EP Energy Corp
Form 10-Q
August 03, 2017
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017
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	46-3472728
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
1001 Louisiana Street Houston, Texas	77002
(Address of Principal Executive Offices)	(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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer”, “accelerated filer”, “smaller reporting company” and "emerging growth 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

Emerging Growth Company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

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

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

Class A Common Stock, par value $0.01 per share. Shares outstanding as of July 24, 2017: 255,090,141

Class B Common Stock, par value $0.01 per share. Shares outstanding as of July 24, 2017: 705,179

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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
Mt. Belvieu	=Mont Belvieu natural gas liquids pricing index
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 2016 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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Operating revenues				
Oil	$202	$165	$406	$294
Natural gas	27	25	57	67
NGLs	22	15	45	26
Financial derivatives	45	(105)	115	(63)
Total operating revenues	296	100	623	324
Operating expenses				
Oil and natural gas purchases	1	3	2	7
Transportation costs	28	24	57	54
Lease operating expense	39	38	79	80
General and administrative	26	32	46	70
Depreciation, depletion and amortization	124	97	250	210
Gain on sale of assets	—	(82)	—	(82)
Impairment charges	1	—	1	—
Exploration and other expense	1	1	4	2
Taxes, other than income taxes	15	14	34	28
Total operating expenses	235	127	473	369
Operating income (loss)	61	(27)	150	(45)
Gain (loss) on extinguishment of debt	13	162	(40)	358
Interest expense	(82)	(73)	(165)	(157)
(Loss) income before income taxes	(8)	62	(55)	156
Income tax benefit	(5)	—	(5)	—
Net (loss) income	$(3)	$62	$(50)	$156
Basic net (loss) income per common share				
Net (loss) income	$(0.01)	$0.25	$(0.20)	$0.64
Basic weighted average common shares outstanding	246	245	246	244
Diluted net (loss) income per common share				
Net (loss) income	$(0.01)	$0.25	$(0.20)	$0.64
Diluted weighted average common shares outstanding	246	245	246	246

See accompanying notes.

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

	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$44	$ 20
Accounts receivable		
Customer, net of allowance of less than $1 in 2017 and 2016	126	133
Other, net of allowance of $1 in 2017 and 2016	40	16
Income tax receivable	5	—
Materials and supplies	14	16
Derivative instruments	87	58
Prepaid assets	4	5
Total current assets	320	248
Property, plant and equipment, at cost		
Oil and natural gas properties	7,465	7,194
Other property, plant and equipment	86	85
	7,551	7,279
Less accumulated depreciation, depletion and amortization	3,020	2,781
Total property, plant and equipment, net	4,531	4,498
Other assets		
Derivative instruments	27	4
Unamortized debt issue costs - revolving credit facility	9	10
Other	1	1
	37	15
Total assets	$4,888	$ 4,761

See accompanying notes.

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

	June 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$70	$ 63
Other	111	113
Derivative instruments	—	4
Accrued interest	65	43
Short-term debt, net of debt issue costs	121	—
Other accrued liabilities	93	98
Total current liabilities	460	321
Long-term debt, net of debt issue costs	3,825	3,789
Other long-term liabilities		
Derivative instruments	—	1
Asset retirement obligations	40	40
Other	4	4
Total non-current liabilities	3,869	3,834
Commitments and contingencies (Note 8)		
Stockholders' equity		
Class A shares, $0.01 par value; 550 million shares authorized; 255 million shares issued and outstanding at June 30, 2017; 251 million shares issued and outstanding at December 31, 2016	3	2
Class B shares, $0.01 par value; 0.7 million and 0.8 million shares authorized, issued and outstanding at June 30, 2017 and December 31, 2016	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Treasury stock (at cost); 0.7 million shares at June 30, 2017 and 0.5 million shares at December 31, 2016	(3)	(3)
Additional paid-in capital	3,549	3,546
Accumulated deficit	(2,990)	(2,939)
Total stockholders' equity	559	606
Total liabilities and equity	$4,888	$ 4,761

See accompanying notes.

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

	Six months ended June 30,	
	2017	2016
Cash flows from operating activities		
Net (loss) income	$(50)	$156
Adjustments to reconcile net (loss) income to net cash provided by operating activities		
Depreciation, depletion and amortization	250	210
Gain on sale of assets	—	(82)
Impairment charges	1	—
Loss (gain) on extinguishment of debt	40	(358)
Other non-cash income items	14	17
Asset and liability changes		
Accounts receivable	(17)	88
Accounts payable	(7)	(32)
Derivative instruments	(57)	434
Accrued interest	22	(10)
Other asset changes	(3)	4
Other liability changes	(12)	(21)
Net cash provided by operating activities	181	406
Cash flows from investing activities		
Cash paid for capital expenditures	(266)	(258)
Proceeds from the sale of assets	—	390
Net cash (used in) provided by investing activities	(266)	132
Cash flows from financing activities		
Proceeds from issuance of long-term debt	1,385	575
Repayments and repurchases of long-term debt	(1,253)	(1,097)
Debt issue costs	(20)	(1)
Other	(3)	(2)
Net cash provided by (used in) financing activities	109	(525)
Change in cash and cash equivalents	24	13
Cash and cash equivalents		
Beginning of period	20	26
End of period	$44	$39

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	
	Shares	Amount	Shares	Amount	Stock	Capital	Deficit	Total
Balance at December 31, 2016	251	$ 2	0.8	$ —	$ (3)	$ 3,546	$ (2,939)	$606
Cumulative effect of accounting change	—	—	—	—	—	1	(1)	—
Balance at January 1, 2017	251	$ 2	0.8	$ —	$ (3)	$ 3,547	$ (2,940)	$606
Share-based compensation	4	1	(0.1)	—	—	2	—	3
Net loss	—	—	—	—	—	—	(50)	(50)
Balance at June 30, 2017	255	$ 3	0.7	$ —	$ (3)	$ 3,549	$ (2,990)	$559

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 2016 Annual Report on
Form 10-K. The condensed consolidated financial statements as of June 30, 2017 and 2016 are unaudited. The consolidated balance sheet as of December 31, 2016 has been derived from the audited consolidated balance sheet included in our 2016 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 2016 Annual Report on Form 10-K other than in Accounting for Long-Term Incentive Compensation. In the first quarter of 2017, we adopted Accounting Standards Update (ASU) No. 2016-09, Improvements to Employee Share-Based Payment Accounting which simplifies several aspects of the accounting for share-based payment awards to employees including accounting for income taxes, forfeitures, statutory tax withholding requirements and classification in the statement of cash flows. As permitted under ASU 2016-09, we have elected to account for forfeitures in compensation cost when they occur. Upon adoption of the ASU, we recorded a cumulative adjustment of approximately $1 million to the opening balance of retained earnings as of January 1, 2017.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standards have been issued but not yet adopted as of June 30, 2017.

Statement of Cash Flows. In August 2016, the Financial Accounting Standards Board (FASB) issued 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. In November 2016, the FASB issued ASU No. 2016-18, Statement of Cash Flows - Restricted Cash, which requires restricted cash and restricted cash equivalents to be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts shown on the statement of cash flows. Retrospective application of these standards is required for fiscal years 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.

