CONCHO RESOURCES INC
Form 10-Q
August 03, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2017

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________________ to ____________________

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Concho Center 600 West Illinois Avenue Midland, Texas	**79701**
(Address of principal executive offices)	(Zip code)

(432) 683-7443

(Registrant's telephone number, including area code)

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 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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	Accelerated filer o
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

Number of shares of the registrant's common stock outstanding at July 31, 2017: 148,712,171 shares

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our future financial position, operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events and their potential effect on us. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by any forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed in "Part II, Item 1A, Risk Factors" of our Quarterly Report on Form 10-Q for the three months ended March 31, 2017 and in "Part I, Item 1A, Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2016, as well as those factors summarized below:

- declines in, or the sustained depression of, the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling, completion and operating risks;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas;
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of southeast New Mexico and west Texas;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, natural gas liquids and natural gas and other processing and transportation considerations;
- the costs and availability of equipment, resources, services and qualified personnel required to perform our drilling, completion and operating activities;
- potential financial losses or earnings reductions from our commodity price risk-management program;

- risks and liabilities associated with acquired properties or businesses;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the impact of potential changes in our credit ratings;
- cybersecurity risks, such as those involving unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks, ransomware and other security issues;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and the price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil and natural gas that are ultimately recovered.

PART I – FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

Concho Resources Inc.

Consolidated Balance Sheets

Unaudited

(in millions, except share and per share amounts)		June 30, 2017		December 31, 2016
Assets				
Current assets:				
Cash and cash equivalents	$	662	$	53
Accounts receivable, net of allowance for doubtful accounts:				
Oil and natural gas		227		220
Joint operations and other		241		238
Derivative instruments		135		4
Prepaid costs and other		39		31
Total current assets		1,304		546
Property and equipment:				
Oil and natural gas properties, successful efforts method		19,710		18,476
Accumulated depletion and depreciation		(7,904)		(7,390)
Total oil and natural gas properties, net		11,806		11,086
Other property and equipment, net		234		216
Total property and equipment, net		12,040		11,302
Funds held in escrow		60		43
Deferred loan costs, net		15		11
Intangible asset - operating rights, net		24		24
Inventory		14		16
Noncurrent derivative instruments		90		-
Other assets		44		177
Total assets	$	13,591	$	12,119
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable - trade	$	26	$	28
Revenue payable		129		132
Accrued drilling costs		446		359
Derivative instruments		-		82
Other current liabilities		165		152
Total current liabilities		766		753
Long-term debt		2,741		2,741
Deferred income taxes		1,212		766
Noncurrent derivative instruments		-		96
Asset retirement obligations and other long-term liabilities		143		140
Commitments and contingencies (Note 9)				
Stockholders' equity:				

Common stock, $0.001 par value; 300,000,000 authorized; 149,314,618 and 146,488,685 shares issued at June 30, 2017 and December 31, 2016, respectively		-		-
Additional paid-in capital		7,108		6,783
Retained earnings		1,686		884
Treasury stock, at cost; 591,650 and 429,708 shares at June 30, 2017 and December 31, 2016, respectively		(65)		(44)
Total stockholders' equity		8,729		7,623
Total liabilities and stockholders' equity	$	13,591	$	12,119

The accompanying notes are an integral part of these consolidated financial statements.

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Concho Resources Inc.

Consolidated Statements of Operations

Unaudited

(in millions, except per share amounts)	**Three Months Ended June 30, 2017**	**2016**	**Six Months Ended June 30, 2017**	**2016**
Operating revenues:				
Oil sales	$ 461	$ 339	$ 963	$ 581
Natural gas sales	106	57	216	99
Total operating revenues	567	396	1,179	680
Operating costs and expenses:				
Oil and natural gas production	100	77	187	169
Production and ad valorem taxes	44	33	92	56
Exploration and abandonments	20	21	35	44
Depreciation, depletion and amortization	281	281	564	591
Accretion of discount on asset retirement obligations	2	1	4	3
Impairments of long-lived assets	-	-	-	1,525
General and administrative (including non-cash stock-based compensation of $14 and $12 for the three months ended June 30, 2017 and 2016, respectively, and $26 and $28 for the six months ended June 30, 2017 and 2016, respectively)	60	53	116	107
(Gain) loss on derivatives	(209)	298	(495)	217
(Gain) loss on disposition of assets, net	-	1	(654)	(110)
Total operating costs and expenses	298	765	(151)	2,602
Income (loss) from operations	269	(369)	1,330	(1,922)
Other income (expense):				
Interest expense	(39)	(55)	(79)	(109)
Loss on extinguishment of debt	(1)	-	(1)	-
Other, net	16	-	16	(7)
Total other expense	(24)	(55)	(64)	(116)
Income (loss) before income taxes	245	(424)	1,266	(2,038)
Income tax (expense) benefit	(93)	158	(464)	752
Net income (loss)	$ 152	$ (266)	$ 802	$ (1,286)
Earnings per share:				
Basic net income (loss)	$ 1.02	$ (2.04)	$ 5.41	$ (9.94)
Diluted net income (loss)	$ 1.02	$ (2.04)	$ 5.39	$ (9.94)

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Consolidated Statement of Stockholders' Equity

Unaudited

(in millions, except share data)	Common Stock Issued Shares (in thousands)	Common Stock Issued Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares (in thousands)	Treasury Stock Amount	Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2016	146,489	$ -	$ 6,783	$ 884	430	$ (44)	$ 7,623
Adoption of ASU No. 2016-09 (Note 2)	-	-	8	-	-	-	8
BALANCE AT JANUARY 1, 2017	146,489	-	6,791	884	430	(44)	7,631
Net income	-	-	-	802	-	-	802
Common stock issued in business combinations	2,177	-	291	-	-	-	291
Stock options exercised	20	-	-	-	-	-	-
Grants of restricted stock	439	-	-	-	-	-	-
Performance unit share conversion	249	-	-	-	-	-	-
Cancellation of restricted stock	(59)	-	-	-	-	-	-
Stock-based compensation	-	-	26	-	-	-	26
Purchase of treasury stock	-	-	-	-	162	(21)	(21)
BALANCE AT JUNE 30, 2017	149,315	$ -	$ 7,108	$ 1,686	592	$ (65)	$ 8,729

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Consolidated Statements of Cash Flows

Unaudited

	Six Months Ended June 30,	
(in millions)	**2017**	**2016**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ 802	$ (1,286)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	564	591
Accretion of discount on asset retirement obligations	4	3
Impairments of long-lived assets	-	1,525
Exploration and abandonments, including dry holes	24	39
Non-cash stock-based compensation expense	26	28
Deferred income taxes	454	(740)
Gain on disposition of assets, net	(654)	(110)
(Gain) loss on derivatives	(495)	217
Net settlements received from derivatives	96	427
Loss on extinguishment of debt	1	-
Other non-cash items	1	8
Changes in operating assets and liabilities, net of acquisitions and dispositions:		
Accounts receivable	(24)	60
Prepaid costs and other	(3)	(9)
Inventory	1	3
Accounts payable	(2)	7
Revenue payable	(2)	(59)
Other current liabilities	12	(28)
Net cash provided by operating activities	805	676
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and natural gas properties	(863)	(651)
Additions to property, equipment and other assets	(30)	(16)
Proceeds from the disposition of assets	803	294
Direct transaction costs for disposition of assets	(18)	-
Funds held in escrow	(60)	-
Contributions to equity method investments	-	(39)
Net cash used in investing activities	(168)	(412)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of debt	105	-
Payments of debt	(105)	-
Excess tax deficiency from stock-based compensation (Note 2)	-	(1)
Payments for loan costs	(7)	-
Purchase of treasury stock	(21)	(11)
Net cash used in financing activities	(28)	(12)
Net increase in cash and cash equivalents	609	252

