EP Energy Corp
Form 10-Q
October 27, 2016
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2016
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) 997-1000
Internet Website: www.epenergy.com

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.:

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

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

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

Class A Common Stock, par value $0.01 per share. Shares outstanding as of October 17, 2016: 251,663,516

Class B Common Stock, par value $0.01 per share. Shares outstanding as of October 17, 2016: 782,667

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

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

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

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

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

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

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

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

Forward-looking statements are subject to risks and uncertainties. While we believe the assumptions or bases underlying the forward-looking statements are reasonable and are made in good faith, we caution that assumed facts or bases almost always vary from actual results, and these differences 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 2015 Annual Report on Form 10-K. There have been no material changes to the risk factors described in the Form 10-K.

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PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarter ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Operating revenues				
Oil	$169	$245	$463	$781
Natural gas	27	58	94	152
NGLs	16	16	42	44
Financial derivatives	43	434	(20)	458
Total operating revenues	255	753	579	1,435
Operating expenses				
Oil and natural gas purchases	2	9	9	24
Transportation costs	27	30	81	82
Lease operating expense	37	45	117	139
General and administrative	31	32	101	114
Depreciation, depletion and amortization	132	260	342	737
Loss (gain) on sale of assets	4	—	(78)	—
Exploration and other expense	1	2	3	14
Taxes, other than income taxes	15	20	43	65
Total operating expenses	249	398	618	1,175
Operating income (loss)	6	355	(39)	260
Gain (loss) on extinguishment of debt	26	—	384	(41)
Interest expense	(74)	(84)	(231)	(249)
(Loss) income before income taxes	(42)	271	114	(30)
Income tax expense (benefit)	1	95	1	(13)
Net (loss) income	$(43)	$176	$113	$(17)
Basic net income (loss) per common share				
Net (loss) income	$(0.18)	$0.72	$0.46	$(0.07)
Basic weighted average common shares outstanding	245	244	245	244
Diluted net income (loss) per common share				
Net (loss) income	$(0.18)	$0.72	$0.46	$(0.07)
Diluted weighted average common shares outstanding	245	244	246	244

See accompanying notes.

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

	September 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 40	$ 26
Accounts receivable		
Customer, net of allowance of less than $1 in 2016 and $1 in 2015	125	189
Other, net of allowance of $1 in 2016 and 2015	7	12
Income tax receivable	2	3
Materials and supplies	20	24
Derivative instruments	212	694
Assets held for sale	—	344
Prepaid assets	5	5
Total current assets	411	1,297
Property, plant and equipment, at cost		
Oil and natural gas properties	7,078	6,721
Other property, plant and equipment	84	80
	7,162	6,801
Less accumulated depreciation, depletion and amortization	2,674	2,374
Total property, plant and equipment, net	4,488	4,427
Other assets		
Derivative instruments	24	85
Unamortized debt issue costs - revolving credit facility	13	23
Other	1	1
	38	109
Total assets	$ 4,937	$ 5,833

See accompanying notes.

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

	September 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$ 59	$ 69
Other	122	164
Accrued interest	81	47
Asset retirement obligations	1	1
Liabilities related to assets held for sale	—	24
Other liabilities	85	46
Total current liabilities	348	351
Long-term debt, net of debt issue costs	3,796	4,812
Other long-term liabilities		
Derivative instruments	—	8
Asset retirement obligations	40	37
Other	9	6
Total non-current liabilities	3,845	4,863
Commitments and contingencies (Note 8)		
Stockholders' equity		
Class A shares, $0.01 par value; 550 million shares authorized; 252 million shares issued and outstanding at September 30, 2016; 248 million shares issued and outstanding at December 31, 2015	2	2
Class B shares, $0.01 par value; 0.8 million shares authorized, issued and outstanding at September 30, 2016 and December 31, 2015	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Treasury stock (at cost); 0.4 million shares at September 30, 2016 and 0.1 million shares at December 31, 2015	(2)	—
Additional paid-in capital	3,543	3,529
Accumulated deficit	(2,799)	(2,912)
Total stockholders' equity	744	619
Total liabilities and equity	$ 4,937	$ 5,833

See accompanying notes.

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

	Nine months ended September 30,	
	2016	2015
Cash flows from operating activities		
Net income (loss)	$113	$(17)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation, depletion and amortization	342	737
Gain on sale of assets	(78)	—
Deferred income tax benefit	—	(14)
(Gain) loss on extinguishment of debt	(384)	41
Other	27	38
Asset and liability changes		
Accounts receivable	84	45
Accounts payable	(36)	(56)
Derivative instruments	535	196
Accrued interest	34	49
Other asset changes	4	21
Other liability changes	17	(1)
Net cash provided by operating activities	658	1,039
Cash flows from investing activities		
Cash paid for capital expenditures	(398)	(1,203)
Proceeds from the sale of assets	389	—
Cash paid for acquisitions, net of cash acquired	—	(114)
Net cash used in investing activities	(9)	(1,317)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	630	1,777
Repayments and repurchases of long-term debt	(1,239)	(1,473)
Purchases of treasury stock	(2)	—
Other	(24)	(20)
Net cash (used in) provided by financing activities	(635)	284
Change in cash and cash equivalents	14	6
Cash and cash equivalents		
Beginning of period	26	22
End of period	$40	$28

See accompanying notes

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

	Class A Stock		Class B Stock		Treasury	Additional Paid-in	(Accumulated Deficit) Retained	
	Shares	Amount	Shares	Amount	Stock	Capital	Earnings	Total
Balance at December 31, 2015	248	$ 2	0.8	$ —	$ —	$ 3,529	$ (2,912)	$ 619
Share-based compensation	4	—	—	—	(2)	14	—	12
Net income	—	—	—	—	—	—	113	113
Balance at September 30, 2016	252	$ 2	0.8	$ —	$ (2)	$ 3,543	$ (2,799)	$ 744

See accompanying notes.

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation

We prepared this Quarterly Report on Form 10-Q under the rules and regulations of the United States Securities and Exchange Commission (SEC) and in accordance with United States generally accepted accounting principles (U.S. GAAP) as it applies to interim financial statements. Because this is an interim period report presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP and should be read along with our 2015 Annual Report on
Form 10-K. The condensed consolidated financial statements as of September 30, 2016 and 2015 are unaudited. The consolidated balance sheet as of December 31, 2015 has been derived from the audited consolidated balance sheet included in our 2015 Annual Report on Form 10-K. In our opinion, all adjustments which are of a normal, recurring nature are reflected to fairly present these interim period results. The results for any interim period are not necessarily indicative of the expected results for the entire year.

Significant Accounting Policies

There were no changes in significant accounting policies as described in the 2015 Annual Report on Form 10-K.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standards have been issued but not yet adopted as of September 30, 2016.

Statement of Cash Flows. In August 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-15, Statement of Cash Flows- Classification of Certain Cash Receipts and Cash Payments, which addresses eight specific cash flow issues with the objective of reducing the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. Retrospective application of this standard is required beginning after December 15, 2017, including interim periods within those fiscal years, and early adoption is allowed. We do not anticipate that the adoption of this standard will have a material impact on our consolidated statement of cash flows.

Stock Compensation. In March 2016, the FASB issued ASU No. 2016-09, Improvements to Employee Share-Based Payment Accounting, which updates several aspects of the accounting for and disclosure of share-based payment transactions. Adoption of this standard is required beginning in the first quarter of 2017 and early adoption is allowed. We do not anticipate that the adoption of this standard will have a material impact on our financial statements.

Leases. In February 2016, the FASB issued ASU No. 2016-02, Leases, which requires lessees to recognize lease assets and lease liabilities on the balance sheet and disclose key information about leasing arrangements. Adoption of this standard is required beginning in the first quarter of 2019 and early adoption is allowed. We are evaluating the impact this update will have on our financial statements.

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

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2. Divestitures

In May 2016, we completed the sale of our assets located in the Haynesville and Bossier shales for approximately $420 million (net cash proceeds of $388 million after customary adjustments) with the buyer also assuming a transportation commitment totaling $106 million. We recorded a gain on the sale of approximately $79 million. We classified the assets and liabilities associated with the assets sold as held for sale on our consolidated balance sheet as of December 31, 2015.
Summarized operating results and financial position data of our assets held for sale were as follows (in millions):

	Quarter ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Operating revenues	$ —	$ 21	$ 26	$ 57
Operating expenses				
Transportation costs	—	5	7	16
Lease operating expense	—	1	1	4
Depreciation, depletion and amortization	—	9	16	22
Other expense	—	2	5	8
Total operating expenses	—	17	29	50
(Loss) gain on sale of assets	(4)	—	79	—
(Loss) income before income taxes	$ (4)	$ 4	$ 76	$ 7

	December 31, 2015
Assets	
Current assets	$ 16
Property, plant and equipment, net	328
Total assets held for sale	$ 344
Liabilities	
Accounts payable	$ 17
Other current liabilities	4
Asset retirement obligations	3
Total liabilities related to assets held for sale	$ 24

Acquisitions. In September 2015, we acquired approximately 12,000 net acres adjacent to our existing Eagle Ford Shale acreage for an adjusted cash purchase price of approximately $114 million. No goodwill or bargain purchase was recorded on the acquisition.