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 continue to evaluate our contracts and other agreements to assess 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. Adoption of this standard is required beginning in the first quarter of 2018, with
the option of early adoption in 2017. Modified or full retrospective application of this standard is required upon adoption. Based upon our preliminary contract evaluations, we do not anticipate our adoption of this standard in 2018, utilizing the modified retrospective approach, will have a material impact on our financial statements. We continue to evaluate disclosure requirements and assess any potential changes to our accounting policies, business processes and/or controls as a result of the provisions of this standard.

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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 $390 million after customary adjustments). We recorded a gain on the sale of approximately $83 million, with the buyer also assuming a transportation commitment totaling $106 million.

Summarized operating results of our assets sold were as follows (in millions):

	Quarter ended June 30, 2016	Six months ended June 30, 2016
Operating revenues	$ 6	$ 26
Operating expenses		
Transportation costs	2	7
Lease operating expense	—	1
Depreciation, depletion and amortization	—	16
Other expense	1	5
Total operating expenses	3	29
Gain on sale of assets	83	83
Income before income taxes	$ 86	$ 80

3. Income Taxes

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 six months ended June 30, 2017 our effective tax rates were approximately 59% and 8%, respectively. For both the quarter and six months ended June 30, 2016, our effective tax rates were 0%. Our effective tax rates in 2017 and 2016 differed from the statutory rate primarily as a result of our recognition of a full valuation allowance on our deferred tax assets. For the quarters ended June 30, 2017 and 2016 we recorded adjustments to the valuation allowance on our deferred tax assets which offset deferred income tax expense of $3 million and $24 million, respectively, and offset deferred income tax benefit and deferred income tax expense of $12 million and $59 million for the six months ended June 30, 2017 and 2016, respectively. Our effective tax rate for both the quarter and six months ended June 30, 2017 also reflects recording a current income tax receivable and income tax benefit for the recovery of previously paid alternative minimum taxes based on our 2016 depreciation election.

We evaluate the realization of our deferred tax assets and record any associated 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 $996 million as of June 30, 2017.

The Company's and certain subsidiaries' income tax years (2014-2016) remain open and subject to examination by both federal and state tax authorities. During the second quarter of 2017, we concluded an examination of our 2013 U.S. tax return.

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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 unit awards. For the quarter and six months ended June 30, 2017, we incurred a net loss 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. For the quarter and six months ended June 30, 2016, approximately 0.03 million and 1.9 million shares, respectively, are included in our calculation of diluted earnings per share related to our restricted stock awards and performance units (see Note 9).

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 June 30, 2017 and December 31, 2016, all of our 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:

	June 30, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Short-term debt	$122	$92	$—	$—
Long-term debt (see Note 7)	$3,877	$3,034	$3,856	$3,637
Derivative instruments	$114	$114	$57	$57

As of June 30, 2017 and December 31, 2016, 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, considering 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 June 30, 2017, we had derivative contracts in the form of fixed price swaps and three-way collars on 14 MMBbls of oil (5 MMBbls in 2017 and 9 MMBbls in 2018). In addition to our oil derivatives, we had derivative contracts in the form of fixed price swaps and options on 50 TBtu of natural gas (17 TBtu in 2017, 26 TBtu in 2018 and 7 TBtu in 2019) and 112 MMGal of ethane and propane fixed price swaps (50 MMGal in 2017 and 62 MMGal in 2018). As of December 31, 2016, we had fixed price derivative contracts for 16 MMBbls of oil, 36 TBtu on natural gas and 108 MMGal on ethane. In addition to the contracts above, we have derivative contracts related to locational basis differences on our oil and natural gas 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 June 30, 2017 and December 31, 2016. 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 consolidated balance sheets as either current or non-current assets or liabilities based on their anticipated settlement date, net of the impact of master netting agreements. On derivative contracts recorded as assets in the table below, we are exposed to the risk that our counterparties may not perform.

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	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)			
June 30, 2017								
Derivative instruments	$120	$ (6)	$ 87	$ 27	$(6)	$ 6	$ —	$ —
December 31, 2016								
Derivative instruments	$79	$ (17)	$ 58	$ 4	$(22)	$ 17	$ (4)	$ (1)

For the quarters ended June 30, 2017 and 2016, we recorded a derivative gain of $45 million and a derivative loss of $105 million, respectively. For the six months ended June 30, 2017 and 2016, we recorded a derivative gain of $115 million and a derivative loss of $63 million, respectively. Derivative gains and losses on our oil, natural gas and NGLs financial derivative instruments are recorded in operating revenues in our consolidated income statements.

6. Property, Plant and Equipment

Oil and Natural Gas Properties. As of both June 30, 2017 and December 31, 2016, we had approximately $4.5 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:

	June 30, 2017	December 31, 2016
	(in millions)	
Proved		
Eagle Ford	$3,118	$ 3,001
Wolfcamp	2,571	2,415
Altamont	1,665	1,624
Total Proved	7,354	7,040
Unproved		
Wolfcamp	50	94
Altamont	61	60
Total Unproved	111	154
Less accumulated depletion	2,964	2,731
Net capitalized costs for oil and natural gas	$4,501	$ 4,463

properties
During the six months ended June 30, 2017, we transferred approximately $46 million from unproved properties to proved properties. For the quarters ended June 30, 2017 and 2016, we recorded approximately $1 million and less than $1 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statements. For the six months ended June 30, 2017 and 2016, we recorded approximately $2 million and less than $1 million, respectively, of amortization of unproved leasehold costs. Suspended well costs were not material as of June 30, 2017 or December 31, 2016.

We evaluate capitalized costs related to proved properties upon a triggering event (such as a significant and sustained decline in forward commodity prices) to determine if an 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 upon a triggering event for impairment based on estimated drilling plans and capital expenditures which may also change based on forward commodity price changes 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.

Generally, economic recovery of unproved reserves in non-producing or unproved areas is not yet supported by actual production or conclusive formation tests, but may be confirmed by continuing exploration and development activities. Our

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ability to retain our leases and thus recover our non-producing leasehold costs is 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 commodity prices not justify sufficient capital allocation to the continued development of properties where we have non-producing leasehold costs, we could incur impairment charges of our unproved property costs.

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 and 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 primarily 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 changing market conditions. The net asset retirement liability as of June 30, 2017 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability from January 1 through June 30, 2017 were as follows:

	2017
	(in millions)
Net asset retirement liability at January 1	$ 41
Liabilities settled	(1)
Accretion expense	2
Net asset retirement liability at June 30	$ 42

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 six months ended June 30, 2017 was approximately $1 million and $2 million, respectively. Capitalized interest for the quarter and six months ended June 30, 2016 was less than $1 million and approximately $2 million, respectively.

7. Long-Term Debt

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

	Interest Rate	June 30, 2017	December 31, 2016
		(in millions)	
RBL credit facility - due May 24, 2019(1)	Variable	$400	$ 370
Senior secured term loans:			
Due May 24, 2018(2)(4)	Variable	21	21
Due April 30, 2019(3)(4)	Variable	8	8
Due June 30, 2021(5)	Variable	—	580
Senior secured notes:			
Due November 29, 2024	8.00%	500	500
Due February 15, 2025	8.00%	1,000	—
Senior unsecured notes:			
Due May 1, 2020	9.375%	1,269	1,576
Due September 1, 2022	7.75%	250	250
Due June 15, 2023	6.375%	551	551

Total debt	3,999	3,856
Less short-term debt, net of debt issue costs of $1 million	(121)	—
Total long-term debt	3,878	3,856
Less non-current portion of unamortized debt issue costs	(53)	(67)
Total long-term debt, net	$3,825	$ 3,789

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(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 June 30, 2017 and December 31, 2016, the effective interest rate of the term loan was 3.80% and 3.50%, respectively.

