EP Energy Corp
Form 10-Q
May 09, 2018
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2018
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 April 30, 2018: 251,100,549

Class B Common Stock, par value $0.01 per share. Shares outstanding as of April 30, 2018: 265,329

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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", "plan", "intend", "co "should", "project" 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 2017 Annual Report on Form 10-K. There have been no material changes to the risk factors described in the Form 10-K.

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PART I — FINANCIAL INFORMATION

Item 1. Financial Statements

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

	Quarter ended March 31, 2018	Quarter ended March 31, 2017
Operating revenues		
Oil	$252	$204
Natural gas	22	30
NGLs	26	23
Financial derivatives	(14)	70
Total operating revenues	286	327
Operating expenses		
Oil and natural gas purchases	—	1
Transportation costs	25	29
Lease operating expense	39	40
General and administrative	19	20
Depreciation, depletion and amortization	120	126
Exploration and other expense	1	3
Taxes, other than income taxes	20	19
Total operating expenses	224	238
Operating income	62	89
Gain (loss) on extinguishment/modification of debt	41	(53)
Interest expense	(85)	(83)
Income (loss) before income taxes	18	(47)
Income tax expense	—	—
Net income (loss)	$18	$(47)
Basic and diluted net income (loss) per common share		
Net income (loss)	$0.07	$(0.19)
Basic and diluted weighted average common shares outstanding	247	245

See accompanying notes.

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

	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$19	$ 27
Restricted cash	1	18
Accounts receivable		
Customer, net of allowance of less than $1 in 2018 and 2017	166	158
Other, net of allowance of $1 in 2018 and 2017	10	13
Income tax receivable	5	9
Materials and supplies	20	16
Derivative instruments	11	18
Assets held for sale	—	172
Prepaid assets	5	35
Total current assets	237	466
Property, plant and equipment, at cost		
Oil and natural gas properties	7,978	7,532
Other property, plant and equipment	70	69
	8,048	7,601
Less accumulated depreciation, depletion and amortization	3,307	3,179
Total property, plant and equipment, net	4,741	4,422
Other assets		
Derivative instruments	5	4
Unamortized debt issue costs - revolving credit facility	5	6
Other	1	2
	11	12
Total assets	$4,989	$ 4,900

See accompanying notes.

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

	March 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities		
Accounts payable		
Trade	$90	$ 88
Other	170	158
Derivative instruments	15	17
Accrued interest	68	62
Liabilities related to assets held for sale	—	2
Short-term debt, net of debt issue costs	21	21
Other accrued liabilities	72	100
Total current liabilities	436	448
Long-term debt, net of debt issue costs	4,104	4,022
Other long-term liabilities		
Asset retirement obligations	34	33
Other	5	5
Total non-current liabilities	4,143	4,060
Commitments and contingencies (Note 8)		
Stockholders' equity		
Class A shares, $0.01 par value; 550 million shares authorized; 251 million shares issued and outstanding at March 31, 2018; 252 million shares issued and outstanding at December 31, 2017	3	3
Class B shares, $0.01 par value; 0.3 million shares authorized, issued and outstanding at March 31, 2018 and December 31, 2017	—	—
Preferred stock, $0.01 par value; 50 million shares authorized; no shares issued or outstanding	—	—
Treasury stock (at cost), one million shares at March 31, 2018 and 0.7 million shares at December 31, 2017	(4)	(3)
Additional paid-in capital	3,527	3,526
Accumulated deficit	(3,116)	(3,134)
Total stockholders' equity	410	392
Total liabilities and equity	$4,989	$ 4,900

See accompanying notes.

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

	Three months ended March 31, 2018	2017
Cash flows from operating activities		
Net income (loss)	$18	$(47)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depreciation, depletion and amortization	120	126
(Gain) loss on extinguishment/modification of debt	(41)	53
Other non-cash income items	5	5
Asset and liability changes		
Accounts receivable	(6)	(9)
Accounts payable	(15)	2
Derivative instruments	4	(43)
Accrued interest	6	48
Other asset changes	7	1
Other liability changes	(11)	(19)
Net cash provided by operating activities	87	117
Cash flows from investing activities		
Cash paid for capital expenditures	(173)	(119)
Proceeds from the sale of assets	167	—
Cash paid for acquisitions	(223)	—
Net cash used in investing activities	(229)	(119)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	460	1,125
Repayments and repurchases of long-term debt	(280)	(1,086)
Fees/costs on debt exchange	(62)	—
Debt issue costs	—	(19)
Other	(1)	(3)
Net cash provided by financing activities	117	17
Change in cash, cash equivalents and restricted cash	(25)	15
Cash, cash equivalents and restricted cash - beginning of period	45	20
Cash, cash equivalents and restricted cash - end of period	$20	$35

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 Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total
	Shares	Amount	Shares	Amount				
Balance at December 31, 2017	252	$ 3	0.3	$ —	$ (3)	$ 3,526	$ (3,134)	$ 392
Share-based compensation	(1)	—	—	—	(1)	1	—	—
Net income	—	—	—	—	—	—	18	18
Balance at March 31, 2018	251	$ 3	0.3	$ —	$ (4)	$ 3,527	$ (3,116)	$ 410

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 2017 Annual Report on
Form 10-K. The condensed consolidated financial statements as of March 31, 2018 and 2017 are unaudited. The consolidated balance sheet as of December 31, 2017 has been derived from the audited consolidated balance sheet included in our 2017 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

In the first quarter of 2018, we adopted Accounting Standards Update (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. As permitted under ASU No. 2014-09, we elected to utilize the modified retrospective approach, which did not have a material impact on our financial statements. There were no other changes in significant accounting policies as described in the 2017 Annual Report on Form 10-K.

New Accounting Pronouncements Issued But Not Yet Adopted

The following accounting standards have been issued but not yet adopted as of March 31, 2018.

Leases. In February 2016, the Financial Accounting Standards Board (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.

2. Acquisitions and Divestitures

Acquisitions. In January 2018, we completed the acquisition of producing properties and undeveloped acreage in Eagle Ford for approximately $246 million, after customary adjustments. Of the total purchase price, we paid $221 million upon closing during the first quarter of 2018 and $25 million to the buyer as a deposit in December 2017. Our consolidated balance sheet reflects our preliminary allocation of the purchase price to the underlying acquired proved properties. No goodwill or bargain purchase was recorded on the acquisition.