3. Income and Other Taxes

Effective Tax Rate. Interim period income taxes are computed by applying an anticipated annual effective tax rate to year-to-date income or loss, except for significant, unusual or infrequently occurring items, which income tax effects are recorded in the period in which they occur. Changes in tax laws or rates are recorded in the period they are enacted.
For the quarter and nine months ended September 30, 2016, our effective tax rates were approximately 1%. Our effective tax rates differed from the statutory rate as a result of adjustments to the valuation allowance on our deferred

tax assets which offset deferred income tax benefit by $16 million and deferred income tax expense by $43 million for the quarter and nine months ended September 30, 2016, respectively. We evaluate the realization of our deferred tax assets and record a valuation allowance after considering cumulative book losses, the reversal of existing temporary differences, the existence of taxable income in prior carryback years, tax planning strategies and future taxable income for each of our taxable jurisdictions. Based upon the evaluation of the available evidence, we maintained a valuation allowance against our net deferred tax assets of $932 million as of September 30, 2016.

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For the quarter and nine months ended September 30, 2015, our effective tax rates were 35% and 42%, respectively. Our effective tax rate for the nine months ended September 30, 2015 differs from the statutory rate primarily as a result of the
effects of state income taxes (net of federal income tax effects) relative to our level of pre-tax book income (loss).

Other. The Company's and certain subsidiaries' income tax years remain open and subject to examination by both federal and state tax authorities. One of our subsidiary's 2013 U.S. tax return is under examination by the IRS. We are also under a number of other examinations by taxing authorities related to non-income tax matters. During the quarter ended September 30, 2016, we accrued approximately $22 million in connection with these examinations related to certain prior year non-income tax matters. In conjunction with recording the accrual, we recorded approximately $19 million in additional depreciation, depletion and amortization expense as certain prior year costs would have been historically capitalized and amortized or impaired in prior periods, with the remainder recorded as interest expense.

4. Earnings Per Share

We exclude potentially dilutive securities from the determination of diluted earnings per share (as well as their related income statement impacts) when their impact on net income per common share is antidilutive. Potentially dilutive securities consist of employee stock options, restricted stock and performance units. For the nine months ended September 30, 2016, approximately 1 million shares are included as dilutive securities in our calculation of diluted earnings per share. For the quarter ended September 30, 2015, potentially dilutive securities did not have a material effect upon our diluted earnings per share. For the quarter ended September 30, 2016 and the nine months ended September 30, 2015, we incurred net losses and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive.

5. Fair Value Measurements

We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of September 30, 2016 and December 31, 2015, all derivative financial instruments were classified as Level 2. Our assessment of the level of an instrument can change over time based on the maturity or liquidity of the instrument.

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

	September 30, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt (see Note 7)	$3,856	$3,064	$4,869	$3,379
Derivative instruments	$236	$236	$771	$771

As of September 30, 2016 and December 31, 2015, 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 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.

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, 2016, we had derivative contracts in the form of fixed price swaps and three-way collars on 17 MMBbls of oil (4 MMBbls in 2016 and 13 MMBbls in 2017). We also had derivative contracts that offset these positions on 0.2 MMBbls of 2016 fixed price swaps. In addition to our oil derivatives, we had 17 TBtu of fixed price swaps on natural gas and 4 MMGal of fixed price swaps on propane. As of December 31, 2015, we had fixed price derivative contracts for 23 MMBbls of oil, 7 TBtu of natural gas and 15 MMGal of propane. We also have derivative contracts related to locational basis differences and/or timing of physical settlement prices on our oil production. None of our derivative contracts are designated as accounting hedges.

The following table presents the fair value associated with our derivative financial instruments as of September 30, 2016 and December 31, 2015. 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

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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		Balance Sheet Location		Gross		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, 2016								
Derivative instruments	$254	$ (18)	$ 212	$ 24	$(18)	$ 18	$ —	$ —
December 31, 2015								
Derivative instruments	$795	$ (16)	$ 694	$ 85	$(24)	$ 16	$ —	$ (8)

For the quarters ended September 30, 2016 and 2015, we recorded derivative gains of $43 million and $434 million, respectively, on our oil, natural gas and NGLs financial derivative instruments. For the nine months ended September 30, 2016 and 2015, we recorded derivative losses of $20 million and derivative gains of $458 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated statement of income. In June 2016, we exchanged LLS fixed price swaps on our 2016 oil positions for 7.7 MMBbls of WTI three way collars in 2017. The exchange was non-cash with no gain or loss recognized on the transaction.

Interest Rate Derivative Instruments. We have interest rate swaps with a notional amount of $600 million that extend through March 2017 and are intended to reduce variable interest rate risk. As of September 30, 2016, we had a net liability of less than $1 million and as of December 31, 2015, we had a net asset of $1 million related to interest rate derivative instruments included on our consolidated balance sheets. For the quarters ended September 30, 2016 and 2015, we recorded less than $1 million and $2 million, respectively, of interest expense related to the change in fair market value and cash settlements of our interest rate derivative instruments. For the nine months ended September 30, 2016 and 2015, we recorded $2 million and $7 million of interest expense, respectively, related to the change in fair market value and cash settlements of our interest rate derivative instruments.

6. Property, Plant and Equipment

Oil and Natural Gas Properties. As of September 30, 2016 and December 31, 2015, we had approximately $4.5 billion and $4.4 billion of total property, plant, and equipment, net of accumulated depreciation, depletion and amortization on our consolidated balance sheets, substantially all of which relates to proved and unproved oil and natural gas properties.

Our capitalized costs related to proved and unproved oil and natural gas properties by area were as follows:

	September 30, 2016	December 31, 2015
	(in millions)	
Proved		
Eagle Ford	$2,979	$ 2,833
Wolfcamp	2,337	2,174
Altamont	1,609	1,553
Total Proved	6,925	6,560
Unproved		
Wolfcamp	94	97
Altamont	59	64

Total Unproved	153	161
Less accumulated depletion	2,626	2,335
Net capitalized costs for oil and natural gas properties	$ 4,452	$ 4,386

During the nine months ended September 30, 2016, we transferred approximately $8 million from unproved properties to proved properties. For both of the quarters ended September 30, 2016 and 2015, we recorded approximately $1 million of amortization of unproved leasehold costs in exploration expense in our consolidated statement of income. For the nine months ended September 30, 2016 and 2015, we recorded approximately $1 million and $9 million, respectively, of amortization of unproved leasehold costs. Suspended well costs were not material as of September 30, 2016 or December 31, 2015.

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We evaluate capitalized costs related to proved properties at least annually or upon a triggering event (such as a significant forward commodity price decline) to determine if impairment of such properties has occurred. Capitalized costs associated with unproved properties (e.g. leasehold acquisition costs associated with non-producing areas) are also assessed for impairment based on estimated drilling plans and capital expenditures which may also change relative to forward commodity prices and/or potential lease expirations. Commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in an impairment of the carrying value of our proved and/or unproved properties in the future.

Leasehold acquisition costs associated with non-producing or unproved areas are assessed for impairment based on our estimated drilling plans and capital expenditures relative to potential lease expirations. Generally, economic recovery of unproved reserves in such areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by continuing exploration and development activities. Our ability to retain our leases and thus recover our non-producing leasehold costs will be dependent upon a number of factors including our levels of drilling activity, which may include drilling the acreage on our own behalf or jointly with partners, or our ability to modify or extend our leases. Should oil prices not justify sufficient capital allocation to the continued development of properties where we have these non-producing leasehold costs, we could incur impairment charges of our unproved property costs. In May 2016, we amended our Wolfcamp development agreement with the University Lands to provide flexibility to extend the time frame to hold our acreage by nearly four years to the end of 2021, with an increase in annual well completion requirements from six wells per year to 34, 55 and 55 wells per year in 2016, 2017 and 2018, respectively. Currently, we have the intent and believe we have the ability to fulfill our annual Wolfcamp drilling commitment and/or develop our unproved areas prior to having to relinquish any associated leases.

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

In estimating the liability associated with our asset retirement obligations, we utilize several assumptions, including a credit-adjusted risk-free rate between 7-9 percent on a significant portion of our obligations and a projected inflation rate of 2.5 percent. Changes in estimates represent changes to the expected amount and timing of payments to settle our asset retirement obligations. Typically, these changes result from obtaining new information about the timing of our obligations to plug and abandon oil and natural gas wells and the costs to do so, or reassessing our assumptions in light of market conditions. The net asset retirement liability as of September 30, 2016 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, 2016 were as follows:

	2016 (in millions)
Net asset retirement liability at January 1	$ 38
Accretion expense	2
Changes in estimate	1
Net asset retirement liability at September 30	$ 41

Capitalized Interest. Interest expense is reflected in our financial statements net of capitalized interest. We capitalize interest primarily on the costs associated with drilling and completing wells until production begins. The interest rate used is
the weighted average interest rate of our outstanding borrowings. Capitalized interest for the quarter and nine months ended September 30, 2016 was approximately $1 million and approximately $3 million, respectively. Capitalized interest for the quarter and nine months ended September 30, 2015 was approximately $3 million and $12 million, respectively.