(3) Carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of June 30, 2017 and December 31, 2016, the effective interest rate for the term loan was 4.55% and 4.50%, respectively.

(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) As of December 31, 2016, the effective interest rate for the term loan was 9.75%.

In June 2017, we paid approximately $42 million in cash to repurchase a total of approximately $56 million in aggregate principal amount of our senior unsecured notes due 2020. In connection with these repurchases, we recorded a gain on extinguishment of debt of approximately $13 million (including $1 million of non-cash expense related to eliminating associated unamortized debt issue costs). Subsequent to June 30, 2017, we repurchased an additional $101 million in aggregate principal amount of our senior unsecured notes due 2020 and 2023 for approximately $76 million in cash. We classified the principal amount of this additional long-term debt repurchased subsequent to June 30, 2017 as short-term debt on our consolidated balance sheet as of June 30, 2017.

During the first quarter of 2017, we issued $1 billion of 8.00% senior secured notes which mature in 2025 and used the proceeds (less fees and expenses) to (i) repay in full our $580 million senior secured term loans due 2021, (ii) repurchase $250 million in aggregate principal amount of our 9.375% senior unsecured notes due 2020 and (iii) repay $111 million of the amounts outstanding under our Reserve-Based Loan facility (RBL Facility). As a result of the issuance, our RBL Facility borrowing base was also reduced to $1.44 billion. In conjunction with these transactions, we recorded a loss on extinguishment of debt of approximately $53 million (including $30 million in non-cash expense related to eliminating associated unamortized debt issue costs and debt discounts).

During the six months ended June 30, 2016, we paid approximately $360 million in cash to repurchase a total of approximately $737 million in aggregate principal amount of our senior unsecured notes and term loans which resulted in a gain on extinguishment of debt of approximately $170 million and $366 million for the quarter and six months ended June 30, 2016 (including $5 million and $11 million, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs). For both the quarter and six months ended June 30, 2016, we also recorded a loss on extinguishment of debt of approximately $8 million related to eliminating a portion of the unamortized debt issue costs due to the reduction of our RBL borrowing base in May 2016.

Unamortized Debt Issue Costs. As of June 30, 2017 and December 31, 2016, we had total unamortized debt issue costs of $62 million and $77 million. Of these amounts, $9 million and $10 million, respectively, are associated with our RBL Facility and $53 million and $67 million, respectively, are associated with our senior secured term loans and senior notes. During the six months ended June 30, 2017, we (i) recorded an additional $20 million ($19 million in conjunction with the issuance of our $1 billion of 8.00% senior secured notes and $1 million in conjunction with the RBL Facility semi-annual redetermination) and (ii) expensed approximately $28 million in conjunction with the repurchase of a portion of our senior secured term loans and senior unsecured notes and the reduction of our RBL Facility borrowing base. During the quarters ended June 30, 2017 and 2016, we amortized $3 million and $4 million, respectively, of deferred financing costs into interest expense. For the six months ended June 30, 2017 and 2016, amortization of deferred financing costs was $7 million and $8 million, respectively.

Reserve-based Loan Facility. We have a $1.44 billion credit facility in place which allows us to borrow funds or issue letters of credit. The facility matures in May 2019. As of June 30, 2017, we had $1,018 million of available capacity remaining with approximately $19 million of letters of credit issued and approximately $400 million outstanding under the facility.

The RBL Facility is collateralized by certain of our oil and natural gas properties and has a borrowing base subject to semi-annual redetermination. In April 2017, we completed the semi-annual redetermination and reaffirmed the borrowing base at $1.44 billion. Our next redetermination date is in October 2017. Downward revisions of our oil and natural gas reserves due to declines in commodity prices, performance revisions, 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.

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. In conjunction with the redetermination of our RBL Facility in April 2017, we extended our first lien debt to EBITDAX covenant through March 31, 2019. In addition, the first lien debt to EBITDAX ratio, as defined in the credit agreement, was reduced to 3.0 to 1.0. As of June 30, 2017, we were in compliance with our debt covenants, and our ratio of first lien debt to EBITDAX was 0.47x. In April 2019, our financial covenant will revert to a requirement that our total debt to EBITDAX ratio not exceed 4.5 to 1.0.

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Under our RBL Facility, we are also limited in non-RBL Facility debt repurchases to $350 million, subject to certain adjustments. As of July 31, 2017, the non-RBL Facility debt repurchases limit was approximately $900 million as a result of recent divestitures and financing transactions and will continue to be subject to future adjustments. Certain other covenants and restrictions, among other things, also limit or place certain conditions on our ability to incur or guarantee additional indebtedness; make any restricted payments or pay any dividends on equity interests or redeem, repurchase or retire equity interests or subordinated indebtedness; sell assets; make investments; create certain liens; prepay debt obligations; engage in transactions with affiliates; and enter into certain hedge agreements.

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 June 30, 2017, we had approximately $4 million accrued for all outstanding legal matters.

FairfieldNodal v. EP Energy E&P Company, L.P. In 2014, Fairfield filed suit against one of our subsidiaries in a Texas district court, claiming we were contractually obligated to pay a transfer fee of approximately $21 million for seismic licensing, triggered by a change in control with the Sponsors' acquisition of our predecessor entity in 2012. Prior to the change in control, we had unilaterally terminated the seismic licensing agreements, and we returned the applicable seismic data. Fairfield also claimed EP Energy did not properly maintain the confidentiality of the seismic data and interpretations made from it. In April 2015, the district court granted summary judgment to EP Energy, and Fairfield then appealed. On July 6, 2017, an intermediate court of appeals in Texas reversed the judgment related to the transfer fee. We intend to appeal this court's ruling to the Texas Supreme Court. At this time, we are unable to estimate the amount or range of possible loss, if any, on this matter.

Indemnifications and Other Matters. We periodically enter into indemnification arrangements as part of the divestiture 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 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 all, or a portion of the plugging or abandonment obligations on assets we no longer own or operate. As of June 30, 2017, we had approximately $8 million accrued related to these indemnifications and other matters.

Non-Income Tax Matters. We are under a number of examinations by taxing authorities related to non-income tax matters. As of June 30, 2017, we had approximately $48 million accrued (in other accrued liabilities in our consolidated balance sheet) in connection with ongoing examinations related to certain prior period non-income tax 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. 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. For additional details on certain environmental matters, including matters related to climate change, air quality and other emissions, hydraulic fracturing regulations and waste handling, refer to the Risk Factors section of our 2016 Annual Report on Form 10-K.

While our reserves for environmental matters are currently not material, there are still uncertainties related to the ultimate costs we may incur in the future in order to comply with 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. Based upon our evaluation and experience to date, however, we believe

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our accruals for these matters are adequate. It is possible that new information or future developments could result in substantial additional costs and liabilities which could require us to reassess our potential exposure related to these matters and to adjust our accruals accordingly, and these adjustments could be material.