Cash and cash equivalents at beginning of period		53		229
Cash and cash equivalents at end of period	$	662	$	481
NON-CASH INVESTING AND FINANCING ACTIVITIES:				
Issuance of common stock for business combinations	$	291	$	231

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

Unaudited

Note 1. ***Organization and nature of operations***

Concho Resources Inc. (the “Company”) is a Delaware corporation formed on February 22, 2006. The Company’s principal business is the acquisition, development, exploration and production of oil and natural gas properties primarily located in the Permian Basin of southeast New Mexico and west Texas.

Note 2. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its 100 percent owned subsidiaries. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2017 presentation. These reclassifications had no impact on net income (loss), total stockholders’ equity or total cash flows.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves, commodity price outlooks and prevailing market rates of other sources of income and costs. Other significant estimates include, but are not limited to, asset retirement obligations, fair value of stock-based compensation, fair value of business combinations, fair value of nonmonetary exchanges, fair value of derivative financial instruments and income taxes.

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company's independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2016 is derived from audited consolidated financial statements. In the opinion of management, the accompanying consolidated financial statements reflect all adjustments necessary to present fairly the Company's consolidated financial statements. All such adjustments are of a normal, recurring nature. In preparing the accompanying consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed in or omitted from these consolidated financial statements. Accordingly, these condensed notes to the consolidated financial statements should be read in conjunction with the audited consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2016.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected. The majority of the Company's cash is invested in stable value government money market funds.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

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Unaudited

Equity method investments. At December 31, 2016, the Company owned a 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), that operated a crude oil gathering and transportation system in the northern Delaware Basin. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. See Note 4 for additional information regarding the disposition of ACC.

The Company accounted for its investment in ACC under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment in ACC was approximately $129 million at December 31, 2016, and was included in other assets in the Company's consolidated balance sheet. Gains and losses incurred from the Company's equity investment in ACC were recorded in other income (expense) in its consolidated statements of operations.

The Company owns a 23.75 percent membership interest in an entity that operates a crude oil gathering and transportation system in the southern Delaware Basin. The Company accounts for its investment under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment was approximately $45 million and $42 million at June 30, 2017 and December 31, 2016, respectively, and is included in other assets in the Company's consolidated balance sheets. Gains and losses incurred from the Company's equity investment are recorded in other income (expense) in its consolidated statements of operations.

Revenue recognition. Oil and natural gas revenues are recorded at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company's actual proceeds from the oil and natural gas sold to purchasers.

General and administrative expense. The Company receives fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and records such reimbursements as reductions of general and administrative expense. The Company earned reimbursements of approximately $4 million for each of the three months ended June 30, 2017 and 2016 and $8 million for each of the six months ended June 30, 2017 and 2016.

Recently adopted accounting pronouncements. The Company adopted Accounting Standards Update ("ASU") No. 2016-09, "Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting," on January 1, 2017. The adoption did not have an impact on prior period consolidated financial statements. The Company elected to account for forfeitures of share-based payments as they occur. At December 31, 2016, the Company had not recorded compensation expense of approximately $8 million based on forecasted forfeitures nor the associated deferred tax benefit of approximately $3 million. The Company recognized all excess tax benefits not previously recorded, which totaled approximately $5 million at December 31, 2016. Upon adoption, the Company recorded a cumulative-effect adjustment, which decreased retained earnings by less than $1 million, increased additional paid-in capital by approximately $8 million, and decreased net deferred income taxes by approximately $8 million. The Company elected to prospectively classify excess tax benefits and deficiencies as operating activities on the consolidated statements of cash flows and will prospectively record those excess tax benefits and deficiencies as discrete items in the income tax provision in the consolidated statements of operations. Under the new standard, for the three and six months ended June 30, 2017, the Company recorded excess tax deficiencies of approximately $2 million and excess tax benefits of approximately $6 million, respectively, as offsets to the Company’s income tax provision. Also under the new standard, for the three and six months ended June 30, 2017, the Company recorded forfeitures of share-based payments of approximately $1 million and $6 million, respectively.

New accounting pronouncements issued but not yet adopted. In May 2014, the Financial Accounting Standards Board (the “FASB”) issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606),” which outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

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In August 2015, the FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date," which deferred the effective date of ASU No. 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. The Company expects to use the modified retrospective method to adopt the standard, meaning the cumulative effect of initially applying the standard will be recognized in the most current period presented in the financial statements. The Company has substantially completed its internal evaluation of the adoption of this standard and does not expect this new guidance will have a material impact on its consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for financing and operating leases. Lease expense recognition on the consolidated statements of operations will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018, and early adoption is permitted. The Company does not plan to early adopt the standard. The Company enters into lease agreements to support its operations. These agreements are for leases on assets such as office space, vehicles, field services, well equipment and drilling rigs. The Company is currently in the process of reviewing all contracts that could be applicable to this new guidance. The Company believes this new guidance will have a moderate impact to its consolidated balance sheets due to the recognition of right-of-use assets and lease liabilities that are not currently recognized under currently applicable guidance.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments–Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments," which replaces the current "incurred loss" methodology for recognizing credit losses with an "expected loss" methodology. This new methodology requires that a financial asset measured at amortized cost be presented at the net amount expected to be collected. This standard is intended to provide more timely decision-useful information about the expected credit losses on financial instruments. This guidance is effective for fiscal years beginning after December 15, 2019, and early adoption is allowed as early as fiscal years beginning after December 15, 2018. The Company does not believe this new guidance will have a material impact on its consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. This new guidance is effective for annual periods beginning after December 15, 2017, and early adoption is allowed. The Company is evaluating the impact this new guidance will have on its consolidated financial statements. The new guidance could result in more acquisitions of oil and natural gas properties being accounted for as asset acquisitions instead of business combinations.

Concho Resources Inc.

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Note 3. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. After an exploratory well has been completed and found oil and natural gas reserves, a determination may be pending as to whether the oil and natural gas reserves can be classified as proved. In those circumstances, the Company continues to capitalize the well or project costs pending the determination of proved status if (i) the well has found a sufficient quantity of reserves to justify its completion as a producing well and (ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Note 15 for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense in the consolidated statements of operations.