Divestitures. In February 2018, we completed the sale of certain assets in the Altamont area for approximately $177 million, after customary adjustments. Of the total sales price, we received a deposit of $18 million in December 2017 (reflected in restricted cash in the balance sheet) and additional cash proceeds of $159 million upon closing. We treated this sale as a normal retirement reflecting the difference between net cash proceeds and the underlying net book value of the assets sold in accumulated depreciation rather than recording a gain on sale of assets. As of December 31, 2017, we classified the assets and liabilities associated with the assets to be sold as held for sale in our consolidated balance sheet.

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.

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For both of the quarters ended March 31, 2018 and 2017, our effective tax rates were approximately 0%. Our effective tax rates in 2018 and 2017 differed from the statutory rates of 21% and 35%, respectively, primarily as a result of our recognition of a full valuation allowance on our net deferred tax assets. For the quarters ended March 31, 2018 and 2017, we recorded adjustments to the valuation allowance on our net deferred tax assets, which offset deferred income tax expense by $5 million and deferred income tax benefit by $15 million, respectively.

During 2017, we recorded a provisional effect of the Tax Cuts and Jobs Act (the Act). While there was no overall impact on our financial statements from the Act, we are still analyzing certain aspects of the Act with available guidance and have no adjustments to the recorded provisional amounts.

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 $639 million as of March 31, 2018.

For the quarter ended March 31, 2018, we received federal and state refunds of $5 million. The Company's and certain subsidiaries' income tax years after 2013 remain open and subject to examination by both federal and state tax authorities.

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 our stock options, restricted stock, performance share unit awards and performance unit awards. For the quarter ended March 31, 2018, less than one million shares are included as dilutive securities in our calculation of diluted earnings per share. For the quarter ended March 31, 2017, we incurred net losses and accordingly excluded all potentially dilutive securities from the determination of diluted earnings per share as their impact on loss per common share was antidilutive.

5. Fair Value Measurements

We use various methods to determine the fair values of our financial instruments. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into three levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of March 31, 2018 and December 31, 2017, 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:

	March 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Short-term debt	$21	$20	$21	$19
Long-term debt (see Note 7)	$4,197	$3,226	$4,072	$3,248
Derivative instruments	$1	$1	$5	$5

As of March 31, 2018 and December 31, 2017, 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 March 31, 2018, we had derivative contracts in the form of fixed price swaps and three-way collars on 14 MMBbls of oil (11 MMBbls in 2018 and 3 MMBbls in 2019). In addition to our oil derivatives, we had derivative contracts in the form of fixed

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price swaps and options on 26 TBtu of natural gas (19 TBtu in 2018 and 7 TBtu in 2019) and 69 MMGal of ethane and propane fixed price swaps in 2018. As of December 31, 2017, we had derivative contracts for 14 MMBbls of oil, 33 TBtu of natural gas and 92 MMGal of ethane and propane. 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 March 31, 2018 and December 31, 2017. 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.

	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)			
March 31, 2018								
Derivative instruments	$33	$ (17)	$ 11	$ 5	$(32)	$ 17	$ (15)	$ —
December 31, 2017								
Derivative instruments	$33	$ (11)	$ 18	$ 4	$(28)	$ 11	$ (17)	$ —

For the quarters ended March 31, 2018 and 2017, we recorded a derivative loss of $14 million and a derivative gain of $70 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 March 31, 2018 and December 31, 2017, we had approximately $4.7 billion and $4.4 billion, respectively, 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:

	March 31, 2018	December 31, 2017
	(in millions)	
Proved		
Eagle Ford	$3,597	$ 3,219
Permian	2,747	2,705
Altamont	1,569	1,542
Total Proved	7,913	7,466
Unproved		
Permian	65	66
	(3,263)	(3,137)

Less accumulated depletion		
Net capitalized costs for oil and natural gas properties	$ 4,715	$ 4,395

For the quarters ended March 31, 2018 and 2017, we recorded less than $1 million and $1 million, respectively, of amortization of unproved leasehold costs in exploration expense in our consolidated income statements. Suspended well costs were not material as of March 31, 2018 or December 31, 2017.

We evaluate capitalized costs related to proved properties upon a triggering event (such as a significant continued 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

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relative to forward commodity prices and/or potential lease expirations. Commodity price declines may cause changes to our capital spending levels, production rates, levels of proved reserves and development plans, which may result in an impairment of the carrying value of our proved and/or unproved properties in the future.

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 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 percent and 9 percent on a significant portion of our obligations and a projected inflation rate of 2.5 percent. Changes in estimates in the table below 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 March 31, 2018 on our consolidated balance sheet in other current and non-current liabilities and the changes in the net liability from January 1 through March 31, 2018 were as follows:

	2018 (in millions)
Net asset retirement liability at January 1	$ 35
Accretion expense	1
Net asset retirement liability at March 31	$ 36

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 using a weighted average interest rate on our outstanding borrowings. Capitalized interest for both of the quarters ended March 31, 2018 and 2017 was approximately $1 million.

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7. Long-Term Debt

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

	Interest Rate	March 31, 2018	December 31, 2017
		(in millions)	
RBL credit facility - due May 24, 2019[(1)]	Variable	$775	$ 595
Senior secured term loans:			
Due May 24, 2018[(2)(3)]	Variable	21	21
Due April 30, 2019[(4)]	Variable	8	8
Senior secured notes:			
Due May 1, 2024	9.375%	1,092	—
Due November 29, 2024	8.00%	500	500
Due February 15, 2025	8.00%	1,000	1,000
Senior unsecured notes:			
Due May 1, 2020	9.375%	246	1,200
Due September 1, 2022	7.75%	196	250
Due June 15, 2023	6.375%	380	519
Total debt		4,218	4,093
Less short-term debt, net of debt issue costs of less than $1 million		(21)	(21)
Total long-term debt		4,197	4,072
Less debt discount and non-current portion of unamortized debt issue costs		(93)	(50)
Total long-term debt, net		$4,104	$ 4,022

(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 LIBOR of 2.75%, with a minimum LIBOR floor of 0.75%. As of March 31, 2018 and December 31, 2017, the effective interest rate of the term loan was 4.54% and 4.23%, respectively.

