in the Haynesville Shale partially offset by higher natural gas prices. Our Haynesville drilling program remains suspended based on current natural gas prices.

Our oil and natural gas is typically sold at index prices (NYMEX, LLS, WTI or 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 in a largely LLS-based market. 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 September 30,			
	2014		2013	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$ (7.18)	$ (0.60)	$ (5.21)	$ (0.36)
NYMEX	$ 97.17	$ 4.06	$ 105.83	$ 3.58

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	Nine months ended September 30,							
	2014				2013			
	Oil (Bbl)		Natural gas (MMBtu)		Oil (Bbl)		Natural gas (MMBtu)	
	(in millions)							
Differentials and deducts	$	(6.98)	$	(0.61)	$	(1.37)	$	(0.34)
NYMEX	$	99.61	$	4.55	$	98.14	$	3.67

The larger differentials and deducts in the quarter and nine months ended September 30, 2014 were generally a result of wider basis differentials in areas currently facing oversupply due to a combination of temporary refinery outages and insufficient takeaway capacity along with slightly higher market prices.

NGLs sales increased for the quarter and nine months ended September 30, 2014 compared to the same periods in 2013 due to higher volumes as a result of our Eagle Ford and Wolfcamp drilling programs. For the quarter and nine months ended September 30, 2014 compared to the same periods in 2013, Eagle Ford NGLs volumes increased by 15% (1 MBbls/d) and 35% (2 MBbls/d), respectively, and Wolfcamp NGLs volumes increased by 603% (4 MBbls/d) and 472% (3 MBbls/d), respectively.

As of September 30, 2014, the NYMEX spot price of a barrel of oil was $91.16 versus the NYMEX spot price of natural gas of $4.12, or a ratio of 22 to 1. We have and will continue to target increases in our oil volumes due to this value difference. Growth in our physical revenue will largely be impacted by our ability to grow our oil volumes. Our overall oil sales (including the impact of financial derivatives) are also impacted by changes in oil prices to the extent our production is not hedged. Based on our current hedging program, if we experienced a $10 per barrel reduction in index prices on oil sold during the third quarter ended September 30, 2014, our total revenues would have only decreased by approximately $5 million.

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 September 30, 2014, we recorded $381 million of derivative gains compared to derivative losses of $142 million during the quarter ended September 30, 2013. For the nine months ended September 30, 2014, we recorded $44 million of derivative losses compared to derivative losses of $107 million for the nine months ended September 30, 2013.

Operating Expenses

Transportation costs. Transportation costs for the quarter and nine months ended September 30, 2014 were $22 million and $71 million, respectively, compared to $23 million and $65 million for the same periods in 2013. Total transportation costs have increased for the nine months ended September 30, 2014 primarily due to oil and NGLs transportation costs associated with Eagle Ford and Wolfcamp as a result of our production growth and new contracts in these areas.

Lease operating expense. Lease operating expense for the quarter and nine months ended September 30, 2014 were $48 million and $142 million, respectively, compared to $36 million and $107 million for the same periods in 2013. Total lease operating expense has increased in 2014 due to higher chemical, maintenance, disposal, repair and power costs in Eagle Ford and higher chemical, 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 September 30, 2014 decreased by $16 million and increased by $46 million for the nine months ended September 30, 2014 compared to the same periods in 2013. Both the third quarter and nine months in 2014 reflect an $11 million reduction in general and administrative expenses associated with an insurance settlement, and lower payroll, benefits and administrative costs of $7 million and $22 million, for the quarter and nine months ended September 30, 2014 compared to the same periods in 2013. Also affecting 2014 were (i) advisory fees paid in January 2014 to our Sponsors of $6.25 million compared to $19 million paid in 2013, and (ii) 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.

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Depreciation, depletion and amortization expense. Our depreciation, depletion and amortization costs increased in 2014 compared to the same periods in 2013 due to an increase in production volumes and 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 this ongoing development of our higher cost liquids programs. Our average depreciation, depletion and amortization costs per unit for the quarters and nine months ended September 30 were:

	Quarters ended September 30, 2014	Quarters ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
Depreciation, depletion and amortization ($/Boe)(1)	$ 24.56	$ 21.36	$ 24.14	$ 18.93

(1) Includes $0.07 per Boe for both the quarters ended September 30, 2014 and 2013 and $0.07 per Boe for both the nine months ended September 30, 2014 and 2013 related to accretion expense on asset retirement obligations.