The following table reflects the Company’s net capitalized exploratory well activity during the six months ended June 30, 2017:

(in millions)		**Six Months Ended June 30, 2017**
Beginning capitalized exploratory well costs	$	151
Additions to exploratory well costs pending the determination of proved reserves		268
Reclassifications due to determination of proved reserves		(126)
Ending capitalized exploratory well costs	$	293

The following table provides an aging at June 30, 2017 and December 31, 2016 of capitalized exploratory well costs based on the date drilling was completed:

	June 30,	**December 31,**

(dollars in millions)		**2017**		**2016**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$	288	$	141
Capitalized exploratory well costs that have been capitalized for a period greater than one year		5		10
Total capitalized exploratory well costs	$	293	$	151
Number of projects with exploratory well costs that have been capitalized for a period greater than one year		6		8

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

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Note 4. ***Acquisitions and divestitures***

Northern Delaware Basin acquisition. In April 2017, the Company closed on the remainder of its acquisition in the Northern Delaware Basin. As consideration for the entire acquisition, the Company paid approximately $159 million in cash, of which $43 million was held in escrow at December 31, 2016, and issued to the seller approximately 2.2 million shares of its common stock with an approximate value of $291 million. The acquisition is subject to customary post-closing adjustments.

ACC divestiture. In February 2017, the Company closed on the divestiture of its ownership interest in ACC. The Company and its joint venture partner entered into separate agreements to sell 100 percent of their respective ownership interests in ACC. After adjustments for debt and working capital, the Company received cash proceeds from the sale of approximately $803 million. After direct transaction costs, the Company recorded a pre-tax gain on disposition of assets of approximately $655 million. The Company’s net investment in ACC at the time of closing was approximately $129 million.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

Unaudited

Note 5. ***Stock incentive plan***

The Company’s 2015 Stock Incentive Plan provides for granting stock options, restricted stock awards and performance awards to directors, officers and employees of the Company. The restricted stock-based compensation awards generally vest over a period ranging from one to eight years.

A summary of the Company’s Stock Incentive Plan activity for the six months ended June 30, 2017 is presented below:

	Restricted Stock Shares	Stock Options	Performance Units
Outstanding at December 31, 2016	1,157,270	20,000	331,526
Awards granted (a)	439,484	-	108,398
Options exercised	-	(20,000)	-
Awards cancelled / forfeited	(59,614)	-	(43,333)
Lapse of restrictions	(354,909)	-	-
Outstanding at June 30, 2017	1,182,231	-	396,591
(a) Weighted average grant date fair value per share/unit	$ 121.81	$ -	$ 183.48

The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at June 30, 2017:

(in millions)	
Remaining 2017	$ 35
2018	48
2019	25

Thereafter		8
Total	$	116

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Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

Unaudited

Note 6. ***Disclosures about fair value measurements***

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1**:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2**:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Level 3**:** Prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

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Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at June 30, 2017 and December 31, 2016:

	June 30, 2017		December 31, 2016	
(in millions)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Assets:				
Derivative instruments	$ 225	$ 225	$ 4	$ 4
Liabilities:				
Derivative instruments	$ -	$ -	$ 178	$ 178
$600 million 5.5% senior notes due 2022 (a)	$ 594	$ 619	$ 594	$ 620
$1,550 million 5.5% senior notes due 2023 (a)	$ 1,554	$ 1,597	$ 1,555	$ 1,621
$600 million 4.375% senior notes due 2025 (a)	$ 593	$ 614	$ 592	$ 599

(a) The carrying value includes associated deferred loan costs and any premium.

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

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Derivative instruments. The fair value of the Company’s derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company’s financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company’s consolidated balance sheets at June 30, 2017 and December 31, 2016. The Company nets the fair value of derivative instruments by counterparty in the Company’s consolidated balance sheets.

	June 30, 2017 Fair Value Measurements Using					
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Net Fair Value Presented in the Consolidated Balance Sheet
Assets:						
Current:						
Commodity derivatives	$ -	$ 145	$ -	$ 145	$ (10)	$ 135
Noncurrent:						
Commodity derivatives	-	94	-	94	(4)	90
Liabilities:						
Current:						
Commodity derivatives	-	(10)	-	(10)	10	-
Noncurrent:						
	-	(4)	-	(4)	4	-

Commodity derivatives												
Net derivative instruments	$	-	$	225	$	-	$	225	$	-	$	225

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	December 31, 2016					
	Fair Value Measurements Using					Net
(in millions)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets:						
Current:						
Commodity derivatives	$ -	$ 59	$ -	$ 59	$ (55)	$ 4
Noncurrent:						
Commodity derivatives	-	-	-	-	-	-
Liabilities:						
Current:						
Commodity derivatives	-	(137)	-	(137)	55	(82)
Noncurrent:						
Commodity derivatives	-	(96)	-	(96)	-	(96)
Net derivative instruments	$ -	$ (174)	$ -	$ (174)	$ -	$ (174)

Concentrations of credit risk. At June 30, 2017, the Company's primary concentrations of credit risk are the risk of collecting accounts receivable and the risk of counterparties' failure to perform under derivative obligations.

The Company has entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set-off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 7 for additional information regarding the Company’s derivative activities and counterparties.

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company’s consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company periodically reviews its long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. The Company reviews its oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of the Company’s assets, it recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

The Company calculates the expected undiscounted future net cash flows of its long-lived assets and their integrated assets using management’s assumptions and expectations of (i) commodity prices, which are based on the New York Mercantile Exchange (“NYMEX”) strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At June 30, 2017, the Company’s estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $45.26 per barrel of oil to a 2024 price of $53.68 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.16 per Mcf of natural gas decreasing to a 2020 price of $2.83 per Mcf partially recovering to a 2024 price of $3.03 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

The Company calculates the estimated fair values of its long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) a discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value. These are classified as Level 3 fair value assumptions.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of the Company's Yeso field of approximately $3.4 billion exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The non-cash charge represented the amount by which the carrying amount exceeded the estimated fair value of the assets.

The following table reports the carrying amount, estimated fair value and impairment expense of long-lived assets for the indicated period:

(in millions)	**Carrying Amount**	**Estimated Fair Value (Level 3)**	**Impairment Expense**
March 2016	$ 3,438	$ 1,913	$ 1,525

It is reasonably possible that the estimate of undiscounted future net cash flows of the Company's long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity prices including differentials, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) changes in income and expenses from integrated assets.

Note 7. ***Derivative financial instruments***

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company also enters into fixed-price forward physical power purchase contracts to manage the volatility of the price of power needed for ongoing operations. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these physical contracts are not expected to be net cash settled, the Company has elected normal purchase or normal sale treatment and are thus recorded at cost.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its consolidated statements of operations as they occur.

The following table summarizes the amounts reported in earnings related to the commodity derivative instruments for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**
Gain (loss) on derivatives:				
Oil derivatives	$ 199	$ (281)	$ 465	$ (209)

Natural gas derivatives		10		(17)		30		(8)
Total	$	209	$	(298)	$	495	$	(217)

The following table represents the Company’s net cash receipts from (payments on) derivatives for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,				Six Months Ended June 30,			
(in millions)	**2017**		**2016**		**2017**		**2016**	
Net cash receipts from (payments on) derivatives:								
Oil derivatives	$	70	$	160	$	101	$	412
Natural gas derivatives		(2)		8		(5)		15
Total	$	68	$	168	$	96	$	427

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Commodity derivative contracts at June 30, 2017. The following table sets forth the Company's outstanding derivative contracts at June 30, 2017. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at June 30, 2017 are expected to settle by December 31, 2019.