(3) In April 2018, we retired the note in full.

(4) Carries interest at a specified margin over the LIBOR of 3.50%, with a minimum LIBOR floor of 1.00%. As of March 31, 2018 and December 31, 2017, the effective interest rate for the term loan was 5.48% and 4.98%, respectively.

During the first quarter of 2018, we completed an exchange of $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes maturing in May 2020, September 2022 and June 2023, respectively, for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million. The exchange transaction was accounted for as a modification of debt for our senior unsecured notes maturing in May 2020 and an extinguishment of debt for our senior unsecured notes maturing in September 2022 and June 2023. In conjunction with the exchange, we incurred approximately $62 million in related fees, of which we (i) recorded $48 million as debt discount primarily reflecting amounts paid to our 2020 noteholders associated with the exchange of our 2020 notes, (ii) capitalized $2 million as debt issuance costs, and (iii) recorded $12 million in loss on modification of debt. In addition, we recorded a gain on extinguishment of debt in the amount of $53 million primarily associated with retiring a portion of our 2022 and 2023 notes at less than face value, net of the write-off of $2 million in previously unamortized debt issue costs.

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 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). 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).

Unamortized Debt Issue Costs and Debt Discounts. As of March 31, 2018, we had total debt discount of $47 million associated with our senior secured notes maturing in 2024 and as of December 31, 2017, we had less than $1 million. As of March 31, 2018 and December 31, 2017, we had total unamortized debt issue costs of $51 million and $56 million, respectively. Of these amounts, $5 million and $6 million, respectively, are associated with our RBL Facility and $46 million and $50 million, respectively, are associated with our senior secured term loans and senior notes. Debt discounts and unamortized debt issue costs are reflected net of the face value of debt on our consolidated balance sheet.

Reserve-based Loan Facility. We have a $1.36 billion RBL Facility in place which allows us to borrow funds or issue letters of credit (LC's). The facility matures in May 2019. As of March 31, 2018, we had $565 million of capacity remaining with approximately $19 million of LC's issued and approximately $775 million outstanding under the RBL 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 January 2018, as a result of the debt exchange, our borrowing base was reduced from $1.4 billion to $1.36 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.

Restrictive Provisions/Covenants. The availability of borrowings under our RBL Facility and our ability to incur additional indebtedness is subject to various financial and non-financial covenants and restrictions. Our current financial covenants require us to maintain a ratio of first lien debt to EBITDAX not exceeding 3.0 to 1.0. As of March 31, 2018, we were in compliance with our debt covenants, and our ratio of first lien debt to EBITDAX was 1.09x.

In the second quarter of 2019, our RBL Facility matures and our financial covenant will revert to a 4.5 to 1.0 debt to EBITDAX requirement absent a renegotiation of its terms and covenants. As of March 31, 2018, our ratio of total net debt to EBITDAX was 5.93x. Based on our current outlook, including forecasted EBITDAX and expected borrowings to fund capital expenditures, we anticipate this ratio will continue to exceed the 4.5 to 1.0 total net debt to EBITDAX ratio for the remainder of 2018 through the second quarter of 2019. We are currently working to renew and extend the RBL Facility and renegotiate the required covenants thereunder. Based on actions and negotiations to date, we believe that we will be successful in extending the RBL Facility and renegotiating its various covenants. Should we not be successful, however, we believe we have other ways to mitigate the condition, including the issuance of new debt, equity, or selling assets.

Under our various debt agreements, we are limited in our ability to repurchase certain tranches of non-RBL Facility debt. Under our new 2024 senior secured notes issued January 2018, we are limited in our ability to repurchase certain tranches of unsecured notes and under our RBL Facility, we are limited in our ability to repurchase certain tranches of secured and unsecured debt. Certain other covenants and restrictions, among other things, also limit or place certain conditions on our ability to incur or guarantee additional indebtedness, make restricted payments, pay dividends on equity interests, redeem, repurchase or retire equity interests or subordinated indebtedness, sell assets, make investments, create certain liens, prepay debt obligations, engage in certain transactions with affiliates, and enter into certain hedging 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 March 31, 2018, we had approximately $5 million accrued for all outstanding legal matters.

FairfieldNodal v. EP Energy E&P Company, L.P. On March 3, 2014, Fairfield filed suit against one of our subsidiaries in the 157th District Court of Harris County, Texas, 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 and denied rehearing on October 5, 2017. We filed a petition for review in the Texas Supreme Court in December 2017. At this time, we are unable to estimate the amount or range of possible loss, if any, on this matter.

Weyerhaeuser Company v. Pardee Minerals LLC, et al. On July 5, 2017, Weyerhaeuser filed suit against one of our subsidiaries, among other defendants, in the United States District Court for the Western District of Louisiana. Weyerhaeuser

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seeks to recoup the value of production (approximately $19 million) plus judicial interest (approximately $11 million at this time) from certain wells drilled by EP Energy between 2002 and 2013 on leases Weyerhaeuser claims were invalid. Weyerhaeuser alleges that lessees prior to EP Energy had not drilled wells in good faith to perpetuate the associated mineral servitude (rights conveyed to produce minerals), rendering EP Energy's subsequent lease invalid. A trial date has been set for December 10, 2018. 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 March 31, 2018, we had approximately $4 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 March 31, 2018, we had approximately $43 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 2017 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 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

Our long-term incentive (LTI) programs consist of restricted stock, stock options and performance shares/units awards. Refer to our 2017 Annual Report on Form 10-K for further description regarding the terms and details of these awards.

Restricted Stock. A summary of the changes in our non-vested restricted shares for the quarter ended March 31, 2018 is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value per Share
Non-vested at December 31, 2017	5,283,986	$ 4.93
Granted	327,796	$ 1.80

Vested	(1,695,087	)	$	5.90
Forfeited	(496,360	)	$	4.96
Non-vested at March 31, 2018	3,420,335		$	4.15

Performance Share Units. In 2017, we granted 912,000 performance share units (PSUs) to certain members of EP Energy’s management team. PSUs will be earned based upon achievement of specified stock price goals over a four-year performance period. Our PSUs are treated as an equity award with the expense recognized on an accelerated basis over the life of the award.