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7. Long-Term Debt

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

	Interest Rate	September 30, 2016	December 31, 2015
		(in millions)	
RBL credit facility - due May 24, 2019[1]	Variable	$870	$ 1,072
Senior secured term loan - due May 24, 2018[2][4]	Variable	21	497
Senior secured term loan - due April 30, 2019[3][4]	Variable	8	150
Senior secured term loan - due June 30, 2021[5][6]	Variable	580	—
Senior unsecured notes - due May 1, 2020	9.375%	1,576	2,000
Senior unsecured notes - due September 1, 2022	7.75%	250	350
Senior unsecured notes - due June 15, 2023	6.375%	551	800
Total long-term debt		3,856	4,869
Less unamortized debt issue costs		(60)	(57)
Total long-term debt, net		$3,796	$ 4,812

(1) Carries interest at a specified margin over LIBOR of 2.50% to 3.50%, based on borrowing utilization.

(2) 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, 2016 and December 31, 2015, the effective interest rate of the term loan was 3.50%.

(3) Carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of September 30, 2016 and December 31, 2015, the effective interest rate for the term loan was 4.50%.

(4) Secured by a second priority lien on all of the collateral securing the RBL Facility, and effectively rank junior to any existing and future priority lien secured indebtedness of the Company.

(5) Carries an interest rate of LIBOR plus 8.75%, with a minimum LIBOR floor of 1.00%. As of September 30, 2016, the effective interest rate for the term loan was 9.75%.

(6) Secured by a priority lien on all of the collateral securing the RBL Facility, and effectively ranks junior to RBL indebtedness and senior priority lien indebtedness.

In August 2016, we exchanged approximately 95% of the outstanding amount of our term loans maturing in May 2018 and April 2019 for new term loans with an aggregate principal amount of approximately $580 million. The new term loans have an interest rate of LIBOR plus 8.75%, with a floor of 1.00% and a maturity date of June 30, 2021. However, if the aggregate principal amount of our existing 9.375% senior unsecured notes due on May 1, 2020 exceeds $325 million 91 days prior to its maturity, the maturity date of the 2021 term loans would accelerate to January 31, 2020.

During the nine months ended September 30, 2016, we paid approximately $407 million in cash to repurchase a total of approximately $812 million in aggregate principal amount of our senior unsecured notes and term loans which resulted in a gain on extinguishment of debt of approximately $26 million and $393 million for the quarter and nine months ended September 30, 2016 (including $1 million and $12 million, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs). For the nine months ended September 30, 2016, we also recorded losses on the extinguishment of debt of $9 million, primarily related to eliminating a portion of the unamortized debt issue costs upon the reduction of our RBL borrowing base in May 2016.

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

Unamortized Debt Issue Costs. As of September 30, 2016 and December 31, 2015, we had total unamortized debt issue costs of $73 million and $80 million. Of these amounts, $13 million and $23 million, respectively, are associated with our Reserve-Based Loan facility (RBL Facility) and $60 million and $57 million, respectively, are associated with our senior secured term loans and senior notes. During the quarter ended September 30, 2016, we recorded an additional $23 million in deferred financing costs in conjunction with the exchange of $580 million in new term loans for approximately 95% of the outstanding amount of our 2018 and 2019 term loans. During the quarter and nine months ended September 30, 2016, we expensed approximately $1 million and $20 million, respectively, in conjunction with the repurchase of a portion of our senior unsecured notes and term loans and the reduction of our RBL borrowing base. During both of the quarters and for each of the nine months ended September 30, 2016 and 2015, we amortized $4 million, $12 million and $14 million, respectively, of deferred financing costs into interest expense.

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Reserve-based Loan Facility. We have a reserve-based credit facility in place which allows us to borrow funds or issue letters of credit. The facility matures in May 2019. The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In May 2016, we completed our semi-annual redetermination, and the borrowing base of our RBL Facility was reduced to $1.65 billion, reflecting significantly lower bank commodity price forecasts, the sale of our Haynesville assets and the roll-off of certain hedge positions. Our next redetermination date is in November 2016. Downward revisions of our oil and natural gas reserves as a result of declines in commodity prices, performance revisions, or sales of assets, or the incurrence of certain types of additional debt, among other items, could cause a further reduction of our borrowing base which could negatively impact our borrowing capacity under the RBL Facility in the future.

As of September 30, 2016, we had $763 million of available capacity remaining with approximately $17 million of letters of credit issued and approximately $870 million outstanding under the facility.

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. At September 30, 2016 we were in compliance with all of our debt covenants. In conjunction with our RBL Facility redetermination in May 2016, we amended certain covenants, the most significant of which suspended the requirement that our debt to EBITDAX ratio, as defined in the credit agreement, not exceed 4.5 to 1.0 and replaced it with a requirement that our ratio of first lien debt to EBITDAX not exceed 3.5 to 1.0. The 4.5 to 1.0 debt to EBITDAX requirement will be reinstated beginning in April 2018. As part of the amendment, we also agreed to limit debt repurchases occurring after the redetermination to $350 million subject to certain future adjustments.

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 matter, 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 and adjust our accruals accordingly, and these adjustments could be material. As of September 30, 2016, we had approximately $2 million accrued for all outstanding legal matters.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestitures of assets or businesses. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes, environmental and other contingent matters. In addition, under various laws or regulations, we could be subject to the imposition of certain liabilities. For example, the recent decline in commodity prices has created an environment where there is an increased risk that owners and/or operators of assets previously purchased from us may no longer be able to satisfy plugging and abandonment obligations that attach to such assets. In that event, under various laws or regulations, we could be required to assume these plugging or abandonment obligations on assets no longer owned or operated by us. As of September 30, 2016, we had approximately $8 million accrued related to these indemnifications and other matters.

Environmental Matters

We are subject to existing federal, state and local laws and regulations governing environmental quality, pollution control and greenhouse gas (GHG) emissions. Numerous governmental agencies, such as the Environmental Protection Agency (EPA), issue regulations which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically sensitive areas, seismically active areas and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or relate to our owned or operated facilities. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and

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regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements.

The environmental laws and regulations to which we are subject also require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of September 30, 2016, we had accrued and had exposure of approximately $1 million for related environmental remediation costs associated with onsite, offsite and groundwater technical studies and for related environmental legal costs. Our accrual represents a combination of two estimation methodologies. First, where the most likely outcome can be reasonably estimated, that cost has been accrued. Second, where the most likely outcome cannot be estimated, a range of costs is established and if no one amount in that range is more likely than any other, the lower end of the expected range has been accrued. Our environmental remediation projects are in various stages of completion. The liabilities we have recorded reflect our current estimates of amounts that we will expend to remediate these sites. However, depending on the stage of completion or assessment, the ultimate extent of contamination or remediation required may not be known. As additional assessments occur or remediation efforts continue, we may incur additional liabilities.

Climate Change and Other Emissions. In recent years, federal, state and local governments have taken steps to reduce GHG emissions. The EPA has finalized a series of GHG monitoring, reporting and emission control rules for the oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. In December 2015, the United States joined the international community at the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake ambitious efforts to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement establishes a framework for the parties to cooperate and report actions to reduce GHG emissions. 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.

As part of the White House’s Climate Action Plan Strategy to Reduce Methane Emissions, the EPA, the Pipeline and Hazardous Materials Safety Administration (PHMSA) and the Bureau of Land Management (BLM) have recently proposed or finalized new regulations affecting the oil and gas industry. On October 13, 2015, the PHMSA published a proposed rule for oil pipelines, in part requiring inspections in areas affected by natural disasters, expanding use of leak detection systems, and requiring increased use of inline inspection tools. On January 22, 2016, the BLM released a proposed rule for oil and gas facilities on onshore federal and Indian leases to prohibit venting, limit flaring, require leak detection, and allow adjustment of royalty rates for new leases. Although we are examining these proposed regulations, it is uncertain what impact they might have on our operations until they are implemented.

On September 18, 2015, the EPA published several proposed regulations under the Clean Air Act to reduce methane and volatile organic compounds emissions, in part through green completions at oil wells, fugitive emission surveys, limits on pneumatic pumps and controllers, and draft guidelines for controls on equipment in ozone nonattainment areas. These rules were published on June 3, 2016 and went into effect August 2, 2016. We are evaluating whether any material capital expenditure will be required for initial and ongoing compliance with these rules.