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
Oil Price Swaps: (a)					
2017:					
Volume (Bbl)			7,966,370	7,188,080	15,154,450
Price per Bbl			$ 51.69	$ 51.87	$ 51.77
2018:					
Volume (Bbl)	6,581,629	6,131,170	5,765,318	5,455,007	23,933,124
Price per Bbl	$ 52.01	$ 51.84	$ 51.68	$ 51.54	$ 51.78
2019:					
Volume (Bbl)	3,772,000	3,604,000	3,460,000	3,324,000	14,160,000
Price per Bbl	$ 53.60	$ 53.58	$ 53.59	$ 53.61	$ 53.59
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)			6,302,000	6,302,000	12,604,000
Price per Bbl			$ (0.57)	$ (0.57)	$ (0.57)
2018:					
Volume (Bbl)	6,586,000	6,156,000	5,765,000	5,488,000	23,995,000
Price per Bbl	$ (1.05)	$ (1.04)	$ (1.04)	$ (1.04)	$ (1.04)
2019:					
Volume (Bbl)	3,771,000	3,609,000	3,434,000	3,311,000	14,125,000
Price per Bbl	$ (1.18)	$ (1.18)	$ (1.19)	$ (1.19)	$ (1.19)
Natural Gas Price Swaps: (c)					
2017:					
Volume (MMBtu)			15,895,441	14,673,000	30,568,441
Price per MMBtu			$ 3.12	$ 3.10	$ 3.11
2018:					
Volume (MMBtu)	11,156,000	10,641,000	10,219,000	9,904,000	41,920,000
Price per MMBtu	$ 3.06	$ 3.05	$ 3.05	$ 3.04	$ 3.05
2019:					
Volume (MMBtu)	2,791,533	2,681,387	2,578,537	2,489,535	10,540,992
Price per MMBtu	$ 2.86	$ 2.85	$ 2.85	$ 2.85	$ 2.85

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the creditworthiness of counterparties to its derivative instruments. The Company believes that all of its derivative counterparties are currently acceptable credit risks. Other than provided by the Company's credit facility, the Company is not required to provide credit support or collateral to any counterparties under its derivative contracts, nor are they required to provide credit support to the Company. Under the terms of the Company's credit facility, certain events could occur that would cause any obligations under the Company's credit facility to no longer be secured by the Company's oil and natural gas properties.

At June 30, 2017, the Company had a net asset position of $225 million as a result of outstanding derivative contracts which are reflected in the accompanying consolidated balance sheets. The Company assessed this balance for concentration risk and noted balances of approximately $32 million, $32 million, $24 million, $22 million and $20 million with Wells Fargo Bank, N.A., J.P. Morgan Chase Bank, Citibank, N.A., ING Bank and Societe Generale, respectively.

Note 8. ***Debt***

The Company's debt consisted of the following at June 30, 2017 and December 31, 2016:

(in millions)	**June 30, 2017**	**December 31, 2016**
Credit facility	$ -	$ -
5.5% unsecured senior notes due 2022	600	600
5.5% unsecured senior notes due 2023	1,550	1,550
4.375% unsecured senior notes due 2025	600	600
Unamortized original issue premium	21	22
Senior notes issuance costs, net	(30)	(31)
Less: current portion	-	-
Total long-term debt	$ 2,741	$ 2,741

Credit facility. In April 2017, the Company amended its credit facility to extend the maturity date, decrease unused lender commitments and increase the borrowing base. As a result, the Company recorded a loss on extinguishment of debt of approximately $1 million for the three and six months ended June 30, 2017, representing the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the credit facility syndicate. The Company's credit facility, as amended and restated, has a maturity date of May 9, 2022. At June 30, 2017, the Company's commitments from its bank group were $2.0 billion and its borrowing base was $3.0 billion.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by all subsidiaries of the Company, subject to customary release provisions as described in Note 13.

At June 30, 2017, the Company was in compliance with the covenants under all of its debt instruments.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at June 30, 2017 were as follows:

(in millions)		
Remaining 2017	$	-
2018		-
2019		-
2020		-
2021		-
2022		600
Thereafter		2,150
Total	$	2,750

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Interest expense. The following amounts have been incurred and charged to interest expense for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**
Cash payments for interest	$ 4	$ 64	$ 65	$ 106
Non-cash interest	1	1	4	4
Net changes in accruals	34	(10)	10	(1)
Total interest expense	$ 39	$ 55	$ 79	$ 109

Note 9. *Commitments and contingencies*

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Severance tax, royalty and joint interest audits. The Company is subject to routine severance, royalty and joint interest audits from regulatory bodies and non-operators and makes accruals as necessary for estimated exposure when deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise primarily from interpretations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, allowable costs under joint interest arrangements and other matters. At December 31, 2016, the Company had $7 million accrued for estimated exposure that has since been satisfied. Although the Company believes that it has estimated its exposure with respect to the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

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Commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds. These contractual arrangements relate to purchase agreements the Company has entered into including drilling commitments, water commitment agreements, throughput volume delivery commitments, power commitments, fixed asset commitments and maintenance commitments. The following table summarizes the Company’s commitments at June 30, 2017:

(in millions)		
Remaining 2017	$	24
2018		51
2019		53
2020		26
2021		22
2022		23
Thereafter		84
Total	$	283

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the three months ended June 30, 2017 and 2016 were approximately $3 million and $2 million, respectively, and approximately $5 million and $4 million for the six months ended June 30, 2017 and 2016, respectively.

Future minimum lease commitments under non-cancellable operating leases at June 30, 2017 were as follows:

(in millions)		
Remaining 2017	$	5
2018		9
2019		7
2020		6
2021		4

2022		-
Thereafter		1
Total	$	32

Note 10. ***Income taxes***

The effective income tax rates were 37.8 percent and 37.3 percent for the three months ended June 30, 2017 and 2016, respectively, and 36.6 percent and 36.9 percent for the six months ended June 30, 2017 and 2016, respectively. Total income tax expense for the three and six months ended June 30, 2017 differed from amounts computed by applying the United States federal statutory tax rates to pre-tax income primarily due to state income taxes and the impact of permanent differences between book and taxable income. The Company recorded discrete income tax expense of approximately $2 million and a discrete income tax benefit of approximately $6 million for the three and six months ended June 30, 2017, respectively, related to excess tax deficiencies (benefits) on stock-based awards, which are recorded in the income tax provision pursuant to ASU No. 2016-09, which was adopted on January 1, 2017. Total income tax benefit for the three and six months ended June 30, 2016 differed from amounts computed by applying the United States federal statutory tax rates to pre-tax loss primarily due to state income taxes, partially offset by the impact of permanent differences between book and taxable loss.

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Note 11. ***Related party transactions***

The Company paid royalties on certain properties to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest. These payments were reported in the Company's consolidated statements of operations and totaled approximately $2 million and $1 million for the three months ended June 30, 2017 and 2016, respectively, and approximately $4 million and $2 million for the six months ended June 30, 2017 and 2016, respectively.

Note 12. ***Earnings per share***

The Company uses the two-class method of calculating earnings per share because certain of the Company's unvested share-based awards qualify as participating securities.