9. Long-Term Incentive Compensation

Restricted Stock. Our long-term incentive (LTI) programs consist of restricted stock, stock options and performance unit awards. A summary of the changes in our non-vested restricted shares for the six months ended June 30, 2017 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2016	6,326,788	$ 7.69
Granted	5,100,511	$ 4.29
Vested	(2,139,233)	$ 8.28
Forfeited	(596,633)	$ 7.45
Non-vested at June 30, 2017	8,691,433	$ 5.56

Performance Unit Awards. A summary of the changes in our performance unit awards for the six months ended June 30, 2017 is presented below:

	Number of Awards	Weighted Average Fair Value
Non-vested at December 31, 2016	78,900	$ 97.77
Granted[(1)]	40,470	$ 36.57
Vested	(22,302)	$ 159.92
Forfeited	(12,000)	$ 159.92
Non-vested at June 30, 2017	85,068	$ 70.63

(1) Grant date fair value at March 16, 2017 is based on: (i) an expected term of 3 years, (ii) expected volatility of 96.71%, which is based upon the historical stock price volatility and (iii) a risk-free interest rate of 1.57%, based upon the yield on U.S. Treasury STRIPS over the expected term as of the grant date.

Our performance unit awards are treated as liability awards for accounting purposes with the expense recognized on an accelerated basis and fair value remeasured at each reporting period. During the six months ended June 30, 2017, we paid approximately $4 million in connection with awards that vested and had accrued approximately $2 million related to unvested outstanding performance unit awards. Performance unit awards may be settled in either stock or cash at the election of the board of directors. Had all outstanding performance unit awards at June 30, 2017 vested and been settled in stock, two million shares would have been issued. Refer to our 2016 Annual Report on Form 10-K for further description regarding the terms and details of these awards.

We record compensation expense on all of our LTI awards as general and administrative expense over the requisite service period. Pre-tax compensation expense related to all of our LTI awards (both equity and liability based), net of the impact of forfeitures, was approximately $6 million and $5 million for the quarters ended June 30, 2017 and 2016, respectively, and $5 million and $10 million for the six months ended June 30, 2017 and 2016. Included in pre-tax compensation expense for the six months ended June 30, 2017 was approximately $7 million of forfeitures recorded during the quarter ended March 31, 2017. As of June 30, 2017, we had unrecognized compensation expense of $57 million. We will recognize an additional $12 million related to our outstanding awards during the remainder of 2017, $33 million over the remaining requisite service periods subsequent to 2017 and $12 million should a specified capital transaction occur and the right to such amounts become non-forfeitable.

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10. Related Party Transactions

Joint Venture. In January 2017, we entered into a drilling joint venture with Wolfcamp Drillco Operating L.P. (the Investor), which is managed and controlled by an affiliate of Apollo Global Management LLC, to fund future oil and natural gas development in our Wolfcamp program. Subsequently, Access Industries acquired an indirect minority ownership interest in the Investor and therefore is also indirectly responsible for funding a portion of the Investor's capital commitment. The Investor is anticipated to fund approximately $450 million over the entire program (150 wells in two separate 75 well tranches), or approximately 60 percent of the estimated drilling, completion and equipping costs of the wells in exchange for a 50 percent working interest in the joint venture wells. Once the Investor achieves a 12 percent internal rate of return on its invested capital in each tranche, its working interest reverts to 15 percent. We are the operator of the joint venture assets and the transaction increases our well-level returns on the jointly developed wells. The first wells under the joint venture began producing in January 2017, and for the six months ended June 30, 2017, we recovered approximately $127 million related to the capital costs of the joint venture wells from the Investor.

Affiliate Supply Agreement. For the six months ended June 30, 2017 and 2016, we recorded less than $1 million and approximately $5 million in capital expenditures for amounts expended under supply agreements entered into with an affiliate of Apollo Global Management, LLC to provide certain materials used in our Eagle Ford drilling operations.

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

Our Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") should be read in conjunction with the financial statements and the accompanying notes presented in Item 1 of Part I of this Quarterly Report on Form 10-Q. This discussion contains forward-looking statements and involves numerous risks and uncertainties, including, but not limited to, those described in the "Risk Factors" section of our 2016 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 operate through a diverse base of producing
assets and are focused on creating shareholder value through the development of our drilling inventory located in three core areas: the Wolfcamp Shale (Permian Basin in West Texas), the Eagle Ford Shale (South Texas), and the Altamont Field in the Uinta Basin (Northeastern Utah).

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 also sell oil and natural gas properties if they no longer meet our long-term goals.

From time to time, we will also enter into joint ventures to enhance the development, hold acreage and/or improve near-term economics in our programs. In January and May 2017, we entered into drilling joint ventures in our Wolfcamp and Altamont programs. In Wolfcamp, our partner is participating in the development of up to 150 wells in two separate 75 well tranches primarily in Reagan and Crockett counties. Our joint venture investor will fund approximately $450 million over the entire program, or approximately 60 percent of the estimated drilling, completion and equipping costs of the wells in exchange for a 50 percent working interest in the joint venture wells. The first wells under the joint venture began producing in January 2017. In Altamont, our partner is participating in the development of 60 wells and will provide a capital carry in exchange for 50 percent working interest in the joint venture wells. The first wells under the joint venture began producing in July 2017. We are the operator of the assets in both joint ventures.

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.

Forward commodity prices play a significant role in determining the recoverability of proved or unproved property costs on our balance sheet. Future price declines, along with changes to our future capital, production rates, levels of proved reserves and development plans, may result in an impairment of the carrying value of our proved and/or unproved properties in the future, and such charges could be significant.

Derivative Instruments. Our realized prices from the sale of our oil, natural gas and NGLs are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell the commodity, 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 unfavorable movements in locational prices. 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. 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.

During the six months ended June 30, 2017, we (i) settled commodity index hedges on approximately 68% of our oil production, 58% of our total liquids production and on 64% of our natural gas production at average floor prices of $61.28 per barrel of oil, $0.45 per gallon of NGLs and $3.27 per MMBtu of natural gas, respectively. To the extent our oil and natural gas production is unhedged, either from a commodity index or locational price perspective, our operating revenues 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 June 30, 2017.

	2017		2018		2019	
	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]
Oil						
Fixed Price Swaps						
WTI	552	$58.05	—	$—	—	$—
Three Way Collars						
Ceiling - WTI	4,453	$70.37	8,859	$68.15	—	$—
Floors - WTI[2][3]	4,453	$60.62	8,859	$60.00	—	$—
Basis Swaps						
LLS vs. Brent[4]	1,840	$(3.14)	—	$—	—	$—
Midland vs. Cushing[5]	1,288	$(0.81)	2,190	$(1.10)	—	$—
Natural Gas						
Fixed Price Swaps	12	$3.25	26	$3.04	7	$2.97
Ceiling	5	$3.67	—	$—	—	$—
Floors	5	$3.35	—	$—	—	$—
Basis Swaps						
WAHA vs. Henry Hub[6]	7	$(0.34)	15	$(0.46)	7	$(0.39)
NGLs						
Fixed Price Swaps - Ethane	31	$0.27	62	$0.30	—	$—
Fixed Price Swaps - Propane	19	$0.67	—	$—	—	$—

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

(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) If market prices settle at or below $50.00 in 2018, we will receive a "locked-in" cash settlement of the market price plus $10.00 per Bbl.