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Performance Unit Awards. Our performance unit awards are based upon achievement of a level of total shareholder return and may be settled in either stock or cash at the election of the Board of Directors. These awards are treated as a liability award for accounting purposes with the expense recognized on an accelerated basis over the life of the award and fair value remeasured at each reporting period. During the quarter ended March 31, 2018, we made no payment in connection with awards that vested and had less than $1 million accrued related to unvested outstanding performance unit awards. Had all outstanding performance unit awards at March 31, 2018 vested and been settled in stock, no shares would have been issued.

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 $2 million and $(1) million, respectively, for the quarters ended March 31, 2018 and 2017. Included in pre-tax compensation expense for the quarter ended March 31, 2017 was approximately $7 million of forfeitures. As of March 31, 2018, we had unrecognized compensation expense of $25 million. We will recognize an additional $10 million related to our outstanding awards during the remainder of 2018, $13 million over the remaining requisite service periods subsequent to 2018 and $2 million should a specified capital transaction occur and the right to such amounts become non-forfeitable.

10. Related Party Transactions

Joint Venture. In 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 the Permian basin. 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 agreed to fund 60 percent of the estimated drilling, completion and equipping costs in the joint venture wells, divided into two approximately $225 million investment tranches, in exchange for a 50 percent working interest. 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. Since January 2017, we have recovered approximately $215 million in capital costs from the Investor related to the first tranche, which we expect to complete in the second half of 2018. In April 2018, we amended the drilling joint venture to direct the second tranche investment to the Eagle Ford. The first wells in the second tranche are expected to begin producing later in 2018. We are the operator of the joint venture assets.

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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 2017 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 acquisition and development 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 providing returns to our shareholders through the development of our drilling inventory located in three areas: the Eagle Ford Shale in South Texas, the Permian basin in West Texas, and the Altamont Field in the Uinta basin in Northeastern Utah.

Our strategy is to invest in opportunities that provide the highest return across our asset base, continually seek out operating and capital efficiencies, effectively manage costs, and identify accretive acquisition opportunities and divestitures, all with the objective of enhancing our portfolio, growing asset value, improving cash flow, increasing financial flexibility and providing an attractive return to our shareholders. We evaluate opportunities in our portfolio that are aligned with this strategy and our core competencies and that offer a competitive advantage. In addition to opportunities in our current portfolio, strategic acquisitions of leasehold acreage or acquisitions of producing assets allow us to leverage existing expertise in our areas, balance our exposure to regions, basins and commodities, help us to achieve or enhance risk-adjusted returns competitive with those available in our existing programs and increase our reserves. We also continuously evaluate our asset portfolio and will sell oil and natural gas properties if they no longer meet our long-term objectives.

During the first quarter of 2018, we completed the acquisition of producing properties and undeveloped acreage in Eagle Ford, primarily in La Salle County, for approximately $246 million, after customary closing adjustments. The acquisition represents a 26 percent expansion of our Eagle Ford acreage position at December 31, 2017 or approximately 24,500 net acres. We also completed the sale of certain assets in the Altamont area for approximately $177 million, after customary closing adjustments. The divestiture represents approximately 13 percent of our Altamont acreage position at December 31, 2017, or approximately 23,330 net acres.
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 changes may affect our future capital spending levels, production rates and/or related operating revenues (net of any associated royalties), 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. While prices have generally improved over the past two years, future price declines, along with changes to our future capital spending levels, 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.

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Derivative Instruments. Our realized prices from the sale of our oil, natural gas and NGLs are affected by (i) commodity price movements, including locational or basis price differences that exist between the commodity index price (e.g., WTI) and the actual price at which we sell our commodities 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 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 quarter ended March 31, 2018, we (i) settled commodity index hedges on approximately 88% of our oil production, 78% of our total liquids production and on 56% of our natural gas production at average floor prices of $58.52 per barrel of oil, $0.45 per gallon of NGLs and $3.04 per MMBtu of natural gas, respectively. To the extent our oil, natural gas and NGLs 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 reflects the contracted volumes and the prices we will receive under derivative contracts we held as of March 31, 2018.

	2018		2019	
	Volumes[1]	Average Price[1]	Volumes[1]	Average Price[1]
Oil				
Fixed Price Swaps				
WTI	3,850	$56.49	730	$55.88
Collars				
Ceiling - WTI	825	$64.98	—	$—
Floors - WTI	825	$55.00	—	$—
Three Way Collars				
Ceiling - WTI	6,674	$68.15	1,825	$65.71
Floors - WTI	6,674	$60.00	1,825	$55.00
Sub-Floor - WTI	6,674	$50.00	1,825	$45.00
Basis Swaps				
LLS vs. WTI[2]	3,850	$2.84	—	$—
Midland vs. Cushing[3]	2,994	$(1.02)	—	$—
NYMEX Roll[4]	2,750	$0.09	—	$—
Natural Gas				
Fixed Price Swaps	19	$3.04	7	$2.97
Basis Swaps				
WAHA vs. Henry Hub[5]	11	$(0.46)	7	$(0.39)
NGLs				
Fixed Price Swaps - Ethane	46	$0.30	—	$—
Fixed Price Swaps - Propane	23	$0.75	—	$—

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

(3) EP Energy receives Cushing plus the basis spread listed and pays Midland. These positions do not include Midland vs. Cushing basis swaps, which offset our 3.30 MBbls Midland vs. Cushing with an average of $1.06 per barrel of oil and 306 MBbls of oil.

(4) These positions hedge the timing risk associated with our physical sales. We generally sell oil for the delivery month at a sales price based on the average NYMEX WTI

price during that month, plus an adjustment calculated as a spread between the weighted average prices of the delivery month, the next month and the following month
during the period when the delivery month is prompt (the "trade month roll").
(5) EP Energy receives Henry Hub plus the basis spread listed and pays WAHA.

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For the period from April 1, 2018 through May 7, 2018, we entered into the following additional derivative contracts.