The Company's basic earnings per share attributable to common stockholders is computed as (i) net income (loss) as reported, (ii) less participating basic earnings (iii) divided by weighted average basic common shares outstanding. The Company's diluted earnings per share attributable to common stockholders is computed as (i) basic earnings attributable to common stockholders, (ii) plus reallocation of participating earnings (iii) divided by weighted average diluted common shares outstanding.

The following table reconciles the Company's earnings from operations and earnings attributable to common stockholders to the basic and diluted earnings used to determine the Company's earnings per share amounts for the three and six months ended June 30, 2017 and 2016, respectively, under the two-class method:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**
Net income (loss) as reported	$ 152	$ (266)	$ 802	$ (1,286)

Participating basic earnings (a)		(1)		-		(6)		-
Basic earnings attributable to common stockholders		151		(266)		796		(1,286)
Reallocation of participating earnings		-		-		-		-
Diluted earnings attributable to common stockholders	$	151	$	(266)	$	796	$	(1,286)

(a) Unvested restricted stock awards represent participating securities because they participate in nonforfeitable dividends or distributions with the common equity holders of the Company. Participating earnings represent the distributed earnings of the Company attributable to the participating securities. Unvested restricted stock awards do not participate in undistributed net losses as they are not contractually obligated to do so.

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The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2017**	**2016**	**2017**	**2016**
Weighted average common shares outstanding:				
Basic	147,304	130,400	147,071	129,398
Dilutive common stock options	-	-	6	-
Dilutive performance units	462	-	581	-
Diluted	147,766	130,400	147,658	129,398

The following table is a summary of the performance units that were not included in the computation of diluted earnings per share, as inclusion of these items would be antidilutive:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2017**	**2016**	**2017**	**2016**
Number of antidilutive units:				
Antidilutive performance units	107	-	108	-

Performance unit awards. The number of shares of common stock that will ultimately be issued for performance units will be determined by a combination of (i) comparing the Company's total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company's absolute total shareholder return at the end of the performance period. The performance period is 36 months. The actual payout of shares will be between zero and 300 percent.

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Note 13. ***Subsidiary guarantors***

All of the Company’s 100 percent owned subsidiaries have fully and unconditionally guaranteed the Company’s senior notes. The indentures governing the Company’s senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note 8 for a summary of the Company’s senior notes. In accordance with practices accepted by the United States Securities and Exchange Commission, the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors.

The following condensed consolidating balance sheets at June 30, 2017 and December 31, 2016, condensed consolidating statements of operations for the three and six months ended June 30, 2017 and 2016 and condensed consolidating statements of cash flows for the six months ended June 30, 2017 and 2016, present financial information for Concho Resources Inc. as the parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors are not restricted from making distributions to the Company.

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Condensed Consolidating Balance Sheet
June 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,986	$ (639)	$ (8,347)	$ -
Other current assets	167	1,137	-	1,304
Oil and natural gas properties, net	-	11,806	-	11,806
Property and equipment, net	-	234	-	234
Investment in subsidiaries	2,831	-	(2,831)	-
Other long-term assets	105	142	-	247
Total assets	$ 12,089	$ 12,680	$ (11,178)	$ 13,591
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ (639)	$ 8,986	$ (8,347)	$ -
Other current liabilities	46	720	-	766
Long-term debt	2,741	-	-	2,741
Other long-term liabilities	1,212	143	-	1,355
Equity	8,729	2,831	(2,831)	8,729
Total liabilities and equity	$ 12,089	$ 12,680	$ (11,178)	$ 13,591

Condensed Consolidating Balance Sheet
December 31, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,991	$ (336)	$ (8,655)	$ -
Other current assets	12	534	-	546
Oil and natural gas properties, net	-	11,086	-	11,086
Property and equipment, net	-	216	-	216
Investment in subsidiaries	1,989	-	(1,989)	-
Other long-term assets	11	260	-	271

Total assets	$	11,003	$	11,760	$	(10,644)	$	12,119
LIABILITIES AND EQUITY								
Accounts payable - related parties	$	(336)	$	8,991	$	(8,655)	$	-
Other current liabilities		114		639		-		753
Long-term debt		2,741		-		-		2,741
Other long-term liabilities		861		141		-		1,002
Equity		7,623		1,989		(1,989)		7,623
Total liabilities and equity	$	11,003	$	11,760	$	(10,644)	$	12,119

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Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 567	$ -	$ 567
Total operating costs and expenses	210	(508)	-	(298)
Income from operations	210	59	-	269
Interest expense	(38)	(1)	-	(39)
Loss on extinguishment of debt	(1)	-	-	(1)
Other, net	74	16	(74)	16
Income before income taxes	245	74	(74)	245
Income tax expense	(93)	-	-	(93)
Net income	$ 152	$ 74	$ (74)	$ 152

Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 396	$ -	$ 396
Total operating costs and expenses	(297)	(468)	-	(765)
Loss from operations	(297)	(72)	-	(369)
Interest expense	(54)	(1)	-	(55)
Other, net	(73)	-	73	-
Loss before income taxes	(424)	(73)	73	(424)
Income tax benefit	158	-	-	158
Net loss	$ (266)	$ (73)	$ 73	$ (266)

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Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 1,179	$ -	$ 1,179
Total operating costs and expenses	495	(344)	-	151
Income from operations	495	835	-	1,330
Interest expense	(78)	(1)	-	(79)
Loss on extinguishment of debt	(1)	-	-	(1)
Other, net	850	16	(850)	16
Income before income taxes	1,266	850	(850)	1,266
Income tax expense	(464)	-	-	(464)
Net income	$ 802	$ 850	$ (850)	$ 802

Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 680	$ -	$ 680
Total operating costs and expenses	(218)	(2,384)	-	(2,602)
Loss from operations	(218)	(1,704)	-	(1,922)
Interest expense	(107)	(2)	-	(109)
Other, net	(1,713)	(7)	1,713	(7)
Loss before income taxes	(2,038)	(1,713)	1,713	(2,038)
Income tax benefit	752	-	-	752
Net loss	$ (1,286)	$ (1,713)	$ 1,713	$ (1,286)

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Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

Unaudited

Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2017

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 28	$ 777	$ -	$ 805
Net cash flows used in investing activities	-	(168)	-	(168)
Net cash flows used in financing activities	(28)	-	-	(28)
Net increase in cash and cash equivalents	-	609	-	609
Cash and cash equivalents at beginning of period	-	53	-	53
Cash and cash equivalents at end of period	$ -	$ 662	$ -	$ 662

Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2016

(in millions)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by operating activities	$ 12	$ 664	$ -	$ 676
Net cash flows used in investing activities	-	(412)	-	(412)
Net cash flows used in financing activities	(12)	-	-	(12)
	-	252	-	252

Net increase in cash and cash equivalents				
Cash and cash equivalents at beginning of period	-	229	-	229
Cash and cash equivalents at end of period	$ -	$ 481	$ -	$ 481

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Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

Unaudited

Note 14. ***Subsequent events***

Midland Basin acquisition. In July 2017, the Company completed an acquisition in the Midland Basin. As consideration for the acquisition, the Company paid approximately $600 million in cash, of which $60 million was held in escrow at June 30, 2017 with the remaining $540 million paid in July 2017. The acquisition is subject to customary post-closing adjustments.