(4) EP Energy receives Brent plus the basis spread listed and pays LLS. These positions listed do not include offsetting LLS vs. Brent basis swaps on our 1.84 MBbls LLS vs. Brent with an average of $(0.46) per barrel of oil.

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

(6) EP Energy receives Henry Hub plus the basis spread listed and pays WAHA.

For the period from July 1, 2017 through August 1, 2017, we entered into derivative contracts on 0.4 MMBbls of 2018 Midland vs. Cushing basis swaps and 0.1 MMBls of 2017 LLS vs. WTI basis swaps.

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Summary of Liquidity and Capital Resources. As of June 30, 2017, we had available liquidity of approximately $1,062 million, reflecting $1,018 million of available liquidity on our $1.44 billion Reserve-Based Loan facility (RBL Facility) borrowing base and $44 million of available cash. In 2017, we continued to take steps to improve our liquidity, strengthen our balance sheet and expand our financial flexibility. These steps included (i) issuing $1 billion of 8.00% senior secured notes which mature in 2025 and using the net proceeds to repay in full our senior secured term loans, repurchase certain of our senior notes, and repay a portion of the amounts outstanding under our RBL Facility and (ii) repurchasing for cash a total of $157 million in aggregate principal amount ($56 million repurchased as of June 30, 2017) of our senior unsecured notes due 2020 and 2023 for approximately $118 million ($42 million as of June 30, 2017). In addition, in April 2017, we reaffirmed the borrowing base of our RBL Facility at $1.44 billion and amended our credit agreement, extending the first lien debt to EBITDAX covenant through March 31, 2019, and reducing it such that the ratio of first lien debt to EBITDAX may not exceed 3.0 to 1.0. For a further discussion of our liquidity and capital resources, including factors that could impact our liquidity, see Liquidity and Capital Resources.

Outlook. For the full year 2017, we expect to spend approximately $550 million to $600 million in capital in our programs, with $250 million to $300 million allocated to the Wolfcamp Shale, approximately $200 million allocated to the Eagle Ford Shale and approximately $100 million allocated to Altamont. We anticipate 160 to 180 gross well completions, and our average daily production volumes for the year to be approximately 80 MBoe/d to 85 MBoe/d, including average daily oil production volumes of approximately 46 MBbls/d to 48 MBbls/d.

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Production Volumes and Drilling Summary

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

	2017	2016
Equivalent Volumes (MBoe/d)		
Wolfcamp Shale	26.4	18.0
Eagle Ford Shale	39.6	47.9
Altamont	17.7	15.9
Other[(1)]	—	12.5
Total	83.7	94.3
Oil (MBbls/d)	48.0	47.9
Natural Gas (MMcf/d)[(1)]	126	193
NGLs (MBbls/d)	14.8	14.2

(1) Primarily consists of Haynesville Shale which was sold in May 2016. For the six months ended June 30, 2016, natural gas volumes included 75 MMcf/d from the Haynesville Shale.

- Wolfcamp Shale—Our Wolfcamp Shale equivalent volumes increased 8.4 MBoe/d (approximately 47%) and oil production increased by 3.6 MBbls/d (approximately 52%) for the six months ended June 30, 2017 compared to the same period in 2016. During the six months ended June 30, 2017, we completed 32 additional operated wells, for a total of 303 net operated wells as of June 30, 2017.

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes decreased by 8.3 MBoe/d (approximately 17%) and oil production decreased by 4.6 MBbls/d (approximately 15%) for the six months ended June 30, 2017 compared to the same period in 2016. During the six months ended June 30, 2017, we completed 39 additional operated wells in the Eagle Ford, for a total of 636 net operated wells as of June 30, 2017.

- Altamont—Our Altamont equivalent volumes increased 1.8 MBoe/d (approximately 11%) and oil production increased by 1.1 MBbls/d (approximately 10%) for the six months ended June 30, 2017 compared to the same period in 2016. During the six months ended June 30, 2017, we completed eight additional operated oil wells, for a total of 378 net operated wells as of June 30, 2017.

Our production declines in our Eagle Ford area reflect natural declines and the slowed pace of development in our drilling program due to reduced capital spending in 2016, while increases in Wolfcamp reflect incremental capital allocated to this program in 2016. Future volumes across all our assets will be impacted by the level of natural declines, and the level and timing of capital spending in each respective asset. In the current commodity price environment, we may continue to have low spending levels which may result in lower produced 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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Operating revenues				
Oil	$202	$165	$406	$294
Natural gas	27	25	57	67
NGLs	22	15	45	26
Total physical sales	251	205	508	387
Financial derivatives	45	(105)	115	(63)
Total operating revenues	296	100	623	324
Operating expenses				
Oil and natural gas purchases	1	3	2	7
Transportation costs	28	24	57	54
Lease operating expense	39	38	79	80
General and administrative	26	32	46	70
Depreciation, depletion and amortization	124	97	250	210
Gain on sale of assets	—	(82)	—	(82)
Impairment charges	1	—	1	—
Exploration and other expense	1	1	4	2
Taxes, other than income taxes	15	14	34	28
Total operating expenses	235	127	473	369
Operating income (loss)	61	(27)	150	(45)
Gain (loss) on extinguishment of debt	13	162	(40)	358
Interest expense	(82)	(73)	(165)	(157)
(Loss) income before income taxes	(8)	62	(55)	156
Income tax benefit	(5)	—	(5)	—
Net (loss) income	$(3)	$62	$(50)	$156

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters and six months ended June 30, 2017 and 2016. 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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Operating revenues:				
Oil	$202	$165	$406	$294
Natural gas	27	25	57	67
NGLs	22	15	45	26
Total physical sales	251	205	508	387
Financial derivatives	45	(105)	115	(63)
Total operating revenues	$296	$100	$623	$324
Volumes:				
Oil (MBbls)	4,452	4,100	8,671	8,724
Natural gas (MMcf)(1)	11,353	13,954	22,818	35,104
NGLs (MBbls)	1,386	1,265	2,682	2,582
Equivalent volumes (MBoe)(1)	7,730	7,691	15,156	17,157
Total MBoe/d(1)	84.9	84.5	83.7	94.3
Prices per unit(2):				
Oil				
Average realized price on physical sales ($/Bbl)(3)	$45.27	$40.13	$46.81	$33.64
Average realized price, including financial derivatives ($/Bbl)(3)(4)	$51.83	$77.45	$53.33	$74.95
Natural gas				
Average realized price on physical sales ($/Mcf)(3)	$2.40	$1.60	$2.45	$1.73
Average realized price, including financial derivatives ($/Mcf)(3)(4)	$2.49	$1.90	$2.48	$1.95
NGLs				
Average realized price on physical sales ($/Bbl)	$16.00	$11.90	$16.79	$10.03
Average realized price, including financial derivatives ($/Bbl)(4)	$16.56	$12.06	$17.14	$10.34

(1) For the quarter ended June 30, 2016, Haynesville Shale production volumes were 3,437 MMcf of natural gas and 573 MBoe (6.3 MBoe/d) of equivalent volumes. For the six months ended June 30, 2016, Haynesville Shale production volumes were 13,563 MMcf of natural gas and 2,260 MBoe (12.4 MBoe/d) of equivalent volumes.