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. Additional amendments to the new standard were finalized in 2013 through 2016. We do not anticipate material capital expenditures to meet these requirements.

The EPA has promulgated regulations to require pre-construction permits for minor sources of air emissions in tribal lands. On September 18, 2015, the EPA proposed a federal implementation plan (FIP), rather than a general permit, to effect these regulations. The FIP was finalized on June 3, 2016, requiring registration of such new and modified minor sources beginning October 3, 2015 and incorporating emission limits and other requirements from six standards under the Clean Air Act for the oil and gas industry. Additionally, the FIP requires an operator to document compliance with the Endangered

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Species Act and National Historic Preservation Act. This rule could delay pad construction and commencement of drilling if the EPA does not timely provide written confirmation that requisites of the FIP have been met.
Hydraulic Fracturing Regulations. We use hydraulic fracturing extensively in our operations. Various regulations have been adopted and proposed at the federal, state and local levels to regulate hydraulic fracturing operations. These regulations range from banning or substantially limiting hydraulic fracturing operations, requiring disclosure of the hydraulic fracturing fluids and requiring additional permits for the use, recycling and disposal of water used in such operations. In addition, various agencies, including the EPA and Department of Energy, are reviewing changes in their regulations to address the environmental impacts of hydraulic fracturing operations. Until such regulations are implemented, it is uncertain what impact they might have on our operations. In March 2015, the BLM published final rules for hydraulic fracturing on federal and certain tribal lands, including use of tanks for recovered water, updated cementing and testing requirements, and disclosure of chemicals used in hydraulic fracturing. Several states and the Ute Indian Tribe filed suit to challenge these rules. On September 30, 2015, a federal court issued a preliminary injunction suspending the rules and, on June 21, 2016, ordered the rules set aside as exceeding the BLM's authority. The BLM has filed an appeal in the Tenth Circuit Court of Appeals. No material cost is expected for the Company's 2016 program.
Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) Matters. As part of our environmental remediation projects, we are or have received notice that we could be designated as a Potentially Responsible Party (PRP) with respect to one active site under the CERCLA or state equivalents. As of September 30, 2016, we have estimated our share of the remediation costs at this site to be less than $1 million. Because the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal CERCLA statute may be joint and several, meaning that we could be required to pay in excess of our pro-rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in estimating our liabilities. Accruals for these matters are included in the reserve for environmental matters discussed above.

Waste Handling. Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements imposed under the Resource Conservation and Recovery Act, as amended, and comparable state laws. We believe that we are in substantial compliance with applicable requirements related to waste handling, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent that our operations require them under such laws and regulations. Any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.
It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws, regulations, and orders of regulatory agencies, as well as claims for damages to property and the environment or injuries to employees and other persons resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

9. Long-Term Incentive Compensation

Our long-term incentive (LTI) programs consist of restricted stock, stock option and performance unit awards. A summary of the changes in our non-vested restricted shares for the nine months ended September 30, 2016 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2015	3,987,654	$ 10.98
Granted	4,627,982	$ 6.10
Vested	(1,180,962)	$ 11.80

Forfeited	(635,338	)	$ 8.93
Non-vested at September 30, 2016	6,799,336		$ 7.71

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During the first quarter of 2016, we granted 83,150 performance units to certain members of EP Energy's management team. Performance units have a target value of $100 per unit; however, the ultimate value of each performance unit will range from zero to $200 depending on the level of total shareholder return (TSR) relative to that of EP Energy’s peer group of companies. The performance units vest in three separate tranches (1 year, 2 year and 3 year calendar periods). For accounting purposes, the performance units are treated as a liability award with the expense recognized on an accelerated basis. The fair value measured at the grant date was approximately $8 million which is subsequently remeasured at the end of each reporting period. As of September 30, 2016, the fair value of these awards (net of forfeitures) was approximately $3 million. The fair value of the performance-based units granted was estimated on the date of grant using a Monte-Carlo simulation for each of three separate performance tranches based on the relative TSR results for each separate tranche period beginning January 1, 2016. The performance units may be settled in either stock or cash at the election of the Board of Directors. Had the performance period ended on September 30, 2016, no shares would have been issued related to these awards.

We record compensation expense on our LTI awards as general and administrative expense over the requisite service period, net of estimates of forfeitures. Pre-tax compensation expense related to all of our LTI awards (both equity and liability based) was approximately $5 million and $15 million for the quarters and nine months ended September 30, 2016 and September 30, 2015, respectively. As of September 30, 2016, we had unrecognized compensation expense of $57 million. We will recognize an additional $6 million related to our outstanding awards during the remainder of 2016, $37 million over the remaining requisite service periods subsequent to 2016 and $14 million should a specified capital transaction occur and the right to such amounts become non-forfeitable.

10. Related Party Transactions

Affiliate Supply Agreement. For the nine months ended September 30, 2016 and 2015, we recorded approximately $6 million and $60 million, respectively, in capital expenditures for amounts expended under supply agreements entered into with an affiliate of Apollo Global Management, LLC to provide certain fracturing materials to our Eagle Ford drilling operations. This agreement was terminated effective May 2016.

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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 2015 Annual Report on Form 10-K. Actual results may differ materially from those contained in any forward-looking statements. Unless otherwise indicated or the context otherwise requires, references in this MD&A section to “we”, “our”, “us” and “the Company” refer to EP Energy Corporation and each of its consolidated subsidiaries.

Our Business

Overview. We are an independent exploration and production company engaged in the development and acquisition 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 three core areas: the Eagle Ford Shale (South Texas), the Wolfcamp Shale (Permian Basin in West Texas) and the Altamont Field in the Uinta Basin (Northeastern Utah). In May 2016, we completed the sale of our assets located in the Haynesville and Bossier shales for approximately $420 million (net proceeds of $388 million in cash after customary adjustments) and recorded a gain on the sale of approximately $79 million.

We evaluate growth opportunities for our asset portfolio that are aligned with our core competencies and that are in areas that we believe can provide us a competitive advantage. Strategic acquisitions of leasehold acreage or acquisitions of producing assets can provide opportunities to achieve our long-term goals by leveraging existing expertise in our core 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. We continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term goals.

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

- growing our proved reserve base and production volumes through the successful execution of our drilling programs or through acquisitions;
- finding and producing oil and natural gas at reasonable costs;
- managing operating 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. Future commodity price declines may cause changes to our future capital, production rates, levels of proved reserves and development plans, all of which impact performance. Additionally, we may be impacted by weather events, regulatory issues or other third party actions outside of our control.

We attempt to mitigate certain risks by entering into longer term contractual arrangements to control costs and by entering into derivative contracts to stabilize cash flows and reduce the financial impact of unfavorable movements in both commodity prices and locational price differences. Because we apply mark-to-market accounting on our derivative contracts, 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 contracts or positions or to alter existing contracts or positions are made based on the goals of the overall company.

Derivative Instruments. Our realized prices from the sale of our oil and natural gas are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our oil and natural gas, and (ii) other contractual pricing adjustments contained in our underlying sales contracts. 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 downward commodity price movements and locational price differences.

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During the nine months ended September 30, 2016, we (i) settled commodity index hedges on approximately 98% of our oil production, 76% of our total liquids production and on 26% of our natural gas production at average floor prices of $80.37 per barrel of oil, $0.55 per gallon of NGLs and $3.77 per MMBtu of natural gas, respectively and (ii) hedged basis risk on 100% of our year-to-date Eagle Ford oil production. To the extent our oil and natural gas production is unhedged, either from a commodity index or locational price perspective, our financial results will be impacted from period to period. The following table and discussion that follows reflects the contracted volumes and the prices we will receive under derivative contracts we held as of September 30, 2016.

	2016		2017	
	Volumes(1)	Average Price(1)	Volumes(1)	Average Price(1)
Oil				
Fixed Price Swaps				
WTI	2,139	$80.03	4,015	$66.11
LLS	1,717	$81.61	—	$—
Three Way Collars				
Ceiling - WTI	—	$—	8,833	$70.37
Floors - WTI(2)	—	$—	8,833	$60.62
Basis Swaps				
LLS vs. WTI(3)	506	$3.91	—	$—
LLS vs. Brent(4)	—	$—	3,650	$(3.14)
Midland vs. Cushing(5)	184	$(0.83)	1,460	$(0.68)
WTI - CM vs. TM(6)	1,717	$0.29	—	$—
NYMEX Roll(7)	1,840	$(0.84)	—	$—
Natural Gas				
Fixed Price Swaps	6	$3.34	11	$3.17
Propane				
Fixed Price Swaps	4	$0.55	—	$—

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

(2) If market prices settle at or below $46.24 in 2017, we will receive a “locked-in” cash settlement of the market price plus $14.38 per Bbl.

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

(4) EP Energy receives Brent plus the basis spread listed and pays LLS.

(5) EP Energy receives Cushing plus the basis spread listed and pays Midland.