New commodity derivative contracts. After June 30, 2017, the Company entered into the following oil price swaps and oil basis swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2017:					
Volume (Bbl)			1,253,000	1,354,000	2,607,000
Price per Bbl			$ 47.76	$ 47.73	$ 47.74
2018:					
Volume (Bbl)	1,059,000	869,000	747,000	669,000	3,344,000
Price per Bbl	$ 48.33	$ 48.26	$ 48.20	$ 48.15	$ 48.25
2019:					
Volume (Bbl)	1,002,000	940,000	885,000	845,000	3,672,000
Price per Bbl	$ 49.26	$ 49.24	$ 49.27	$ 49.26	$ 49.26
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)			915,000	1,380,000	2,295,000
Price per Bbl			$ (1.28)	$ (1.28)	$ (1.28)
2018:					
Volume (Bbl)	630,000	637,000	644,000	644,000	2,555,000
Price per Bbl	$ (1.11)	$ (1.11)	$ (1.11)	$ (1.11)	$ (1.11)
2019:					
Volume (Bbl)	810,000	819,000	828,000	828,000	3,285,000
Price per Bbl	$ (1.12)	$ (1.12)	$ (1.12)	$ (1.12)	$ (1.12)

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2017

Unaudited

Note 15. ***Supplementary information***

Capitalized costs

(in millions)	**June 30, 2017**	**December 31, 2016**
Oil and natural gas properties:		
Proved	$ 17,364	$ 16,620
Unproved	2,346	1,856
Less: accumulated depletion	(7,904)	(7,390)
Net capitalized costs for oil and natural gas properties	$ 11,806	$ 11,086

Costs incurred for oil and natural gas producing activities

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(in millions)	**2017**	**2016**	**2017**	**2016**
Property acquisition costs:				
Proved	$ 12	$ 4	$ 139	$ 256
Unproved	87	19	393	158
Exploration	238	165	473	336
Development	145	107	303	190
Total costs incurred for oil and natural gas properties	$ 482	$ 295	$ 1,308	$ 940

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from those implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploration and production of oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of southeast New Mexico and west Texas. Concho's legacy in the Permian Basin provides us a deep understanding of operating and geological trends. We are actively applying new technologies, such as extended length lateral drilling, multi-well pad development and enhanced completion techniques, throughout our four core operating areas: the Northern Delaware Basin, the Southern Delaware Basin, the Midland Basin and the New Mexico Shelf. Oil comprised 59 percent of our 720 MMBoe of estimated proved reserves at December 31, 2016 and 62 percent of our 183,036 Boe of average daily production for the six months ended June 30, 2017. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 92 percent of our proved developed producing reserves and 79 percent of our 7,858 gross wells at December 31, 2016. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Financial and Operating Performance

Our financial and operating performance for the six months ended June 30, 2017 and 2016 included the following highlights:

- Net income was $802 million ($5.39 per diluted share) as compared to net loss of $1.3 billion ($(9.94) per diluted share) for the first six months of 2017 and 2016, respectively. The increase was primarily due to:

- no recorded impairments of long-lived assets during the six months ended June 30, 2017, as compared to $1.5 billion in non-cash impairment charges in 2016, primarily attributable to properties in our New Mexico Shelf area;

- $712 million change in (gain) loss on derivatives due to a $495 million gain on derivatives during the six months ended June 30, 2017, as compared to a $217 million loss on derivatives during 2016;

- gain on disposition of assets, net increased $544 million primarily due to our disposition of Alpha Crude Connector, LLC (“ACC”) which resulted in a gain of approximately $655 million during the six months ended June 30, 2017, as compared to a gain of approximately $110 million during 2016 primarily attributable to our Northern Delaware Basin divestiture in February 2016;

- $499 million increase in oil and natural gas revenues as a result of a 36 percent increase in commodity price realizations per Boe (excluding the effects of derivative activities) and a 29 percent increase in production; and

- $27 million decrease in depreciation, depletion and amortization expense, primarily due to a decrease in the depletion rate per Boe period over period, partially offset by an increase in production;

partially offset by:

- $1.2 billion change in our income tax provision due to income before income taxes during the six months ended June 30, 2017, as compared to a loss before income taxes during 2016; and

- $36 million increase in production and ad valorem tax expense, primarily due to increased production taxes as a result of increased oil and natural gas sales.

- Average daily sales volumes of 183,036 Boe per day during the first six months of 2017 increased 29 percent as compared to 142,319 Boe per day during 2016.

- Net cash provided by operating activities increased by approximately $129 million to $805 million for the first six months of 2017, as compared to $676 million in the first six months of 2016, primarily due to an increase in oil and natural gas revenues and decreased cash interest expense, partially offset by (i) a decrease in cash settlements on derivatives, (ii) increased production tax expense, (iii) changes related to cash income taxes and (iv) increased production expense.

- Cash increased by approximately $609 million during the first six months of 2017 primarily as a result of proceeds from our February 2017 divestiture of ACC. In July 2017, we paid approximately $540 million in cash as partial consideration for our Midland Basin acquisition.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, natural gas and natural gas liquids, (ii) market uncertainty and (iii) a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids, include, but are not limited to:

- continuing economic uncertainty worldwide;

- political and economic developments in oil and natural gas producing regions, including Africa, South America and the Middle East;

- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to influence global oil supply levels;

- technological advances affecting energy consumption and energy supply;

- domestic and foreign governmental regulations, including limits on the United States' ability to export crude oil, and taxation;

- the level of global inventories;

- the proximity, capacity, cost and availability of pipelines and other transportation facilities, as well as the availability of commodity processing and gathering and refining capacity;

- risks related to the concentration of our operations in the Permian Basin of southeast New Mexico and west Texas and the level of commodity inventory in the Permian Basin;

- the quality of the oil we produce;

- the overall global demand for oil, natural gas and natural gas liquids;

- the domestic and foreign supply of oil, natural gas and natural gas liquids;

- political and economic events that directly or indirectly impact the relative strength or weakness of the United States dollar, on which oil prices are benchmarked globally, against foreign currencies;

- the effect of energy conservation efforts;

- the price and availability of alternative fuels; and

- overall North American oil, natural gas and natural gas liquids supply and demand fundamentals, including:

- the United States economy,

- weather conditions, and

• liquefied natural gas deliveries to and exports from the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Notes 7 and 14 of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our commodity derivative positions at June 30, 2017 and additional derivative contracts entered into subsequent to June 30, 2017, respectively.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. The average oil and natural gas prices were higher during the comparable periods of 2017 measured against 2016. The following table sets forth the average New York Mercantile Exchange ("NYMEX") oil and natural gas prices for the three and six months ended June 30, 2017 and 2016, as well as the high and low NYMEX prices for the same periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	**2016**	**2017**	**2016**
Average NYMEX prices:				
Oil (Bbl)	$ 48.32	$ 45.56	$ 50.12	$ 39.65
Natural gas (MMBtu)	$ 3.15	$ 2.24	$ 3.12	$ 2.12
High and Low NYMEX prices:				
Oil (Bbl):				
High	$ 53.40	$ 51.23	$ 54.45	$ 51.23
Low	$ 42.53	$ 35.70	$ 42.53	$ 26.21
Natural gas (MMBtu):				
High	$ 3.42	$ 2.92	$ 3.72	$ 2.92
Low	$ 2.89	$ 1.90	$ 2.56	$ 1.64

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $50.17 and $44.23 per Bbl and $3.09 and $2.79 per MMBtu, respectively, during the period from July 1, 2017 to July 31, 2017. At July 31, 2017, the NYMEX oil price and NYMEX natural gas price were $50.17 per Bbl and $2.79 per MMBtu, respectively.