(2) Natural gas prices for the quarter and six months ended June 30, 2017 reflect operating revenues for natural gas reduced by approximately $1 million and $2 million, respectively, for natural gas purchases associated with managing our physical sales. Natural gas prices for the quarter and six months ended June 30, 2016 reflect operating revenues for natural gas reduced by approximately $3 million and $7 million, respectively, for natural gas purchases associated with managing our physical sales. Oil prices for the quarter and six months ended June 30, 2016 reflect operating revenues for oil reduced by less than $1 million and approximately $1 million, respectively, for oil purchases associated with managing our physical sales.

(3)

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.

(4) The quarters ended June 30, 2017 and 2016, include approximately $30 million and $153 million, respectively, of cash received for the settlement of crude oil derivative contracts and approximately $1 million and $4 million of cash received, respectively, for the settlement of natural gas financial derivatives. The six months ended June 30, 2017 and 2016, include approximately $57 million and $360 million, respectively, of cash received for the settlement of crude oil derivative contracts and approximately $1 million and $8 million of cash received, respectively, for the settlement of natural gas financial derivatives. The quarters ended June 30, 2017 and 2016 each include less than $1 million of cash received for the settlement of NGLs derivative contracts. The six months ended June 30, 2017 and 2016, each include approximately $1 million of cash received for the settlement of NGLs derivative contracts.

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Physical sales. Physical sales represent accrual-based commodity sales transactions with customers. For the quarter and six months ended June 30, 2017, physical sales increased by $46 million (22%) and $121 million (31%), respectively, compared to the same periods in 2016. Physical sales have increased primarily due to higher prices across all commodity types, partially offset by lower natural gas volumes as a result of the sale of our Haynesville Shale assets in May 2016. The table below displays the price and volume variances on our physical sales when comparing the quarter and six months ended June 30, 2017 and 2016.

	Quarter ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
June 30, 2016 sales	$165	$ 25	$ 15	$205
Change due to prices	23	8	6	37
Change due to volumes	14	(6)	1	9
June 30, 2017 sales	$202	$ 27	$ 22	$251

	Six months ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
June 30, 2016 sales	$294	$ 67	$ 26	$387
Change due to prices	114	14	18	146
Change due to volumes	(2)	(24)	1	(25)
June 30, 2017 sales	$406	$ 57	$ 45	$508

Oil sales for the quarter and six months ended June 30, 2017, compared to the same periods in 2016, increased by $37 million (22%) and $112 million (38%), respectively, due primarily to higher oil prices and higher oil production in Wolfcamp and Altamont. Partially offsetting this increase was a decrease in oil volumes in Eagle Ford reflecting the slowed pace of development of that program in 2016. For the quarter and six months ended June 30, 2017 compared to the same periods in 2016, Eagle Ford oil production decreased by 3% (0.9 MBbls/d) and 15% (4.6 MBbls/d), respectively.

Natural gas sales increased for the quarter and decreased for the six months ended June 30, 2017 compared to the same periods in 2016. For the quarter ended June 30, 2017 compared to the same period in 2016, the increase in natural gas prices and natural gas volume growth primarily in Wolfcamp more than offset the decrease in volumes from the sale of our Haynesville Shale assets in May 2016. However, for the six months ended June 30, 2017, the impact of lower volumes due to the sale of Haynesville was only partially offset by higher natural gas prices and higher natural gas volumes in Wolfcamp. For the quarter and six months ended June 30, 2016, the Haynesville Shale produced a total of 38 MMcf/d and 75 MMcf/d, respectively, of natural gas.

Our oil, natural gas and NGLs are sold at index prices (WTI, LLS, Henry Hub and Mt. Belvieu) or refiners' 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 deductions, differentials from the index to the delivery point, adjustments for time, and/or discounts for quality or grade.

In the Eagle Ford, our oil is sold at prices tied to benchmark LLS crude oil. In Wolfcamp, physical barrels are generally sold at the WTI Midland Index, which trades at a spread to WTI Cushing. In Altamont, market pricing of our oil is based upon 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 June 30,			
	2017		2016	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(3.16)	$ (0.79)	$(5.36)	$ (0.34)
NYMEX	$48.29	$ 3.19	$45.59	$ 1.95
Net back realization %	93.5 %	75.2 %	88.2 %	82.6 %

	Six months ended June 30,			
	2017		2016	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(3.52)	$ (0.80)	$(5.82)	$ (0.30)
NYMEX	$50.10	$ 3.25	$39.52	$ 2.02
Net back realization %	93.0 %	75.4 %	85.3 %	85.1 %

The higher oil realization percentage in the quarter and six months ended June 30, 2017 was primarily a result of improved physical sales contracts in all programs. The lower natural gas realization percentage in the quarter and six months ended June 30, 2017 was 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 in 2017 was the impact on basis differentials in Wolfcamp due to constrained natural gas takeaway capacity in the basin.

NGLs sales increased by $7 million and $19 million, respectively, for the quarter and six months ended June 30, 2017 compared with the same periods in 2016. Average realized prices for the quarter and six months ended June 30, 2017 were higher compared to the same periods in 2016, due to higher pricing on all liquids components. NGLs pricing is largely tied to crude oil prices. NGLs volumes increased approximately 9% and 4% for the quarter and six months ended June 30, 2017 compared to the same periods in 2016 due to NGLs volume growth in Wolfcamp.

Future growth in our overall oil and natural gas sales (including the impact of financial derivatives) will largely be impacted by commodity pricing, our level of hedging, our ability to maintain or grow oil volumes and by the location of our production and the nature of our sales contracts. See "Our Business" and "Liquidity and Capital Resources" for further information on our derivative instruments.

Gains or losses on financial derivatives. We record gains or losses due to changes in the fair value of our derivative contracts based on forward commodity prices relative to the prices in the underlying contracts. We realize such gains or losses when we settle the derivative position. During the quarter ended June 30, 2017, we recorded $45 million of derivative gains compared to derivative losses of $105 million during the quarter ended June 30, 2016. For the six months ended June 30, 2017, we recorded derivative gains of $115 million compared to derivative losses of $63 million during the six months ended June 30, 2016.

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Operating Expenses

The table below provides our operating expenses, volumes and operating expenses per unit for each of the periods presented:

	Quarter ended June 30,			
	2017		2016	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Operating expenses				
Oil and natural gas purchases	$ 1	$ 0.09	$ 3	$ 0.38
Transportation costs	28	3.66	24	3.19
Lease operating expense	39	5.07	38	4.93
General and administrative(2)	26	3.43	32	4.20
Depreciation, depletion and amortization	124	15.99	97	12.67
Gain on sale of assets	—	—	(82)	(10.77)
Impairment charges	1	0.05	—	—
Exploration and other expense	1	0.20	1	0.12
Taxes, other than income taxes	15	1.97	14	1.75
Total operating expenses	$ 235	$ 30.46	$ 127	$ 16.47
Total equivalent volumes (MBoe)	7,730		7,691	

	Six months ended June 30,			
	2017		2016	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Operating expenses				
Oil and natural gas purchases	$ 2	$ 0.12	$ 7	$ 0.42
Transportation costs	57	3.75	54	3.15
Lease operating expense	79	5.21	80	4.63
General and administrative(2)	46	3.05	70	4.11
Depreciation, depletion and amortization	250	16.48	210	12.27
Gain on sale of assets	—	—	(82)	(4.81)
Impairment charges	1	0.04	—	—
Exploration and other expense	4	0.29	2	0.11
Taxes, other than income taxes	34	2.28	28	1.64
Total operating expenses	$ 473	$ 31.22	$ 369	$ 21.52
Total equivalent volumes (MBoe)	15,156		17,157	

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

(2) For the quarter and six months ended June 30, 2017, amount includes approximately $6 million or $0.80 per Boe and $2 million or $0.14 per Boe, respectively, of non-cash compensation expense. For the quarter and six months ended June 30, 2016, amount includes approximately $2 million or $0.25 per Boe and $10 million or $0.57 per Boe, respectively, of transition and severance costs related to workforce reductions and $3 million or $0.35 per Boe and $7 million or $0.39 per Boe, respectively, of non-cash compensation expense.