(6) EP Energy receives WTI trade month (TM) plus the spread listed and pays WTI calendar month (CM).

(7) These positions hedge the timing risk associated with our physical sales. We generally sell oil for the delivery month at a sales price based on the average NYMEX WTI price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month during the period when the delivery month is prompt (the "trade month roll").

Included in the table above are 7.7 MMBbls of 2017 WTI three way collars that we exchanged in the second quarter for existing LLS fixed price swaps on our 2016 oil positions. The exchange was non-cash with no gain or loss recognized on the transaction. In addition to the derivative contracts presented in the table above, during 2016 we have entered into contracts offsetting 184 MBbls of 2016 LLS fixed price swaps, 552 MBbls of 2016 LLS vs. Brent basis swaps and 2,423 MBbls of 2016 WTI - CM vs. TM of our remaining derivative contracts. By entering into these offsetting positions, we effectively “locked-in” additional net cash settlements of approximately $3 million which will be received during the remainder of 2016.

For the period from October 1, 2016 through October 24, 2016, we entered into additional derivative contracts on approximately 12.8 TBtu of 2017 natural gas fixed price swaps with an average price of $3.32 per MMBtu and 61.3 MMGal of 2018 ethane fixed price swaps with an average price of $0.30 per gallon. We also entered into derivative contracts for 3.7 MBbls of 2017 LLS vs. Brent basis swaps with an average price of $(0.46) per barrel of oil which offset our LLS vs. Brent swap positions listed in the table above.

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Summary of Liquidity and Capital Resources. As of September 30, 2016, we had available liquidity of approximately $803 million, reflecting $763 million of available liquidity on our $1.65 billion RBL borrowing base and $40 million of available cash. During 2016, we have taken a number of steps to maintain or improve our liquidity, strengthen our balance sheet and expand our financial flexibility. These steps have included (i) completing the sale of our Haynesville and Bossier Shale assets in May 2016, (ii) repurchasing over $800 million aggregate principal amount of our unsecured notes and term loans for cash at a discount, (iii) amending certain restrictive debt covenants in our RBL Facility through the first quarter of 2018, (iv) exchanging approximately 95% of the outstanding amount of our May 2018 and April 2019 term loans for new term loans of approximately $580 million with amended terms and a maturity date of June 2021, and (v) entering into hedge transactions to provide additional 2017 price protection. See additional details of these transactions in “Liquidity and Capital Resources”.

Outlook. For the full year 2016, we expect our capital expenditures to be approximately $495 million and our average daily production volumes for the year to be approximately 85.5 MBoe/d to 87.5 MBoe/d, including average daily oil production volumes of approximately 46 MBbls/d to 47 MBbls/d.

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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:

	2016	2015
United States (MBoe/d)		
Eagle Ford Shale	45.5	58.9
Wolfcamp Shale	19.3	19.4
Altamont	16.2	17.4
Haynesville Shale	8.3	12.9
Other	0.1	0.1
Total	89.4	108.7
Oil (MBbls/d)	46.9	61.8
Natural Gas (MMcf/d)	169	196
NGLs (MBbls/d)	14.3	14.1

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes decreased by 13.4 MBoe/d (approximately 23%) and oil production decreased by 11.9 MBbls/d (30%) for the nine months ended September 30, 2016 compared to the same period in 2015. During the nine months ended September 30, 2016, we completed 34 additional operated wells in the Eagle Ford, for a total of 597 net operated wells as of September 30, 2016.

- Wolfcamp Shale—Our Wolfcamp Shale equivalent volumes decreased 0.1 MBoe/d (approximately 1%) and oil production decreased by 1.6 MBoe/d (approximately 17%) for the nine months ended September 30, 2016 compared to the same period in 2015. During the nine months ended September 30, 2016, we completed 23 additional operated wells for a total of 266 net operated wells as of September 30, 2016.

- Altamont—Our Altamont equivalent volumes decreased 1.2 MBoe/d (approximately 7%) for the nine months ended September 30, 2016 compared to the same period in 2015. Altamont produced an average of 11.3 MBbls/d of oil during the nine months ended September 30, 2016, and we completed an additional 11 operated oil wells for a total of 378 net operated wells as of September 30, 2016.

- Haynesville Shale—Our Haynesville Shale equivalent volumes decreased 4.6 MMcf/d (approximately 36%) for the nine months ended September 30, 2016 compared to the same period ended September 30, 2015. We sold our Haynesville Shale assets in May 2016.

Our oil production declines in our Eagle Ford, Wolfcamp and Altamont core areas reflect the slowed pace of development in our drilling programs due to reduced capital spending in the latter part of 2015 and in 2016. Future volumes will be impacted by our levels of capital spending and the timing of that spending. In the current commodity price environment, we may continue to have low spending levels which may result in lower reported volumes in the future.

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Results of Operations

The information in the table below provides a summary of our financial results.

	Quarter ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating revenues				
Oil	$169	$245	$463	$781
Natural gas	27	58	94	152
NGLs	16	16	42	44
Total physical sales	212	319	599	977
Financial derivatives	43	434	(20)	458
Total operating revenues	255	753	579	1,435
Operating expenses				
Oil and natural gas purchases	2	9	9	24
Transportation costs	27	30	81	82
Lease operating expense	37	45	117	139
General and administrative	31	32	101	114
Depreciation, depletion and amortization	132	260	342	737
Loss (gain) on sale of assets	4	—	(78)	—
Exploration and other expense	1	2	3	14
Taxes, other than income taxes	15	20	43	65
Total operating expenses	249	398	618	1,175
Operating income (loss)	6	355	(39)	260
Gain (loss) on extinguishment of debt	26	—	384	(41)
Interest expense	(74)	(84)	(231)	(249)
(Loss) income before income taxes	(42)	271	114	(30)
Income tax expense (benefit)	1	95	1	(13)
Net (loss) income	$(43)	$176	$113	$(17)

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters and nine months ended September 30, 2016 and 2015. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

	Quarter ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Operating revenues:				
Oil	$169	$245	$463	$781
Natural gas	27	58	94	152
NGLs	16	16	42	44
Total physical sales	212	319	599	977
Financial derivatives	43	434	(20)	458
Total operating revenues	$255	$753	$579	$1,435
Volumes:				
Oil (MBbls)	4,137	5,717	12,861	16,885
Natural gas (MMcf)	11,177	19,904	46,281	53,569
NGLs (MBbls)	1,326	1,499	3,908	3,858
Equivalent volumes (MBoe)	7,326	10,533	24,483	29,671
Total MBoe/d	79.6	114.5	89.4	108.7
Prices per unit[(1)]:				
Oil				
Average realized price on physical sales ($/Bbl)[(2)]	$40.85	$42.90	$35.96	$46.25
Average realized price, including financial derivatives ($/Bbl)[(2)(3)]	$74.97	$83.56	$74.96	$80.41
Natural gas				
Average realized price on physical sales ($/Mcf)[(2)]	$2.24	$2.47	$1.85	$2.40
Average realized price, including financial derivatives ($/Mcf)[(3)]	$2.53	$3.65	$2.09	$3.67
NGLs				
Average realized price on physical sales ($/Bbl)	$12.02	$10.62	$10.71	$11.44
Average realized price, including financial derivatives ($/Bbl)[(3)]	$12.23	$12.10	$10.98	$12.48

(1) Oil prices for the quarter and nine months ended September 30, 2016 are calculated including a reduction of less than $1 million and approximately $1 million, respectively, for oil purchases associated with managing our physical sales. Natural gas prices for the quarter and nine months ended September 30, 2016 are calculated including a reduction of
approximately $1 million and $8 million, respectively, for natural gas purchases associated with managing our physical sales. Natural gas prices for the quarter and nine months
ended September 30, 2015 are calculated including a reduction of $9 million and $24 million, respectively, for natural gas purchases associated with managing our physical sales.

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

(3) The quarters ended September 30, 2016 and 2015, include approximately $141 million and $233 million of cash received, respectively, for the settlement of crude oil derivative contracts and approximately $3 million and $23 million of cash received, respectively, for the settlement of natural gas financial derivatives. The nine months ended September 30, 2016 and 2015, include approximately $502 million and $577 million of cash received, respectively, for the settlement of crude oil derivative contracts and approximately $11 million and $68 million of cash received, respectively, for the settlement of natural gas financial derivatives. The quarters ended September 30, 2016 and 2015 also include less than $1 million and approximately $2 million of cash received, respectively, for the settlement of NGLs derivative contracts. The nine months ended September 30, 2016 and 2015 include approximately $1 million and $4 million of cash received, respectively, for the settlement of NGLs derivative contracts. No cash premiums were received or paid for the quarters or nine months ended September 30, 2016 and 2015.

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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, 2016, physical sales decreased by $107 million (34%) and $378 million (39%), respectively, compared to the same periods in 2015. Physical sales have decreased due to lower commodity prices across all commodity types and lower oil volumes reflecting the continued slowed pace of development in our drilling programs due to reduced capital spending in 2015 and in 2016. The table below displays the price and volume variances on our physical sales when comparing the quarters and nine months ended September 30, 2016 and 2015.