Exploration expense. For the quarter and nine months ended September 30, 2014, we recorded $5 million and $18 million of exploration expense compared to $12 million and $37 million for the same periods in 2013. Included in exploration expense for the quarter and nine months ended September 30, 2014 is $4 million and $15 million of amortization of unproved property costs compared to $9 million and $33 million for the same periods in 2013.

Taxes, other than income taxes. Taxes, other than income taxes for the quarter and nine months ended September 30, 2014 were $35 million and $102 million, respectively, compared to $22 million and $56 million for the same periods in 2013. Production taxes increased in 2014 compared to the same periods in 2013 due to higher severance taxes associated with growing production volumes in our oil producing areas. Additionally, year-to-date production taxes in 2013 reflect a reduction in sales and use tax of $13 million recorded in the second quarter of 2013 associated with settling a sales and use tax matter.

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, impairment charges and other expenses. Adjusted cash operating costs is a non-GAAP measure and is defined as cash operating costs less transition, restructuring and other non-recurring costs, management and other fees paid to the Sponsors (which terminated on January 23, 2014), and the non-cash portion of compensation expense (which represents compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans). We believe cash operating costs and adjusted cash operating costs per unit are valuable measures of operating performance and efficiency; however, these measures may not be comparable to similarly titled measures used by other companies. The table below represents a reconciliation of our cash operating costs and adjusted cash operating costs to operating expenses for the quarters and nine months ended September 30:

	Quarters ended September 30, 2014 Total	2014 Per Unit(1)	2013 Total	2013 Per Unit(1)
	(in millions, except per unit costs)			
Total continuing operating expenses	$ 380	$ 40.94	$ 314	$ 41.05

Depreciation, depletion and amortization		(228)		(24.56)		(164)		(21.36)
Transportation costs		(22)		(2.42)		(23)		(2.94)
Exploration expense		(5)		(0.54)		(12)		(1.49)
Natural gas purchases		(8)		(0.92)		(6)		(0.85)
Impairment charges		(1)		(0.07)		(2)		(0.24)
Total continuing cash operating costs		116		12.43		107		14.17
Transition/restructuring costs, non-cash portion of compensation expense and other(2)		3		0.42		(14)		(1.95)
Total adjusted cash operating costs and adjusted per-unit cash costs(2)	$	119	$	12.85	$	93	$	12.22
Total equivalent volumes (MBoe)(3)		9,286				7,674		

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	Nine months ended September 30,			
	2014		2013	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Total continuing operating expenses	$ 1,192	$ 45.40	$ 862	$ 39.19
Depreciation, depletion and amortization	(634)	(24.14)	(417)	(18.93)
Transportation costs	(71)	(2.72)	(65)	(2.94)
Exploration expense	(18)	(0.68)	(37)	(1.67)
Natural gas purchases	(16)	(0.62)	(16)	(0.75)
Impairment charges	(1)	(0.02)	(2)	(0.08)
Total continuing cash operating costs	452	17.22	325	14.82
Transition/restructuring costs, non-cash portion of compensation expense and other(2)	(92)	(3.49)	(48)	(2.18)
Total adjusted cash operating costs and adjusted per-unit cash costs(2)	$ 360	$ 13.73	$ 277	$ 12.64
Total equivalent volumes (MBoe)(3)	26,256		22,012	

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

(2) 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. For the quarter ended September 30, 2014 amount includes $11 million of cash received from an insurance settlement, $5 million of acquisition costs and $2 million of non-cash compensation expense. For the nine months ended September 30, 2014 amount includes $90 million of transaction, management and other fees paid to our Sponsors, $11 million of cash received from an insurance settlement, $5 million of acquisition costs and $6 million of non-cash compensation expense as well as transition and severance costs related to restructuring. For the quarter ended September 30, 2013 amount includes $6 million of management and other fees paid to our Sponsors and $8 million of non-cash compensation expense. For the nine months ended September 30, 2013 amount includes $7 million of transition and severance costs, $19 million of management and other fees paid to our Sponsors and $22 million of non-cash compensation expense adjusted for cash payments of approximately $10 million.

(3) Excludes volumes associated with our equity investment in Four Star sold in September 2013.