	2019	
	Volumes[(1)]	Average Price[(1)]
Oil		
Collars		
Ceiling - WTI	1,275	$ 65.80
Floors - WTI	1,275	$ 55.00
Three Way Collars		
Ceiling - WTI	730	$ 67.53
Floors - WTI	730	$ 57.50
Sub-Floor - WTI	730	$ 45.00

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

For our three-way collar contracts in the tables above, the sub-floor prices represent the price below which we receive WTI plus a weighted average spread of $10.00 in 2018 and $10.71 in 2019 on the indicated volumes. If WTI is above our sub-floor prices, we receive the noted floor price until WTI exceeds that floor price. Above the floor price, we receive WTI until prices exceed the noted ceiling price in our three way collars, at which time we receive the fixed ceiling price. As of March 31, 2018, the average forward price of oil was $63.24 per barrel of oil for the remainder of 2018 and $58.73 per barrel of oil for 2019.

Summary of Liquidity and Capital Resources. As of March 31, 2018, we had available liquidity of approximately $584 million, reflecting $565 million of available liquidity on our Reserve-Based Loan facility (RBL Facility) borrowing base and $19 million of available cash. Our RBL Facility is our primary source of liquidity beyond our operating cash flow and matures in May of 2019.

In the first quarter of 2018, we took a number of steps to improve our liquidity, expand our financial flexibility and manage our leverage by exchanging approximately $1,147 million of the outstanding amounts of our senior unsecured notes maturing in 2020, 2022 and 2023 for new 9.375% senior secured notes maturing in 2024.

During the first quarter of 2018, we also (i) completed our largest acquisition to date in the Eagle Ford for approximately $246 million, after customary adjustments, while at the same time (ii) completed the sale of certain assets in Altamont for approximately $177 million after customary adjustments. 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 2018, we expect to spend approximately $600 million to $650 million in capital in our programs, with approximately 50% allocated to the Eagle Ford Shale, approximately 30% allocated to the Permian basin and approximately 20% allocated to Altamont. We anticipate our average daily production volumes for the year to be approximately 81 MBoe/d to 87 MBoe/d, including average daily oil production volumes of approximately 46 MBbls/d to 50 MBbls/d.

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Production Volumes and Drilling Summary

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

	2018	2017
Equivalent Volumes (MBoe/d)		
Eagle Ford Shale	35.9	37.7
Permian	27.0	27.5
Altamont	17.2	17.3
Total	80.1	82.5
Oil (MBbls/d)	45.4	46.9
Natural Gas (MMcf/d)	126	127
NGLs (MBbls/d)	13.7	14.4

- Eagle Ford Shale—Our Eagle Ford Shale equivalent volumes decreased 1.8 MBoe/d (approximately 5%) and oil production increased by 0.1 MBbls/d for the quarter ended March 31, 2018 compared to the same period in 2017. During the quarter ended March 31, 2018, we completed 19 additional operated wells in the Eagle Ford, for a total of 758 net operated wells as of March 31, 2018.

- Permian—Our Permian basin equivalent volumes decreased 0.5 MBoe/d (approximately 2%) and oil production decreased by 1.3 MBbls/d (approximately 12%) for the quarter ended March 31, 2018 compared to the same period in 2017. During the quarter ended March 31, 2018, we completed five additional operated wells for a total of 336 net operated wells as of March 31, 2018.

- Altamont—Our Altamont equivalent volumes decreased 0.1 MBoe/d (approximately 1%) and oil production decreased by 0.3 MBbls/d (approximately 3%) for the quarter ended March 31, 2018 compared to the same period in 2017. During the quarter ended March 31, 2018, we completed nine additional operated oil wells, for a total of 332 net operated wells as of March 31, 2018. We also recompleted 23 wells across our Altamont acreage.

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 area.

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Results of Operations

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

	Quarter ended March 31,	
	2018	2017
	(in millions)	
Operating revenues		
Oil	$252	$204
Natural gas	22	30
NGLs	26	23
Total physical sales	300	257
Financial derivatives	(14)	70
Total operating revenues	286	327
Operating expenses		
Oil and natural gas purchases	—	1
Transportation costs	25	29
Lease operating expense	39	40
General and administrative	19	20
Depreciation, depletion and amortization	120	126
Exploration and other expense	1	3
Taxes, other than income taxes	20	19
Total operating expenses	224	238
Operating income	62	89
Gain (loss) on extinguishment/modification of debt	41	(53)
Interest expense	(85)	(83)
Income (loss) before income taxes	18	(47)
Income tax expense	—	—
Net income (loss)	$18	$(47)

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Operating Revenues

The table below provides our operating revenues, volumes and prices per unit for the quarters ended March 31, 2018 and 2017. We present (i) average realized prices based on physical sales of oil, natural gas and NGLs as well as (ii) average realized prices inclusive of the impacts of financial derivative settlements and premiums which reflect cash received or paid during the respective period.

	Quarter ended March 31, 2018	Quarter ended March 31, 2017
	(in millions)	
Operating revenues:		
Oil	$252	$204
Natural gas	22	30
NGLs	26	23
Total physical sales	300	257
Financial derivatives	(14)	70
Total operating revenues	$286	$327
Volumes:		
Oil (MBbls)	4,087	4,219
Natural gas (MMcf)	11,335	11,465
NGLs (MBbls)	1,232	1,296
Equivalent volumes (MBoe)	7,208	7,426
Total MBoe/d	80.1	82.5
Prices per unit(1):		
Oil		
Average realized price on physical sales ($/Bbl)(2)	$61.56	$48.43
Average realized price, including financial derivatives ($/Bbl)(2)(3)	$58.86	$54.90
Natural gas		
Average realized price on physical sales ($/Mcf)(2)	$1.94	$2.49
Average realized price, including financial derivatives ($/Mcf)(2)(3)	$2.03	$2.46
NGLs		
Average realized price on physical sales ($/Bbl)	$20.93	$17.63
Average realized price, including financial derivatives ($/Bbl)(3)	$20.91	$17.76

(1) For both of the quarters ended March 31, 2018 and 2017, there were no oil purchases associated with managing our physical oil sales. Natural gas prices for the quarters ended March 31, 2018 and 2017 reflect operating revenues for natural gas reduced by less than $1 million and approximately $1 million, respectively, for natural gas purchases associated with managing our physical sales.