Oil and natural gas purchases. From time to time, we purchase and sell oil and natural gas 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 six months ended June 30, 2017 decreased by $2 million and $5 million, respectively, compared to the same periods in 2016 primarily due to fewer transactions following the sale of our Haynesville assets in May 2016.

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Transportation costs. Transportation costs for the quarter and six months ended June 30, 2017 increased by $4 million and $3 million, respectively, compared to the same periods in 2016 due to an increase in gas transportation costs in Wolfcamp as a result of production growth in that area and certain legacy transportation commitments that commenced in August 2016.

Lease operating expense. Lease operating expense increased for the quarter and decreased for the six months ended June 30, 2017 compared to the same periods in 2016 by $1 million, respectively. The increase for the quarter ended June 30, 2017 compared to 2016 is due to higher maintenance and repair costs in Wolfcamp and Altamont, partially offset by lower disposal and chemical costs in Eagle Ford. For the six months ended June 30 2017 compared to 2016, these lower disposal and chemical costs in Eagle Ford and the sale of Haynesville in May 2016, were only partially offset by the higher maintenance and repair costs in our Wolfcamp and Altamont areas. On an equivalent per unit basis, lease operating expense for the quarter and six months ended June 30, 2017 compared to the same periods in 2016 increased by 3% and 13%, respectively, due to lower production volumes in 2017.

General and administrative expenses. General and administrative expenses for the quarter and six months ended June 30, 2017 decreased by $6 million and $24 million, respectively, compared to the same periods in 2016. Lower costs during the quarter and six months ended June 30, 2017 compared to the same periods in 2016 included lower payroll, benefits and administrative costs of $3 million and $15 million, respectively, and lower severance expense of $2 million and $9 million, respectively. The lower payroll, benefits and administrative costs resulted from lower headcount in 2017 when compared to the same periods in 2016.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense for the quarter and six months ended June 30, 2017 increased compared to the same periods in 2016 due primarily to a reduction in reserves in Eagle Ford and higher Wolfcamp and Altamont volumes during the quarter and six months ended June 30, 2017 compared to 2016. Our Wolfcamp and Altamont areas have a higher depreciation, depletion and amortization cost per unit than Eagle Ford as a result of a non-cash impairment charge recorded in 2015 on our proved properties in Eagle Ford. Our average depreciation, depletion and amortization costs per unit for the quarters ended June 30 were:

	Quarter ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Depreciation, depletion and amortization ($/Boe)	$15.99	$12.67	$16.48	$12.27

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. For the full year 2017, we currently anticipate our depreciation, depletion and amortization costs per unit to be between $16.00 and $17.00 per Boe.

Gain on sale of assets. For the quarter and six months ended June 30, 2016, we recorded an $83 million gain related to the sale of our assets in the Haynesville and Bossier shales completed in May 2016.

Taxes, other than income taxes. Taxes, other than income taxes, for the quarter and six months ended June 30, 2017 increased by $1 million and $6 million, respectively, from the same periods in 2016 due to an increase of severance taxes as a result of higher commodity prices.

Other Income Statement Items.

Gain (loss) on extinguishment of debt. During the quarter and six months ended June 30, 2017, we paid approximately $42 million in cash to repurchase approximately $56 million in aggregate principal amount of our senior unsecured notes due 2020. We recorded a gain on extinguishment of debt of approximately $13 million (including $1 million in non-cash expense related to eliminating associated unamortized debt issue costs). In addition, during the first quarter of 2017, we retired our senior secured term loans due 2021 and a portion of our 9.375% senior notes due 2020, recording a loss on extinguishment of debt of approximately $53 million (including $30 million in non-cash expense related to eliminating associated unamortized debt issue costs and debt discounts). Subsequent to June 30, 2017, we repurchased additional senior unsecured notes due 2020 and 2023 and will record additional gain on extinguishment of debt during the third quarter of 2017.

For the quarter and six months ended June 30, 2016, we paid approximately $217 million and $360 million, respectively, in cash to repurchase a total of approximately $392 million and $737 million, respectively, in aggregate principal amount of our senior unsecured notes and term loans. We recorded a gain on extinguishment of debt of approximately $170 million in the second quarter and $366 million year to date which included $5 million and $11 million, respectively, of non-cash expense related to eliminating associated unamortized debt issue costs. In addition, for the quarter and six months ended June 30, 2016, we recorded a loss on extinguishment of debt of approximately $8 million related to eliminating a portion of the unamortized debt issue costs on our Reserve-Based Loan facility (RBL Facility) due to the reduction of our borrowing base in May 2016.

Interest expense. Interest expense for the quarter and six months ended June 30, 2017 increased by $9 million and $8 million, respectively, compared to the same periods in 2016 due primarily to the issuance in late 2016 and 2017 of $1.5 billion in senior secured notes due in 2024 and 2025, primarily to repay or repurchase certain of our debt obligations and repay certain amounts outstanding under our RBL Facility, partially offset by lower interest expense related to borrowings under our RBL Facility.

Income taxes. For the quarter and six months ended June 30, 2017, our effective tax rates were approximately 59% and 8%, respectively. For both the quarter and six months ended June 30, 2016 our effective tax rates were 0%. Our effective tax rates in 2017 and 2016 differed from the statutory rate primarily as a result of our recognition of a full valuation allowance on our deferred tax assets. For the quarters ended June 30, 2017 and 2016 we recorded adjustments to the valuation allowance on our deferred tax assets which offset deferred income tax expense of $3 million and $24 million, respectively, and offset deferred income tax benefit and deferred income tax expense of $12 million and $59 million for the six months ended June 30, 2017 and 2016, respectively. Our effective tax rate for both the quarter and six months ended June 30, 2017 also reflects recording an income tax benefit for the recovery of previously paid alternative minimum taxes based on our 2016 depreciation elections.

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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 these plans), transition, severance and other costs that affect comparability, gains and losses on sale of assets, gains and losses on extinguishment of debt and impairment charges.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business 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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
	(in millions)			
Net (loss) income	$(3)	$62	$(50)	$156
Income tax benefit	(5)	—	(5)	—
Interest expense, net of capitalized interest	82	73	165	157
Depreciation, depletion and amortization	124	97	250	210
Exploration expense	1	1	4	2
EBITDAX	199	233	364	525
Mark-to-market on financial derivatives(1)	(45)	105	(115)	63
Cash settlements and cash premiums on financial derivatives(2)	31	157	59	369
Non-cash portion of compensation expense(3)	6	3	2	7
Transition, severance and other costs(4)	—	2	—	10
Gain on sale of assets(5)	—	(82)	—	(82)
(Gain) loss on extinguishment of debt	(13)	(162)	40	(358)
Impairment charges	1	—	1	—
Adjusted EBITDAX	$179	$256	$351	$534

(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 six months ended June 30, 2017 and 2016.