Historically, and during the six months ended June 30, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $21.99 per Bbl and $18.16 per Bbl during the three months ended June 30, 2017 and 2016, respectively, and $23.09 per Bbl and $16.32 per Bbl during the six months ended June 30, 2017 and 2016, respectively.

Recent Events

Midland Basin acquisition. In July 2017, we completed an acquisition in the Midland Basin. As consideration for the acquisition, we paid approximately $600 million in cash, of which $60 million was held in escrow at June 30, 2017 with the remaining $540 million paid in July 2017. The acquisition is subject to customary post-closing adjustments.

Northern Delaware Basin acquisition. In April 2017, we closed on the remainder of the acquisition in the Northern Delaware Basin. As consideration for the entire acquisition, we paid approximately $159 million in cash and issued to the seller approximately 2.2 million shares of our common stock with an approximate value of $291 million.

Credit Facility amendment. In April 2017, we amended our credit facility to extend the maturity date to May 9, 2022. Additionally, we increased our borrowing base to $3.0 billion and decreased the commitments from our bank group to $2.0 billion.

Derivative Financial Instruments

Derivative financial instrument exposure. At June 30, 2017, the fair value of our financial derivatives was a net asset of $225 million. At June 30, 2017, all of our counterparties have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. At June 30, 2017, under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential "margin calls" on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Under the terms of our credit facility, certain events could occur that would cause the obligations under our credit facility to no longer be secured by our oil and natural gas properties. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. After June 30, 2017, we entered into the following oil price swaps and oil basis swaps to hedge additional amounts of our estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Price Swaps: (a)					
2017:					
Volume (Bbl)			1,253,000	1,354,000	2,607,000
Price per Bbl			$ 47.76	$ 47.73	$ 47.74
2018:					
Volume (Bbl)	1,059,000	869,000	747,000	669,000	3,344,000
Price per Bbl	$ 48.33	$ 48.26	$ 48.20	$ 48.15	$ 48.25
2019:					
Volume (Bbl)	1,002,000	940,000	885,000	845,000	3,672,000
Price per Bbl	$ 49.26	$ 49.24	$ 49.27	$ 49.26	$ 49.26
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)			915,000	1,380,000	2,295,000
Price per Bbl			$ (1.28)	$ (1.28)	$ (1.28)
2018:					
Volume (Bbl)	630,000	637,000	644,000	644,000	2,555,000
Price per Bbl	$ (1.11)	$ (1.11)	$ (1.11)	$ (1.11)	$ (1.11)
2019:					
Volume (Bbl)	810,000	819,000	828,000	828,000	3,285,000
Price per Bbl	$ (1.12)	$ (1.12)	$ (1.12)	$ (1.12)	$ (1.12)

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.

(b) The basis differential price is between Midland – WTI and Cushing – WTI.

Results of Operations

The following table sets forth summary information concerning our production and operating data for the three and six months ended June 30, 2017 and 2016. The actual historical data in this table excludes results from our acquisition from Reliance Energy, Inc. (the "Reliance Acquisition") for periods prior to October 2016. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of our acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	**2016**	**2017**	**2016**
Production and operating data:				
Average daily production volumes:				
Oil (Bbl)	113,220	89,418	113,409	89,214
Natural gas (Mcf)	428,769	334,440	417,762	318,632
Total (Boe)	184,682	145,158	183,036	142,319
Average prices per unit:				
Oil, without derivatives (Bbl)	$ 44.75	$ 41.68	$ 46.91	$ 35.80
Oil, with derivatives (Bbl) (a)	$ 51.60	$ 61.46	$ 51.86	$ 61.18
Natural gas, without derivatives (Mcf)	$ 2.71	$ 1.88	$ 2.85	$ 1.70
Natural gas, with derivatives (Mcf) (a)	$ 2.67	$ 2.13	$ 2.78	$ 1.95
Total, without derivatives (Boe)	$ 33.73	$ 30.00	$ 35.57	$ 26.25
Total, with derivatives (Boe) (a)	$ 37.84	$ 42.78	$ 38.48	$ 42.72
Operating costs and expenses per Boe:				
Oil and natural gas production	$ 5.91	$ 5.83	$ 5.64	$ 6.54
Production and ad valorem taxes	$ 2.62	$ 2.51	$ 2.77	$ 2.15
Depreciation, depletion and amortization	$ 16.69	$ 21.27	$ 17.02	$ 22.82
General and administrative	$ 3.70	$ 4.04	$ 3.54	$ 4.14

(a) Includes the effect of net cash receipts from (payments on) derivatives:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2017**	**2016**	**2017**	**2016**

Net cash receipts from (payments on) derivatives:				
Oil derivatives	$ 70	$ 160	$ 101	$ 412
Natural gas derivatives	(2)	8	(5)	15
Total	$ 68	$ 168	$ 96	$ 427

The presentation of average prices with derivatives is a result of including the net cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Three Months Ended June 30, 2017 Compared to Three Months Ended June 30, 2016

Oil and natural gas revenues. Revenue from oil and natural gas operations was $567 million for the three months ended June 30, 2017, an increase of $171 million (43 percent) from $396 million for 2016. This increase was primarily due to the increase in oil and natural gas production as well as the increase in realized oil and natural gas prices (excluding the effects of derivative activities). Specific factors affecting oil and natural gas revenues include the following:

- average daily oil production was 113,220 Bbl for the three months ended June 30, 2017, an increase of 23,802 Bbl (27 percent) from 89,418 Bbl for 2016;

- average realized oil price (excluding the effects of derivative activities) was $44.75 per Bbl during the three months ended June 30, 2017, an increase of 7 percent from $41.68 per Bbl during 2016. For the three months ended June 30, 2017, our crude oil price differential relative to NYMEX was $(3.57) per Bbl, or a realization of approximately 93 percent, as compared to a crude oil price differential relative to NYMEX of $(3.88) per Bbl, or a realization of approximately 91 percent, for 2016. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the three months ended June 30, 2017 and 2016, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.83 per Bbl and $0.17 per Bbl, respectively. Additionally, we incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. These fixed deductions were less per Boe during the three months ended June 30, 2017 as compared to 2016 primarily due to more production transported through pipelines;

- average daily natural gas production was 428,769 Mcf for the three months ended June 30, 2017, an increase of 94,329 Mcf (28 percent) from 334,440 Mcf for 2016; and

- average realized natural gas price (excluding the effects of derivative activities) was $2.71 per Mcf during the three months ended June 30, 2017, an increase of 44 percent from $1.88 per Mcf during 2016. For the three months ended June 30, 2017 and 2016, we realized approximately 86 percent and 84 percent, respectively, of the average NYMEX natural gas prices for the respective periods. The increase in our realized natural gas price (excluding the effects of derivatives) as a percentage of NYMEX during the three months ended June 30, 2017 as compared to 2016 was primarily due to an increase in the average Mont Belvieu price for a blended barrel of natural gas liquids. Historically, and during the three months ended June 30, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $21.99 per Bbl and $18.16 per Bbl during the three months ended June 30, 2017 and 2016, respectively.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 96	$ 5.66	$ 73	$ 5.47
Workover costs	4	0.25	4	0.36
Total oil and natural gas production expenses	$ 100	$ 5.91	$ 77	$ 5.83