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

(3) The quarters ended March 31, 2018 and 2017, include cash paid of approximately $11 million and cash received of approximately $27 million, respectively, for the settlement of crude oil derivative contracts and approximately $1 million of cash received and less than $1 million of cash paid, respectively, for the settlement of natural gas financial derivatives. The quarters ended March 31, 2018 and 2017 also include cash paid of less than $1 million

and cash received of less than $1 million, respectively, 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 ended March 31, 2018, physical sales increased by $43 million (17%) compared to the same period in 2017. The table below displays the price and volume variances on our physical sales when comparing the quarter ended March 31, 2018 and 2017.

	Quarter ended			
	Oil	Natural gas	NGLs	Total
	(in millions)			
March 31, 2017 sales	$204	$ 30	$ 23	$257
Change due to prices	54	(8)	4	50
Change due to volumes	(6)	—	(1)	(7)
March 31, 2018 sales	$252	$ 22	$ 26	$300

Oil sales for the quarter ended March 31, 2018, compared to the same period in 2017, increased by $48 million (24%) due primarily to higher oil prices in all areas and higher oil volumes in Eagle Ford, partially offset by lower oil production in the Permian and Altamont.

Natural gas sales decreased by $8 million (27%) for the quarter ended March 31, 2018 compared to the same period in 2017 primarily due to lower natural gas prices.

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 the Permian, 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 a locational difference at the wellhead. 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.

	Quarter ended March 31,			
	2018		2017	
	Oil (Bbl)	Natural gas (MMBtu)	Oil (Bbl)	Natural gas (MMBtu)
Differentials and deducts	$(1.18)	$ (1.03)	$(3.81)	$ (0.81)
NYMEX	$62.87	$ 3.00	$51.91	$ 3.32
Net back realization %	98.1 %	65.7 %	92.7 %	75.6 %

The higher oil realization percentage in the quarter ended March 31, 2018 was primarily a result of improved physical sales contracts in Eagle Ford and improved Mid/Cushing basis spread in the Permian. The lower natural gas realization percentage in the quarter ended March 31, 2018 was primarily a result of presenting certain transportation costs as a deduction from natural gas sales beginning in 2018 due to the adoption of the new accounting standard associated with revenue recognition.

NGLs sales increased by $3 million (13%) for the quarter ended March 31, 2018 compared with the same period in 2017. Average realized prices for the quarter ended March 31, 2018 were higher compared to the same period in 2017, due to higher pricing on all liquids components. NGLs pricing is largely tied to crude oil prices.

Future growth in our overall oil, natural gas and NGLs 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 March 31, 2018, we recorded $14 million of derivative losses compared to derivative gains of $70 million during the quarter ended March 31, 2017.

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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 March 31,			
	2018		2017	
	Total	Per Unit(1)	Total	Per Unit(1)
	(in millions, except per unit costs)			
Operating expenses				
Oil and natural gas purchases	$ —	$ —	$ 1	$ 0.15
Transportation costs	25	3.43	29	3.84
Lease operating expense	39	5.48	40	5.37
General and administrative(2)	19	2.58	20	2.66
Depreciation, depletion and amortization	120	16.69	126	16.99
Exploration and other expense	1	0.18	3	0.39
Taxes, other than income taxes	20	2.75	19	2.61
Total operating expenses	$ 224	$ 31.11	$ 238	$ 32.01
Total equivalent volumes (MBoe)	7,208		7,426	

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

(2) For the quarter ended March 31, 2018, amount includes approximately $2 million or $0.27 per Boe of non-cash compensation expense. For the quarter ended March 31, 2017, amount includes approximately $(4) million or $(0.53) per Boe of non-cash compensation expense (cash payments exceeded recognized compensation expense).

Transportation costs. Transportation costs for the quarter ended March 31, 2018 decreased by $4 million compared to the same period in 2017 as a result of presenting certain transportation costs as a deduction from natural gas sales beginning in 2018 in conjunction with adopting Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers on a modified retrospective basis.

Lease operating expense. Lease operating expense decreased by $1 million for the quarter ended March 31, 2018 compared to the same period in 2017. The decrease for the quarter ended March 31, 2018 compared to 2017 is due to lower maintenance and repair costs in Altamont, partially offset by higher maintenance, repair and chemical costs in the Permian and higher compression costs in Eagle Ford. On an equivalent per unit basis, lease operating expense for the quarter ended March 31, 2018 compared to the same period in 2017 increased by 2% due to lower 2018 production volumes for the quarter ended March 31, 2018.

General and administrative expenses. General and administrative expenses for the quarter ended March 31, 2018 decreased by $1 million compared to the same period in 2017. Lower costs during the quarter ended March 31, 2018 compared to the same period in 2017 were primarily due to lower payroll and benefits costs. This decrease was offset by higher long-term incentive compensation expense in 2018 due to forfeitures we recorded during the quarter ended March 31, 2017 as a result of the departure of one of our executives. The lower payroll, benefits and administrative costs resulted from lower headcount in 2018 when compared to the same period in 2017.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense decreased for the quarter ended March 31, 2018 due primarily to lower production volumes. Our depreciation, depletion and amortization rate in the future will be impacted by the level, the location, and timing of capital spending, the overall cost of capital and the level and type of reserves recorded on completed projects. For the full year 2018, we currently anticipate our depreciation, depletion and amortization costs per unit to be between $16.50 and $17.50 per Boe. Our average depreciation, depletion and amortization costs per unit for the quarters ended March 31 were:

	Quarter ended March 31,	
	2018	2017
Depreciation, depletion and amortization ($/Boe)	$16.69	$16.99

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Other Income Statement Items.

Gain (loss) on extinguishment/modification of debt. During the first quarter of 2018, we completed an exchange of $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes maturing in May 2020, September 2022 and June 2023, respectively, for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million. In conjunction with the exchange, we recorded (i) a gain on extinguishment of debt of approximately $53 million primarily associated with retiring a portion of our 2022 and 2023 notes at less than face value (including $2 million in non-cash expense related to eliminating associated unamortized debt issue costs and debt discounts), and (ii) a loss on modification of debt of approximately $12 million associated with fees paid on the exchange of our 2020 notes.

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).

Interest expense. Interest expense for the quarter ended March 31, 2018 increased by $2 million compared to the same period in 2017 due primarily to higher average borrowings under our RBL Facility, partially offset by lower average interest rates on outstanding borrowings in 2018 compared to 2017.