(3) For the six months ended June 30, 2017, the non-cash portion of compensation expense includes cash payments of approximately $4 million. For both the quarter and six months ended June 30, 2016, cash payments were approximately $3 million.
(4) Reflects transition and severance costs related to workforce reductions.
(5) Represents the gain on the sale of our Haynesville Shale assets sold in May 2016.

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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 $1,062 million as of June 30, 2017.

In 2017, we continued to take steps to improve our liquidity, strengthen our balance sheet and expand our financial flexibility. These steps have included (i) issuing $1 billion of 8.00% senior secured notes which mature in 2025 and using the net proceeds to repay in full our $580 million senior secured term loans due 2021, repurchase $250 million of our 9.375% senior notes due 2020, and repay $111 million of the amounts outstanding under our RBL Facility and (ii) repurchasing for cash a total of $157 million in aggregate principal amount ($56 million repurchased as of June 30, 2017) of our senior unsecured notes due 2020 and 2023 for approximately $118 million ($42 million as of June 30, 2017).

Our RBL Facility has a borrowing base subject to semi-annual redetermination. In February 2017, as a result of the issuance of our $1 billion senior secured notes due 2025, our RBL borrowing base was reduced to $1.44 billion. In April 2017, we completed the semi-annual redetermination and reaffirmed the borrowing base at $1.44 billion. 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.

In April 2017, in conjunction with the redetermination, our first lien debt to EBITDAX covenant was extended through March 31, 2019. In addition, the first lien debt to EBITDAX ratio covenant was reduced to 3.0 to 1.0, and the company paid an amendment fee of approximately $1 million. As of June 30, 2017 our ratio of first lien debt to EBITDAX was 0.47x. In April 2019, this financial covenant will revert to a requirement that our total debt to EBITDAX ratio not exceed 4.5 to 1.0, and in May 2019 our RBL Facility will mature. Under our RBL Facility, we are also limited in non-RBL Facility debt repurchases to $350 million, subject to certain adjustments. As of July 31, 2017, the non-RBL Facility debt repurchases limit was approximately $900 million as a result of recent divestitures and financing transactions and will continue to be subject to future adjustments.

For 2017 and 2018, we have derivative contracts on 5.0 MMBbls and 8.9 MMBbls of our anticipated oil production at a weighted average price of $60.34 and $60.00 per barrel of oil, respectively. For 2017, 2018 and 2019, we have derivative contracts on 17 TBtu, 26 TBtu and 7 TBtu of our anticipated natural gas production at a weighted average price of $3.28, $3.04 and $2.97 per MMBtu, respectively. As of June 30, 2017 based on the mid-point of our forecasted 2017 guidance, our oil and natural gas derivative contracts provide price protection on approximately 63% and 69%, respectively, of our anticipated 2017 oil and natural gas production and approximately 52% and 55% on our 2018 oil and natural gas production, respectively. See "Our Business" for further information on our derivative instruments.

For 2017, we expect to spend approximately $550 million to $600 million in capital in our programs. Based upon our current price and cost assumptions, including the impact of our hedges, we believe that our current capital program will exceed our estimated operating cash flows. We believe the borrowing capacity under our RBL Facility together with expected cash flows from our 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 ongoing volatility in the energy industry and in 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 drilling programs, (ii) meeting our debt maturities, and (iii) managing and working to strengthen our balance sheet. 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. Accordingly, we will continue to pursue cost saving measures where possible to reduce our capital, operating, and general and administrative costs, which may include renegotiating contracts with contractors, suppliers and service providers, deferring and eliminating various discretionary costs, and/or reducing the number of staff and contractors, if necessary.

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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 them or that affect our 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 make changes 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 limitations in our RBL Facility 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 that 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 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 spending program.

Capital Expenditures. Our capital expenditures and average drilling rigs by area for the six months ended June 30, 2017 were:

	Capital Expenditures(1) (in millions)	Average Drilling Rigs
Eagle Ford Shale	$ 122	1.0
Wolfcamp Shale	113	2.0
Altamont	45	1.6
Total	$ 280	4.6

(1) Represents accrual-based capital expenditures.

Debt. As of June 30, 2017, our total debt was approximately $4.0 billion, comprised of $29 million in senior secured term loans with maturity dates in 2018 and 2019, $400 million outstanding under the RBL Facility which matures in 2019, $2.1 billion in senior unsecured notes due in 2020, 2022 and 2023, and $1.5 billion in senior secured notes due in 2024 and 2025. 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 are summarized as follows (in millions):

	Six months ended June 30,	
	2017	2016
Cash Inflows		
Operating activities		
Net (loss) income	$(50)	$156
Gain on sale of assets	—	(82)
Loss (gain) on extinguishment of debt	40	(358)
Other income adjustments	265	227
Changes in assets and liabilities	(74)	463
Total cash flow from operations	$181	$406
Investing activities		
Proceeds from the sale of assets	—	390
Cash inflows from investing activities	$—	$390
Financing activities		
Proceeds from issuance of long-term debt	1,385	575
Cash inflows from financing activities	$1,385	$575
Total cash inflows	$1,566	$1,371
Cash Outflows		
Investing activities		
Capital expenditures	$266	$258
Financing activities		
Repayments and repurchases of long-term debt	$1,253	$1,097
Debt issue costs	20	1
Other	3	2
	$1,276	$1,100
Total cash outflows	$1,542	$1,358
Net change in cash and cash equivalents	$24	$13

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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 consolidated balance sheet. The following table and discussion summarizes our contractual cash obligations as of June 30, 2017, for each of the periods presented:

	2017	2018- 2019	2020 - 2021	Thereafter	Total
			(in millions)		
Financing obligations:					
Principal	$—	$ 429	$ 1,269	$ 2,301	$3,999
Interest	156	613	388	431	1,588
Operating leases	4	10	10	22	46
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	33	126	109	47	315
Other obligations	16	40	—	—	56
Total contractual obligations	$209	$ 1,218	$ 1,776	$ 2,801	$6,004

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. Subsequent to June 30, 2017, we repurchased $101 million of our senior unsecured notes due 2020 and 2023.

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. Amounts in the schedule above approximate the 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, completion 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 and 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 2016 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 2016 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at June 30, 2017:

	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)	$114	$64	$ (50)	$ 155	$ 41

	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)	$114	$113	$ (1)	$ 115	$ 1
Credit rate(3)	$114	$112	$ (2)	$ 114	$ —

(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 June 30, 2017, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our interim Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Securities Exchange Act of 1934, as amended (Exchange Act), is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of June 30, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in EP Energy Corporation’s internal control over financial reporting during the first six months of 2017 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 2016 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: August 3, 2017 /s/ Kyle A. McCuen
Kyle A. McCuen
Vice President, Interim Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: August 3, 2017 /s/ Francis C. Olmsted III
Francis C. Olmsted III
Vice President and Chief Accounting Officer
(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	Sixth Amendment, dated as of November 11, 2016, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent.
*10.2	Seventh Amendment, dated as of April 24, 2017, to the Credit Agreement, dated as of May 24, 2012, among EPE Acquisition, LLC, EP Energy LLC, the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent and collateral agent.
*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.