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

	Quarters ended September 30,		Nine months ended September 30,	
	2014	2013	2014	2013
Average cash operating costs ($/Boe)				
Lease operating expenses	$ 5.12	$ 4.75	$ 5.41	$ 4.88
Production taxes(1)	3.60	2.81	3.64	2.89
General and administrative expenses(2)	3.52	6.41	7.93	7.37
Taxes, other than production and income taxes(3)	0.19	0.20	0.24	(0.32)
Total cash operating costs	$ 12.43	$ 14.17	$ 17.22	$ 14.82
Transition/restructuring costs, non-cash portion of compensation expense and other(2)	$ 0.42	$ (1.95)	$ (3.49)	$ (2.18)
Total adjusted cash operating costs	$ 12.85	$ 12.22	$ 13.73	$ 12.64

(1) Production taxes include ad valorem and severance taxes which increased during the quarter and nine months ended September 30, 2014 primarily due to higher severance taxes associated with our higher oil production.

(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) The nine months ended September 30, 2013, include a reduction in sales and use taxes of $13 million associated with settling a sales and use tax matter.

Other Income Statement Items.

Other expense. For the quarter and nine months ended September, 30, 2013, we recorded losses on our equity investment in Four Star as a result of an impairment recorded upon our decision to sell our investment. The impairment of $20 million was based on comparison of $183 million in net proceeds received for the sale of Four Star in September 2013 to the underlying carrying value of the investment.

Loss on extinguishment of debt. For the nine months ended September 30, 2014, we recorded a $17 million loss 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. For the quarter and nine months ended September 30, 2013, we recorded $6 million and $9 million in losses on extinguishment of debt for the portion of deferred financing costs written off in conjunction with (i) the repayment of approximately $250 million under each of our $750 million and $400 million term loans, (ii) our $750 million term loan repricing in May 2013 and (iii) the semi-annual redetermination of our RBL Facility in March 2013.

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Interest expense. Interest expense for the quarter and nine months ended September 30, 2014 decreased compared to the same periods 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 and nine months ended September 30, 2014, our effective tax rates were 38% and 42%, respectively, which differs from the statutory federal tax rate of 35% as a result of the effects of state income taxes, non-deductible compensation expense, and discrete adjustments for certain transaction costs related to our initial public offering. We expect our annual effective tax rate to be approximately 38%. The effective tax rate for the quarter and nine months ended September 30, 2013, were (26%) and (44%), significantly lower than the statutory rate primarily due to only recording income tax expense subsequent to the Corporate Reorganization on August 30, 2013 and the level of pretax income during the period.

(Loss) income from discontinued operations. Our (loss) income from discontinued operations for the quarter and nine months ended September 30, 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.

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Supplemental Non-GAAP Measures

We use the non-GAAP measures EBITDAX and Adjusted EBITDAX as supplemental measures. We believe these supplemental measures provide meaningful information to our investors. We define EBITDAX as income (loss) from continuing operations plus interest and debt expense, income taxes, depreciation, depletion and amortization and exploration expense. Adjusted EBITDAX is defined as EBITDAX, adjusted as applicable in the relevant period for the net change in the fair value of derivatives (mark-to-market effects of financial derivatives, net of cash settlements and premiums related to these derivatives), the non-cash portion of compensation expense (which represents non-cash compensation expense under our long-term incentive programs adjusted for cash payments made under our long-term incentive plans), transition, restructuring and other non-recurring costs, management and other fees paid to our Sponsors, losses on extinguishment of debt, equity earnings from Four Star prior to its sale in 2013, and impairment charges.

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:

	Quarters ended September 30, 2014	Quarters ended September 30, 2013	Nine months ended September 30, 2014	Nine months ended September 30, 2013
	(in millions)			
Net income	$ 305	$ 310	$ 97	$ 397
Loss (income) from discontinued operations, net of tax	1	(456)	(3)	(495)
Income (loss) from continuing operations	306	(146)	94	(98)
Income tax expense	191	30	67	30
Interest expense, net of capitalized interest	76	91	235	269
Depreciation, depletion and amortization	228	164	634	417
Exploration expense	5	12	18	37
EBITDAX	806	151	1,048	655
Mark-to-market on financial derivatives(1)	(381)	142	44	107
Cash settlements and premiums on financial derivatives(2)	(3)	(25)	(60)	(2)
Non-cash portion of compensation expense(3)	2	8	6	22
Transition, restructuring and other costs(4)	(6)		(5)	7
Fees paid to Sponsors(5)		6	90	19
Loss on extinguishment of debt(6)		6	17	9
Loss from unconsolidated affiliate(7)		19		13
Impairment charges	1	2	1	2
Adjusted EBITDAX	$ 419	$ 309	$ 1,141	$ 832

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

(2) Represents actual cash settlements received/(paid) related to financial derivatives, including cash premiums. No cash premiums were received for the quarter ended September 30, 2014. For the quarter ended September 30, 2013, we received approximately $1 million of cash premiums. For the nine months ended September 30, 2014 and 2013, we received approximately $1 million and approximately $9 million, respectively, of cash premiums.