Income taxes. For both of the quarters ended March 31, 2018 and 2017, our effective tax rates were approximately 0%. Our effective tax rates in 2018 and 2017 differed from the statutory rates of 21% and 35%, respectively, primarily as a result of our recognition of a full valuation allowance on our net deferred tax assets. For the quarters ended March 31, 2018 and 2017, we recorded adjustments to the valuation allowance on our net deferred tax assets, which offset deferred income tax expense by $5 million and deferred income tax benefit by $15 million, respectively.

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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) and gains and losses on extinguishment/modification of debt.

We believe that the presentation of EBITDAX and Adjusted EBITDAX is important to provide management and investors with additional information (i) to evaluate our ability to service debt adjusting for items required or permitted in calculating covenant compliance under our debt agreements, (ii) to provide an important supplemental indicator of the operational performance of our business without regard to financing methods and capital structure, (iii) for evaluating our performance relative to our peers, (iv) to measure our liquidity (before cash capital requirements and working capital needs) and (v) to provide supplemental information about certain material non-cash and/or other items that may not continue at the same level in the future. EBITDAX and Adjusted EBITDAX have limitations as analytical tools and should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP or as an alternative to net income (loss), operating income (loss), operating cash flows or other measures of financial performance or liquidity presented in accordance with GAAP.

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

	Quarter ended March 31,	
	2018	2017
	(in millions)	
Net income (loss)	$18	$(47)
Income tax expense	—	—
Interest expense, net of capitalized interest	85	83
Depreciation, depletion and amortization	120	126
Exploration expense	1	3
EBITDAX	224	165
Mark-to-market on financial derivatives(1)	14	(70)
Cash settlements and cash premiums on financial derivatives(2)	(10)	28
Non-cash portion of compensation expense(3)	2	(4)
(Gain) loss on extinguishment/modification of debt	(41)	53
Adjusted EBITDAX	$189	$172

(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 ended March 31, 2018 and 2017.

(3) There were no cash payments for the quarter ended March 31, 2018. For the quarter ended March 31, 2017, cash payments were approximately $4 million.

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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 $584 million as of March 31, 2018.

From a liquidity standpoint, our near-term strategic goal is to work towards cash flow neutrality by focusing on operating and capital efficiency, reducing cash costs and identifying accretive acquisition opportunities and divestitures while maintaining financial flexibility and managing our leverage. Our longer-term goal is to improve our cash flow to enhance our portfolio, grow our asset value and generate positive total returns for our shareholders. In the first quarter of 2018, we took a number of steps to improve our liquidity, expand our financial flexibility, and manage our leverage. These actions included exchanging $954 million, $54 million and $139 million of the outstanding amount of our senior unsecured notes maturing in May 2020, September 2022 and June 2023, respectively, for new 9.375% senior secured notes maturing in 2024 with an aggregate principal amount of approximately $1,092 million.

Availability of borrowings under our RBL Facility is an important source of liquidity for us. Our current RBL Facility will mature in May 2019 and has a borrowing base subject to semi-annual redetermination. In January 2018, as a result of the debt exchange, our borrowing base was reduced from $1.4 billion to $1.36 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, 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. Conversely, future acquisitions, reserve additions and higher prices may have the effect of increasing our borrowing base.

Our current financial covenants require us to maintain a ratio of first lien debt to EBITDAX not exceeding 3.0 to 1.0. As of March 31, 2018, we were in compliance with our debt covenants, and our ratio of first lien debt to EBITDAX was 1.09x.

In the second quarter of 2019, our RBL Facility matures and our financial covenant will revert to a 4.5 to 1.0 total net debt to EBITDAX ratio requirement, absent a renegotiation of its terms and covenants. As of March 31, 2018, our ratio of total net debt to EBITDAX was 5.93x. Based on our current outlook, including forecasted EBITDAX and expected borrowings to fund capital expenditures, we anticipate this ratio will continue to exceed the 4.5 to 1.0 total net debt to EBITDAX ratio for the remainder of 2018 and through the second quarter of 2019. We are currently working to renew and extend the RBL Facility and renegotiate the required covenants thereunder. Based on actions and negotiations to date, we believe that we will be successful in extending the RBL Facility and renegotiating its various covenants. Should we not be successful, however, we believe we have other ways to mitigate the condition, including the issuance of new debt, equity, or selling assets.

Under our various debt agreements, we are limited in our ability to repurchase certain tranches of non-RBL Facility debt. Under our new 2024 senior secured notes issued in January 2018, we are limited in our ability to repurchase certain tranches of unsecured notes and under our RBL, we are limited in our ability to repurchase certain tranches of secured and unsecured debt.

During the first quarter of 2018, we entered into transactions to enhance capital efficiency and pursue acquisitions while doing so in a cash or leverage enhancing manner, including (i) the completion of our largest acquisition to date for approximately $246 million, after customary adjustments, in the Eagle Ford while at the same time (ii) completing the sale of certain assets in Altamont for approximately $177 million, after customary closing adjustments.

To protect our cash flows and preserve our liquidity, we enter into derivative contracts on a substantial portion of our anticipated future production volumes. As of March 31, 2018, we have derivative contracts (swaps, collars and three-way collars) on 11.3 MMBbls and 2.6 MMBbls of our anticipated oil production at a weighted average price of $58.45 and $55.25 per barrel of oil for 2018 and 2019, respectively. Approximately two-thirds of these crude oil contracts will also allow for upside participation (to a weighted average price of approximately $68.15 per barrel) if prices move above current strip prices. Additionally, our 2018 three-way collar contracts contain certain sub-floor prices (weighted average prices of $50 per barrel) that limit the amount of our derivative settlements under these three-way contracts should prices drop below the sub-floor prices. For 2018 and 2019, we also have derivative swap contracts on 19 TBtu and 7 TBtu of our anticipated natural gas production at a weighted average price of $3.04 and $2.97 per MMBtu, respectively. As of March 31, 2018 based on the mid-point of our forecasted 2018 guidance, our oil and natural gas derivative contracts provide price protection on approximately

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85% and 56%, respectively, of our anticipated 2018 oil and natural gas production. Refer to Our Business for more detailed information on our derivative instruments.