	Quarter ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
September 30, 2015 sales	$245	$ 58	$16	$319
Change due to prices	(8)	(6)	2	(12)
Change due to volumes	(68)	(25)	(2)	(95)
September 30, 2016 sales	$169	$ 27	$16	$212
	Nine months ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
September 30, 2015 sales	$781	$ 152	$44	$977
Change due to prices	(132)	(37)	(3)	(172)
Change due to volumes	(186)	(21)	1	(206)
September 30, 2016 sales	$463	$ 94	$42	$599

Oil sales for the quarter and nine months ended September 30, 2016 compared to the same periods in 2015 decreased by $76 million (31%) and $318 million (41%), respectively, due primarily to a decline in oil volumes in all of our oil programs and lower oil prices. For the quarter and nine months ended September 30, 2016 compared to the same periods in 2015, Eagle Ford oil production decreased by 40% (15.9 MBbls/d) and 30% (11.9 MBbls/d), respectively, Wolfcamp oil production decreased by 2% (0.2 MBbls/d) and 17% (1.6 MBbls/d), respectively, and Altamont oil production decreased by 8% (1.0 MBbls/d) and 11% (1.4 MBbls/d), respectively, reflecting the slowed pace of development of our core areas.

Natural gas sales decreased for the quarter and nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to lower natural gas prices and lower volumes. In May 2016, we sold our Haynesville Shale assets. The Haynesville Shale produced a total of 50 MMcf/d of natural gas for the nine months ended September 30, 2016 compared to 78 MMcf/d for the same period in 2015 prior to its sale. Partially offsetting this decrease was natural gas volume growth in Wolfcamp during the quarter and nine months ended September 30, 2016.

Our oil and natural gas is sold at index prices (WTI, LLS and Henry Hub) or posted prices at various delivery points across our producing basins. Realized prices received (not considering the effects of hedges) are generally less than the stated index price as a result of fixed or variable contractual deducts, differentials from the index to the delivery point, adjustments for time, and/or discounts for quality or grade. Generally as the index price of our commodities decreases, the fixed contractual deducts in our physical sales contracts reduce the realized prices we receive on a percentage of NYMEX basis.

In the Eagle Ford, our oil is sold at prices tied to benchmark LLS crude oil. In Wolfcamp, physical barrels are generally sold at the WTI Midland Index, which trades at a spread to WTI Cushing. Pricing for both areas has been influenced by the weakening average price adjustments we receive on physical sales. In Altamont, market pricing of our oil is based upon NYMEX based agreements which reflect transportation and handling costs associated with moving wax crude 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.

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	Quarter ended September 30,			
	2016		2015	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(4.27)	$ (0.57)	$(4.22)	$ (0.33)
NYMEX	$44.94	$ 2.81	$46.43	$ 2.77
Net back realization %	90.5 %	79.7 %	90.9 %	88.1 %

	Nine months ended September 30,			
	2016		2015	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(5.38)	$ (0.44)	$(5.10)	$ (0.41)
NYMEX	$41.33	$ 2.29	$51.00	$ 2.80
Net back realization %	87.0 %	80.8 %	90.0 %	85.4 %

The lower oil realization percentage in the quarter and nine months ended September 30, 2016 relative to the same periods in 2015 was primarily a result of a reduced LLS premium relative to NYMEX in Eagle Ford and a reduced Midland-Cushing basis spread in Wolfcamp, partially offset by improved physical sales contract pricing in Altamont. The lower natural gas realization percentages in the quarter and nine months ended September 30, 2016 were primarily a result of the impact of the sale of our Haynesville assets and its associated lower basis differentials. Also impacting the lower realization percentage were lower flared volumes in the Eagle Ford area in 2016 compared to the same periods in 2015.

NGLs sales remained flat for the quarter ended September 30, 2016 and decreased for the nine months ended September 30, 2016 compared to the same period in 2015. Although slightly higher in the third quarter ended September 30, 2016 compared to the same period in 2015, average realized prices for the nine months ended September 30, 2016 were lower compared to the same period in 2015, due to lower pricing on all liquids components. NGLs pricing is largely tied to crude oil prices. NGLs volumes increased for the nine months ended September 30, 2016 primarily as a result of lower flaring in our Eagle Ford and higher NGLs production in Wolfcamp.

Future growth in our overall oil sales (including the impact of financial derivatives) will largely be impacted by commodity pricing, by our ability to maintain or grow oil volumes, by the location of our production and by the nature of our sales contracts. Based on our hedges in place as of September 30, 2016, we have approximately 4 MMBbls hedged for the remainder of 2016 at a weighted average price of $80.77 per barrel. We also have contracts that effectively "lock-in" additional cash settlements, on 0.2 MMBbls of 2016 LLS fixed price swaps, 0.6 MMBbls of 2016 LLS vs. Brent basis swaps and 2,423 MBbls of 2016 WTI - CM vs. TM, representing approximately $3 million which will be received during the remainder of 2016. See "Our Business" for further information on our derivative instruments.

Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the quarter ended September 30, 2016, we recorded $43 million of derivative gains compared to derivative gains of $434 million during the quarter ended September 30, 2015. For the nine months ended September 30, 2016, we recorded $20 million of derivative losses compared to derivative gains of $458 million during the nine months ended September 30, 2015.

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Operating Expenses

The tables below provide our operating expenses, volumes and operating expenses per unit for the quarters and nine months ended September 30, 2016 and 2015.

	Quarter ended September 30,			
	2016		2015	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Operating expenses				
Oil and natural gas purchases	$ 2	$ 0.25	$ 9	$ 0.90
Transportation costs	27	3.71	30	2.87
Lease operating expense	37	5.13	45	4.25
General and administrative(2)	31	4.21	32	3.02
Depreciation, depletion and amortization	132	17.97	260	24.69
Loss on sale of assets	4	0.53	—	—
Exploration and other expense	1	0.21	2	0.16
Taxes, other than income taxes	15	1.94	20	1.89
Total operating expenses	$ 249	$ 33.95	$ 398	$ 37.78
Total equivalent volumes (MBoe)	7,326		10,533	

	Nine months ended September 30,			
	2016		2015	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Operating expenses				
Oil and natural gas purchases	$ 9	$ 0.37	$ 24	$ 0.80
Transportation costs	81	3.32	82	2.78
Lease operating expense	117	4.78	139	4.67
General and administrative(2)	101	4.14	114	3.84
Depreciation, depletion and amortization	342	13.97	737	24.83
Gain on sale of assets	(78)	(3.20)	—	—
Exploration and other expense	3	0.13	14	0.48
Taxes, other than income taxes	43	1.73	65	2.19
Total operating expenses	$ 618	$ 25.24	$ 1,175	$ 39.59
Total equivalent volumes (MBoe)	24,483		29,671	

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

(2) For the quarter ended September 30, 2016, amount includes approximately $5 million or $0.72 per Boe of non-cash compensation expense. For the nine months ended September 30, 2016, amount includes approximately $10 million or $0.40 per Boe of transition and severance costs related to workforce reductions and $12 million or $0.49 per Boe of non-cash compensation expense. For the quarter ended September 30, 2015, amount includes approximately $5 million or $0.44 per Boe of non-cash compensation expense. For the nine months ended September 30, 2015, amount includes approximately $8 million or $0.26 per Boe of transition and severance costs related to workforce reductions and $8 million or $0.26 per Boe of non-cash compensation expense.

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Oil and natural gas purchases. We purchase and sell oil and natural gas on a monthly basis to improve the prices we would otherwise receive for our oil and natural gas or to manage firm transportation agreements. Oil and natural gas purchases for the quarter and nine months ended September 30, 2016 were $2 million and $9 million, respectively, compared to $9 million and $24 million for the same periods in 2015. For both the quarter and nine months ended September 30, 2016, natural gas purchases decreased following the sale of our Haynesville assets.
Lease operating expense. Lease operating expenses for the quarter and nine months ended September 30, 2016 were $37 million and $117 million, respectively, compared to $45 million and $139 million for the same periods in 2015. We experienced a decrease in lease operating expense in our three core areas for the quarter and nine months ended September 30, 2016. In Wolfcamp the decrease was approximately $2 million and $10 million, respectively, due to lower disposal costs, lower flowback and lower maintenance and repair costs. In Eagle Ford, the decrease was approximately $5 million and $6 million, respectively, due to lower flowback and lower disposal and chemical costs. In Altamont, lease operating expense remained flat for the quarter ended September 30, 2016 and decreased approximately $2 million for the nine months ended September 30, 2016 primarily due to lower disposal and chemical costs. During 2016, we have generally experienced a decrease in these costs across all programs due to ongoing contract negotiations with our service providers.