(3) For the quarter and nine months ended September 30, 2014, cash payments were less than $1 million and approximately $13 million, respectively, and for the nine months ended September 30, 2013 cash payments were approximately $10 million.

(4) Reflects an $11 million insurance settlement and $5 million of acquisition costs in the third quarter of 2014 as well as transition and severance costs related to restructuring.

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

(6) 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.

(7) Reflects the elimination of equity income (losses) recognized from Four Star, net of amortization of our purchase cost in excess of our equity interest in the underlying net assets, as a result of the sale of Four Star in September 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 September 30, 2014, our available liquidity was approximately $1.9 billion, including approximately $1.8 billion of additional borrowing capacity available under the RBL Facility. In October 2014, we completed our semi-annual redetermination of this facility, increasing the borrowing base to $2.75 billion. Our next redetermination date is in April 2015.

We believe we have sufficient liquidity from our cash flows from operations, combined with availability under the RBL Facility ($2.1 billion after the October 2014 redetermination) and available cash, to fund our capital program, current obligations and projected working capital requirements in 2014 and the foreseeable future. Additionally, the earliest maturity date of our obligations is in 2017. Furthermore, despite the recent declines in oil prices, we believe our oil and natural gas derivative contracts provide significant commodity price protection to a substantial portion of our anticipated remaining production for 2014, and in 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. For example, with a $10 per barrel reduction in index prices on oil sold during the third quarter ended September 30, 2014, our total revenues would have only decreased by approximately $5 million.

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 2014, we expect our capital budget will be approximately $2 billion, substantially all of which will be expended in our oil programs. Our accrual based capital expenditures and our average drilling rigs for the nine months ended September 30, 2014 were:

	Capital Expenditures (in millions)		Average Drilling Rigs
Eagle Ford Shale	$	805	5.5
Wolfcamp Shale(1)		647	3.5
Altamont		205	3.0
Haynesville Shale		6	

Total capital expenditures	$	1,663	12.0

(1) Includes approximately $154 million of acquisition capital.

Long-Term Debt. As of September 30, 2014, our long-term debt is approximately $4.4 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 $630 million outstanding under the RBL Facility expiring in 2017. We continually monitor the debt capital markets and our capital structure and will make changes to our capital structure from time to time, with the goal of maintaining flexibility and cost efficiency. For additional details on our long-term debt, including restrictive covenants under our debt agreements, see Part I, Item 1, Financial Statements, Note 7.

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

	Nine months ended September 30, 2014	2013
Cash Flow from Operations		
Operating activities		
Net income	$ 97	$ 397
Impairment charges	19	28
Other income adjustments	763	181
Change in other assets and liabilities	27	181
Total cash flow from operations	$ 906	$ 787
Other Cash Inflows		
Investing activities		
Proceeds from the sale of assets, net of cash transferred	$ 126	$ 1,439
Financing activities		
Proceeds from long-term debt	1,835	1,310
Proceeds from issuance of stock	669	
Other		12
	2,504	1,322
Total cash inflows	$ 2,630	$ 2,761
Cash Outflows		
Investing activities		
Capital expenditures	$ 1,521	$ 1,420
Cash paid for acquisitions, net of cash acquired	154	2
	1,675	1,422
Financing activities		
Repayment of long-term debt	1,895	1,915
Distributions to members		205
	1,895	2,120
Total cash outflows	$ 3,570	$ 3,542
Net change in cash and cash equivalents	$ (34)	$ 6

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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 September 30, 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)	$ 121	$ (286)	$ (407)	$ 523	$ 402

	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)	$ 121	$ 120	$ (1)	$ 122	$ 1
Credit rate(3)	$ 121	$ 120	$ (1)	$ 121	$

(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 September 30, 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 September 30, 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 nine months of 2014 that materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

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

Item 1A. Risk Factors

There have been no material changes to the risk factors previously disclosed in the 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.

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: November 5, 2014	/s/ Dane E. Whitehead Dane E. Whitehead Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: November 5, 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 * . All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
*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.