For 2018, we expect to spend approximately $600 million to $650 million in capital (not including acquisition capital) in our programs. Based upon our current price and cost assumptions and our hedge program, we believe that our current capital program will exceed our estimated operating cash flows after interest payments. We believe the borrowing capacity under our RBL Facility together with expected cash flows from our operations, including cash flows generated by our recent Eagle Ford acquisition, 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.

Should commodity prices decline significantly from current levels, 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 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 debt agreements 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 quarter ended March 31, 2018 were:

	Capital Expenditures[1] (in millions)	Average Drilling Rigs
Eagle Ford Shale	$ 135	2.7
Permian	43	0.7
Altamont	30	2.0
Total	$ 208	5.4
Acquisition capital[2]	$ 248	
Total Capital Expenditures	$ 456	

(1) Represents accrual-based capital expenditures.

(2) Includes a deposit made in December 2017.

Debt. As of March 31, 2018, our total debt was approximately $4.2 billion, comprised of $29 million in senior secured term loans with maturity dates in 2018 and 2019, $775 million outstanding under the RBL Facility which matures in 2019, $822 million in senior unsecured notes due in 2020, 2022 and 2023, and $2.6 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):

	Three months ended March 31,	
	2018	2017
Cash Inflows		
Operating activities		
Net income (loss)	$18	$(47)
(Gain) loss on extinguishment/modification of debt	(41)	53
Other income adjustments	125	131
Changes in assets and liabilities	(15)	(20)
Total cash flow from operations	87	117
Investing activities		
Proceeds from the sale of assets	167	—
Cash inflows from investing activities	167	—
Financing activities		
Proceeds from issuance of long-term debt	460	1,125
Cash inflows from financing activities	460	1,125
Total cash inflows	$714	$1,242
Cash Outflows		
Investing activities		
Capital expenditures	$173	$119
Cash paid for acquisitions	223	—
Cash outflows from investing activities	396	119
Financing activities		
Repayments and repurchases of long-term debt	280	1,086
Fees/costs on debt exchange	62	—
Debt issue costs	—	19
Other	1	3
Cash outflows from financing activities	343	1,108
Total cash outflows	$739	$1,227
Net change in cash, cash equivalents and restricted cash	$(25)	$15

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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 March 31, 2018, for each of the periods presented:

	2018	2019- 2020	2021 - 2022	Thereafter	Total
			(in millions)		
Financing obligations:					
Principal	$21	$ 1,030	$ 196	$ 2,971	$4,218
Interest	243	569	518	394	1,724
Liabilities from derivatives	14	1	—	—	15
Operating leases	4	11	11	17	43
Other contractual commitments and purchase obligations:					
Volume and transportation commitments	48	119	92	7	266
Other obligations	39	32	9	—	80
Total contractual obligations	$369	$ 1,762	$ 826	$ 3,389	$6,346

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. In April 2018, we paid $21 million to retire the senior secured term loan due May 24, 2018. See Part 1, Item 1, Financial Statements, Note 7 for more information on the maturities of our long-term debt.

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

Other Contractual Commitments and Purchase Obligations. Other contractual commitments and purchase obligations are legally enforceable agreements to purchase goods or services that have fixed or minimum quantities and fixed or minimum
variable price provisions. 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 2017 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 2017 Annual Report on Form 10-K, except as presented below:

Commodity Price Risk

The table below presents the change in fair value of our commodity-based derivatives due to hypothetical changes in oil and natural gas prices, discount rates and credit rates at March 31, 2018:

	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]	$1	$(72)	$(73)	$68	$67

	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]	$1	$1	$—	$1	$—
Credit rate[3]	$1	$1	$—	$1	$—

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

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

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As of March 31, 2018, we carried out an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer (CEO) and our Chief Financial Officer (CFO), as to the effectiveness, design and operation of our disclosure controls and procedures. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the U.S. Securities and Exchange Commission reports we file or submit under the Securities Exchange Act of 1934, as amended (Exchange Act), is accurate, complete and timely. Our management, including our CEO and our CFO, does not expect that our disclosure controls and procedures or our internal controls will prevent and/or detect all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within our company have been detected. Our disclosure controls and procedures are designed to provide reasonable assurance of achieving their objectives and our CEO and CFO concluded that our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) were effective as of March 31, 2018.

Changes in Internal Control over Financial Reporting

There were no changes in EP Energy Corporation’s internal control over financial reporting during the first three months of 2018 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 2017 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 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.

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.

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Exhibit Number	Description
4.1	Indenture, dated as of January 3, 2018, by and among EP Energy LLC, Everest Acquisition Finance Inc., the Subsidiary Guarantors thereto and Wilmington Trust, National Association, as trustee and collateral agent (Exhibit 4.1 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on January 4, 2018).
10.1	Consent and Acknowledgement, dated as of January 3, 2018, by Wilmington Trust, National Association, as an Other Second-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2024 Notes, Wilmington Trust, National Association, as Term Facility Agent for the holders of the 8.00% 2025 Notes and Applicable Second Lien Agent and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Priority Lien Intercreditor Agreement dated as of August 24, 2016 and supplemented on November 29, 2016 and February 6, 2017 (Exhibit 10.1 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on January 4, 2018).
10.2	Consent and Acknowledgement, dated as of January 3, 2018, by Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent, and acknowledged by JPMorgan Chase Bank, N.A., as Applicable First Lien Agent, Wilmington Savings Fund Society, FSB (as successor to Citibank, N.A.), as Applicable Second Lien Agent, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2024 Notes, Wilmington Trust, National Association, as an Other First-Priority Lien Obligations Agent for the holders of the 8.00% 2025 Notes, and EP Energy LLC (on behalf of itself and its subsidiaries), with respect to the Amended and Restated Senior Lien Intercreditor Agreement dated as of August 24, 2016 and supplemented on November 29, 2016 and February 6, 2017 (Exhibit 10.2 to EP Energy LLC's Current Report on Form 8-K filed with the SEC on January 4, 2018).
*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.

SIGNATURES

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

EP ENERGY CORPORATION

Date: May 9, 2018 /s/ Kyle A. McCuen
Kyle A. McCuen
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: May 9, 2018 /s/ Francis C. Olmsted III
Francis C. Olmsted III
Vice President and Chief Accounting Officer
(Principal Accounting Officer)