General and administrative expenses. General and administrative expenses for the quarter and nine months ended September 30, 2016 were $31 million and $101 million, respectively, compared to $32 million and $114 million for the same periods in 2015. Lower costs during the quarter and nine months ended September 30, 2016 compared to 2015 reflected lower payroll, benefits and administrative costs of $4 million and $14 million, respectively, partially offset by higher severance and other charges during 2016. Lower payroll, benefits and administrative costs resulted primarily from a general and administrative headcount reduction of approximately 15% in response to the lower commodity price environment and the sale of Haynesville.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the quarter and nine months ended September 30, 2016 was $132 million and $342 million, respectively, compared to $260 million and $737 million for the same periods in 2015. Our depreciation, depletion and amortization costs decreased in 2016 compared to the same period in 2015 due primarily to the impact of a non-cash impairment charge on our proved properties recorded in the fourth quarter of 2015, the sale of our Haynesville Shale assets in May 2016 and an overall decrease in production volumes. For the quarter and nine months ended September 30, 2016, our depreciation, depletion and amortization expense was also impacted by an adjustment of approximately $19 million ($2.58 per Boe for the quarter and $0.77 per Boe for the nine months) to accrue for certain non-income tax items that would have been historically capitalized and amortized or impaired in prior periods. Our average depreciation, depletion and amortization costs per unit for the quarters and nine months ended September 30 were:

	Quarter ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
Depreciation, depletion and amortization ($/Boe)	$17.97	$24.69	$13.97	$24.83

Our depreciation, depletion and amortization rate in the future will be impacted by the level and timing of capital spending, overall cost savings on capital and the level and type of reserves recorded on completed projects.

Gain on sale of assets. For the nine months ended September 30, 2016, we recorded a $79 million gain related to the sale of our assets in the Haynesville and Bossier shales completed in May 2016.

Exploration and other expense. For the quarter and nine months ended September 30, 2016, we recorded $1 million and $3 million, respectively, of exploration expense compared to $2 million and $14 million for the same periods in

2015. Included in exploration expense for both the quarter and nine months ended September 30, 2016, are approximately $1 million of amortization of unproved leasehold costs compared to $1 million and $9 million for the same periods in 2015. In addition, during the nine months ended September 30, 2015, we recorded approximately $2 million as other expense in conjunction with the early termination of a contract for drilling rigs during the first quarter of 2015.

Taxes, other than income taxes. Taxes, other than income taxes, for the quarter and nine months ended September 30, 2016 were $15 million and $43 million, respectively, compared to $20 million and $65 million for the same periods in 2015. Production taxes decreased in 2016 compared to the same period in 2015 due to lower oil volumes and the impact on severance taxes of lower commodity prices.

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Other Income Statement Items.

Gain (loss) on extinguishment of debt. During the quarter and nine months ended September 30, 2016, we paid approximately $47 million and $407 million, respectively, in cash to repurchase a total of approximately $75 million and $812 million, respectively, in aggregate principal amount of our senior unsecured notes and term loans. We recorded a gain on extinguishment of debt of approximately $26 million in the third quarter and $393 million year to date which included $1 million and $12 million, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs.

For the nine months ended September 30, 2016, we recorded losses on the extinguishment of debt of $9 million, primarily related to eliminating a portion of the unamortized debt issue costs due to the reduction of our RBL borrowing base in May 2016.

For the nine months ended September 30, 2015, we recorded $41 million ($12 million of which was non-cash) in losses on extinguishment of debt in conjunction with the early repayment and retirement of our $750 million senior secured notes due 2019.

Interest Expense. Interest expense for the quarter and nine months ended September 30, 2016 was $74 million and $231 million, respectively, compared to $84 million and $249 million for the same periods in 2015. Interest expense decreased in 2016 primarily due to the effects of our 2016 debt repurchases partially offset by higher interest expense related to our RBL Facility and higher interest expense related to our $580 million term loans due in 2021 issued in exchange for our existing term loans due in 2018 and 2019. The estimated annual interest savings from completed debt transactions in 2016 is approximately $30 million.

Income Taxes. For the quarter and nine months ended September 30, 2016, our effective tax rates were approximately 1%. Our effective tax rate differed from the statutory rate as a result of adjustments to the valuation allowance on our deferred tax assets which offset deferred income tax benefits by $16 million and deferred income tax expense by $43 million for the quarter and nine months ended September 30, 2016 (See Part I, Item 1, Financial Statements, Note 3). For the quarter and nine months ended September 30, 2015, our effective tax rates were 35% and 42%, respectively. Our effective tax rate for the nine months ended September 30, 2015 differs from the statutory rate primarily as a result of the effects of state income taxes (net of federal income tax effects) relative to our level of pre-tax book income (loss).

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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 net income (loss) 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 cash 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 costs that affect comparability, gains and losses on sales of assets and gains and losses on extinguishment of debt.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business without regard to financing methods and capital structure, (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), 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 consolidated net (loss) income to EBITDAX and Adjusted EBITDAX:

	Quarter ended September 30,		Nine months ended September 30,	
	2016	2015	2016	2015
	(in millions)			
Net (loss) income	$(43)	$176	$113	$(17)
Income tax expense (benefit)	1	95	1	(13)
Interest expense, net of capitalized interest	74	84	231	249
Depreciation, depletion and amortization	132	260	342	737
Exploration expense	1	2	3	12
EBITDAX	165	617	690	968
Mark-to-market on financial derivatives(1)	(43)	(434)	20	(458)
Cash settlements and cash premiums on financial derivatives(2)	145	258	514	649
Non-cash portion of compensation expense(3)	5	5	12	8
Transition, restructuring and other costs(4)	—	—	10	8
Loss (gain) on sale of assets	4	—	(78)	—
(Gain) loss on extinguishment of debt	(26)	—	(384)	41
Adjusted EBITDAX	$250	$446	$784	$1,216

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

(2) Represents actual cash settlements related to financial derivatives. No cash premiums were received or paid for the quarters or nine months ended September 30, 2016 and 2015.

(3) For the quarter and nine months ended September 30, 2016, cash payments were less than $1 million and approximately $3 million, respectively. For the quarter and nine months ended September 30, 2015, cash payments were less than $1 million and approximately $8 million, respectively.

(4) Reflects transition and severance costs related to workforce reductions.

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Commitments and Contingencies

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

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated by our operations and borrowings under our RBL Facility. Our primary uses of cash are capital expenditures, debt service including interest, and working capital requirements. Our available liquidity was approximately $803 million as of September 30, 2016.

During 2016, we have taken steps to improve our liquidity, strengthen our balance sheet and expand our financial flexibility, including (i) completing the sale of our Haynesville and Bossier shale assets for approximately $420 million (net proceeds of approximately $388 million after customary adjustments) in May 2016, (ii) repurchasing for cash a total of $812 million in aggregate principal amount of our unsecured notes and term loans for approximately $407 million in cash, (iii) amending certain restrictive debt covenants in our RBL Facility through the first quarter of 2018, (iv) exchanging approximately 95% of the outstanding amount of our term loans with a maturity date of May 2018 and April 2019 for an aggregate principal amount of new terms loans of approximately $580 million with amended terms and a maturity date of June 2021, and (v) entering into hedge transactions to provide additional 2016 and 2017 commodity price protection. The estimated annual interest savings from completed debt transactions in 2016 is approximately $30 million.

In May 2016, our RBL borrowing base was reduced to $1.65 billion, reflecting significantly lower bank commodity price forecasts, the sale of our Haynesville assets and the roll-off of certain hedge positions. In addition, we amended certain restrictive debt covenants for 2017 and through the first quarter of 2018, the most significant of which suspended the requirement that our debt to EBITDAX ratio, as defined in the credit agreement, not exceed 4.5 to 1.0 which was replaced with a requirement that our ratio of first lien debt to EBITDAX not exceed 3.5 to 1.0. The 4.5 to 1.0 debt to EBITDAX requirement will be reinstated beginning in April 2018. We also agreed to limit debt repurchases occurring after the redetermination to $350 million subject to certain future adjustments. Due to refinancing a significant portion of the outstanding balance of our 2018 and 2019 secured term loans in August 2016, the maturity of our RBL Facility will occur in May 2019. Prior to the refinancing transaction, our RBL maturity would have been in the fourth quarter of 2017.

Our RBL Facility has a borrowing base subject to semi-annual redetermination. The next redetermination date is in November 2016. We do not expect a reduction in our borrowing base as a result of this redetermination. Downward revisions of our oil and natural gas reserves volume and value due to declines in commodity prices, the impact of lower estimated capital spending in response to lower prices, performance revisions, or sales of assets, or the incurrence of certain types of additional debt, among other items, could cause a reduction of our borrowing base in the future, and these reductions could be significant.

For the remainder of 2016, we have derivative contracts providing us commodity price protection on a significant portion of our anticipated oil and natural gas production. These derivative contracts, which are fixed price swaps, allow us to realize a weighted average price of $80.77 per barrel on a remaining 4 MMBbls of oil and $3.34 on 6 TBtu of natural gas in 2016. We also have derivative contracts where we have effectively “locked-in” additional cash settlements on 0.2 MMBbls of oil in 2016. For 2017, we have derivative contracts on 13 MMBbls of our anticipated oil production at a weighted average price of $62.34 per barrel of oil. See "Our Business" for further information on our derivative instruments.

Based upon our actions to date, we believe our liquidity, and expected cash flows from operations will be sufficient to fund our capital program and meet current obligations and projected working capital requirements through the next twelve months.

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, or (iii) obtain additional capital if required on acceptable terms or at all to fund our capital programs or any potential future acquisitions, joint ventures or other similar transactions, will depend on prevailing economic conditions many of which are beyond our control. The extreme ongoing volatility in the energy industry and commodity prices will likely continue to impact our outlook. Our plans are intended to address the impacts of the current volatility in commodity prices while (i) maintaining sufficient liquidity to fund capital in our core drilling programs, (ii) meeting our debt maturities, and (iii) managing and working to strengthen our balance sheet. We continue to implement various cost saving measures to reduce our capital, operating, and general and administrative costs including renegotiating contracts with contractors, suppliers and service providers, reducing the number of staff and contractors and deferring and eliminating various discretionary costs. We will continue to be opportunistic and aggressive in managing our cost structure and in turn, our liquidity to meet our capital and operating needs.

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To the extent commodity prices remain low or decline further, or we experience disruptions in the financial markets impacting our longer-term access to or cost of capital, our ability to fund future growth projects may be further impacted. We continually monitor the capital markets and our capital structure and may make changes to our capital structure from time to time, with the goal of maintaining financial flexibility, preserving or improving liquidity and/or achieving cost efficiency. For example, we could (i) elect to continue to repurchase additional amounts of our outstanding debt in the future for cash through open market repurchases or privately negotiated transactions with certain of our debtholders subject to the limitation in our RBL Facility described previously or (ii) issue additional secured debt as permitted under our debt agreements, although there is no assurance we would do so. It is also possible additional adjustments to our plan and outlook may occur based on market conditions and the needs of the Company at that time, which could include selling additional assets, liquidating all or a portion of our hedge portfolio, seeking additional partners to develop our assets, issuing equity, and/or further reducing our planned capital program.

Capital Expenditures. For the full year 2016, we expect our capital expenditures will be approximately $495 million, exclusive of acquisition capital. Our capital expenditures and average drilling rigs by area for the nine months ended September 30, 2016 were:

	Capital Expenditures[(1)] (in millions)	Average Drilling Rigs
Eagle Ford Shale	$ 150	1.1
Wolfcamp Shale	161	0.6
Altamont	57	1.0
Haynesville Shale	4	—
Total	$ 372	2.7

(1) Represents accrual-based capital expenditures.

Debt. As of September 30, 2016, our total debt was approximately $3.9 billion, comprised of $2.4 billion in senior notes due in 2020, 2022 and 2023, $580 million in senior secured term loans due in 2021, $29 million in senior secured term loans with maturity dates in 2018 and 2019 and $870 million outstanding under the RBL Facility which matures in 2019. For additional details on our long-term debt, including maturities, borrowing capacity and restrictive covenants under our debt agreements, see above and Part I, Item 1, Financial Statements, Note 7.

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Overview of Cash Flow Activities. Our cash flows from operations are summarized as follows (in millions):

	Nine months ended September 30,	
	2016	2015
Cash Flow from Operations		
Operating activities		
Net income (loss)	$113	$(17)
Gain on sale of assets	(78)	—
(Gain) loss on extinguishment of debt	(384)	41
Other income adjustments	369	761
Changes in assets and liabilities	638	254
Total cash flow from operations	$658	$1,039
Other Cash Inflows		
Investing activities		
Proceeds from the sale of assets	$389	$—
	$389	$—
Financing activities		
Proceeds from issuance of long-term debt	630	1,777
Total cash inflows	$1,019	$1,777
Cash Outflows		
Investing activities		
Capital expenditures	$398	$1,203
Cash paid for acquisitions, net of cash acquired	—	114
	$398	$1,317
Financing activities		
Repayments and repurchases of long-term debt	1,239	1,473
Purchases of treasury stock	2	—
Other	24	20
	1,265	1,493
Total cash outflows	$1,663	$2,810
Net change in cash and cash equivalents	$14	$6

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Contractual Obligations

We are party to various contractual obligations. Some of these obligations are reflected in our financial statements, such as liabilities from financing obligations and commodity-based derivative contracts, while other obligations, such as operating leases and capital commitments, are not reflected on our balance sheet. The following table and discussion summarizes our contractual cash obligations as of September 30, 2016, for each of the periods presented:

	2016	2017- 2018	2019 - 2020	Thereafter	Total
			(in millions)		
Financing obligations:					
Principal	$—	$ 21	$ 2,454	$ 1,383	$3,858
Interest	73	582	432	147	1,234
Operating leases	3	22	—	—	25
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	17	130	119	99	365
Other obligations	13	45	1	—	59
Total contractual obligations	$106	$ 800	$ 3,006	$ 1,629	$5,541

Financing Obligations (Principal and Interest). Debt obligations included in the table above represent stated maturities. Interest payments are shown through the stated maturity date of the related debt based on (i) the contractual interest rate for fixed rate debt and (ii) current market interest rates and the contractual credit spread for variable rate debt. See Note 7 for more information on the maturities of our long-term debt.

Operating Leases. Amounts include leases related to our office space and various equipment.

Other Contractual Commitments and Purchase Obligations. Other contractual commitments and purchase obligations are legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum variable price provisions, and that detail approximate timing of the underlying obligations. Included are the following:

- Volume and Transportation Commitments. Included in these amounts are commitments for demand charges for firm access to natural gas transportation, volume deficiency contracts and firm oil capacity contracts.

- Other Obligations. Included in these amounts are commitments for drilling, completions and seismic activities for our operations and various other maintenance, engineering, procurement and construction contracts. Our future commitments under these contracts may change reflecting changes in commodity prices and any related effect on the supply/demand for these services. We have excluded asset retirement obligations and reserves for litigation and environmental remediation, as these liabilities are not contractually fixed as to timing and amount.

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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 2015 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 2015 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at September 30, 2016:

		Oil, Natural Gas and NGLs Derivatives			
		10 Percent Increase		10 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
	(in millions)				
Price impact[1]	$232	$164	$ (68)	$ 296	$ 64

		Oil, Natural Gas and NGLs Derivatives			
		1 Percent Increase		1 Percent Decrease	
	Fair Value	Fair Value	Change	Fair Value	Change
	(in millions)				
Discount rate[2]	$232	$231	$ (1)	$ 233	$ 1
Credit rate[3]	$232	$229	$ (3)	$ 233	$ 1

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

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

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of September 30, 2016, 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, 2016.

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 2016 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 2015 Annual Report on Form 10-K.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

The Exhibit Index is incorporated herein by reference.

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

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

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

SIGNATURES

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

	EP ENERGY CORPORATION
Date: October 27, 2016	/s/ Dane E. Whitehead Dane E. Whitehead Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Date: October 27, 2016	/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
10.1	Consent and Exchange Agreement, dated as of August 24, 2016, among EP Energy LLC, the other credit parties party thereto, the lenders party thereto, the additional lender party thereto, and Citibank, N.A. (Exhibit 10.1 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.2	Guarantee Agreement, dated as of August 24, 2016, among each Subsidiary of EP Energy LLC listed therein and Citibank, N.A., as collateral agent (Exhibit 10.2 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.3	Collateral Agreement, dated as of August 24, 2016, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as collateral agent (Exhibit 10.3 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.4	Pledge Agreement, dated as of August 24, 2016, among EP Energy LLC, each Subsidiary of EP Energy LLC identified therein and Citibank, N.A., as collateral agent (Exhibit 10.4 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.5	Amended and Restated Senior Lien Intercreditor Agreement, dated as of August 24, 2016, among JP Morgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent and Applicable Second Lien Agent, Citibank, N.A., as Priority Lien Term Facility Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.5 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
10.6	Priority Lien Intercreditor Agreement, dated as of August 24, 2016, among JP Morgan Chase Bank, N.A., as RBL Facility Agent and Applicable First Lien Agent, Citibank, N.A., as Term Facility Agent and Applicable Second Lien Agent, EP Energy LLC and the Subsidiaries of EP Energy LLC named therein (Exhibit 10.6 to Company's Current Report on Form 8-K, filed with the SEC on August 26, 2016).
*12.1	Ratio of Earnings to Fixed Charges
*31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document.
*101.SCH	XBRL Schema Document.

*101.CAL XBRL Calculation Linkbase Document.

*101.DEF XBRL Definition Linkbase Document.

*101.LAB XBRL Labels Linkbase Document.

*101.PRE XBRL Presentation Linkbase Document.