Lease operating expenses were $96 million ($5.66 per Boe) for the three months ended June 30, 2017, which was an increase of $23 million from $73 million ($5.47 per Boe) for the three months ended June 30, 2016. The increase in lease operating expenses during the second quarter of 2017 as compared to 2016 was primarily due to increased production associated with our wells successfully drilled and completed in 2016 and 2017 and our acquisitions during the second half of 2016 and first half of 2017. The increase in lease operating expenses per Boe was primarily due to the increase in lease operating expenses noted above including higher expenses per Boe on properties associated with our recent acquisitions in the second half of 2016 and first half of 2017.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Production taxes	$ 40	$ 2.41	$ 30	$ 2.26
Ad valorem taxes	4	0.21	3	0.25
Total production and ad valorem taxes	$ 44	$ 2.62	$ 33	$ 2.51

Production taxes per unit of production were $2.41 per Boe during the three months ended June 30, 2017, an increase of 7 percent from $2.26 per Boe during 2016. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 12 percent. The increase in production taxes per unit of production was directly related to the increase in oil and natural gas sales, partially offset by a higher percentage of our total production originating in Texas, which has a lower tax rate than New Mexico. Production taxes fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
(in millions)	**2017**		**2016**	
Geological and geophysical	$	1	$	3
Exploratory dry hole costs		-		7
Leasehold abandonments		18		11
Other		1		-
Total exploration and abandonments	$	20	$	21

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

Our exploratory dry hole costs during the three months ended June 30, 2016 were primarily related to an uneconomic well in our Delaware Basin area that was attempting to establish commercial production through testing of multiple zones. We did not recognize any exploratory dry hole costs during the three months ended June 30, 2017.

For the three months ended June 30, 2017 and 2016, we recorded approximately $18 million and $11 million, respectively, of leasehold abandonments. For the three months ended June 30, 2017, our abandonments were primarily related to non-contiguous acreage expiring in our Southern Delaware Basin core area. For the three months ended June 30, 2016, our abandonments were primarily related to acreage in our Northern Delaware Basin core area where we identified (i) drilling locations which, based on multiple factors, are no longer likely to be drilled, (ii) acreage where we have no future development plans and (iii) expiring acreage.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
	2017		**2016**	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**

Depletion of proved oil and natural gas properties	$	274	$	16.34	$	276	$	20.84
Depreciation of other property and equipment		6		0.33		4		0.40
Amortization of intangible assets - operating rights		1		0.02		1		0.03
Total depletion, depreciation and amortization	$	281	$	16.69	$	281	$	21.27
Oil price used to estimate proved oil reserves at period end	$	45.42			$	39.63		
Natural gas price used to estimate proved natural gas reserves at period end	$	3.01			$	2.24		

Depletion of proved oil and natural gas properties was $274 million ($16.34 per Boe) for the three months ended June 30, 2017 and $276 million ($20.84 per Boe) for 2016. Depletion expense remained relatively flat period over period due to offsetting factors of increased production and lower expenses per Boe. The decrease in depletion expense per Boe period over period was primarily due to (i) an overall increase in proved reserves period over period primarily due to our successful exploratory drilling program, the Reliance Acquisition, the Northern Delaware Basin acquisition, reductions in future estimated lease operating expenses and an increase in commodity prices period over period, partially offset by decreased proved reserves caused by reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of their initial recording and (ii) lower drilling and completion costs per Boe of proved developed reserves added.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We estimate undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At June 30, 2017, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $45.26 per barrel of oil to a 2024 price of $53.68 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.16 per Mcf of natural gas decreasing to a 2020 price of $2.83 per Mcf of natural gas partially recovering to a 2024 price of $3.03 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

We estimate fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value. We did not recognize an impairment charge during the three months ended June 30, 2017 or 2016.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets.

Based on economic factors at June 30, 2017, we determined that undiscounted future cash flows attributable to our North Basin Bone Spring ("NBBS") field located in the northern Delaware Basin with a net book value of approximately $1.2 billion indicated that its carrying amount was expected to be recovered; however, it may be at risk for impairment if management's estimates of future cash flows decline, including as a result of further declines in projected commodity prices (and the resulting impact of future cash flows). We estimate that if the future oil and natural gas prices used in this analysis, and noted above, would have been approximately 10 percent lower at June 30, 2017 with no other changes in capital costs, operating costs, price differentials, or reserve performance curves, we could have recognized a non-cash impairment in that period of approximately $365 million related to our NBBS field. Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices. However, we did not estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge. As a result, we are unable to predict with certainty whether or not a decline in commodity prices alone will cause us to recognize an impairment charge in a particular field or the magnitude of any such impairment charge. We additionally note that there may be changes to both drilling and completion designs that affect the volume curves, capital costs estimates, and the amount of proved undeveloped locations that can be recorded, each of which will affect management’s estimates of future cash flows.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 50	$ 3.06	$ 45	$ 3.37
Less: Operating fee reimbursements	(4)	(0.25)	(4)	(0.27)
Non-cash stock-based compensation	14	0.89	12	0.94
Total general and administrative expenses	$ 60	$ 3.70	$ 53	$ 4.04

General and administrative expenses were approximately $60 million ($3.70 per Boe) for the three months ended June 30, 2017, an increase of $7 million (13 percent) from $53 million ($4.04 per Boe) for 2016. The increase in cash general and administrative expenses was primarily a result of increased compensation expense. The increase in non-cash stock-based compensation was primarily due to an increase in forfeiture estimates during 2016. The decrease in total general and administrative expenses per Boe was primarily due to increased production period over period, partially offset by the increase in general and administrative costs noted above.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of approximately $4 million for each of the three months ended June 30, 2017 and 2016.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
(in millions)		**2017**		**2016**
Gain (loss) on derivatives:				
Oil derivatives	$	199	$	(281)
Natural gas derivatives		10		(17)
Total	$	209	$	(298)

The following table represents our net cash receipts from (payments on) derivatives for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,			
(in millions)		**2017**		**2016**
Net cash receipts from (payments on) derivatives:				
Oil derivatives	$	70	$	160
Natural gas derivatives		(2)		8
Total	$	68	$	168

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent the future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 6 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Interest expense. Interest expense was $39 million for the three months ended June 30, 2017 as compared to $55 million during 2016. The decrease was primarily due to (i) approximately $11 million for the early redemption of our $600 million 7.0% unsecured senior notes in September 2016 and (ii) approximately $3 million, net, for the satisfaction and discharge of our $600 million 6.5% unsecured senior notes in December 2016 and our issuance of $600 million 4.375% unsecured senior notes in December 2016.

Loss on extinguishment of debt. In April 2017, we amended our credit facility. We recorded a loss on extinguishment of debt of approximately $1 million for the three months ended June 30, 2017, representing the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the credit facility syndicate.

Income tax provisions. We recorded income tax expense of $93 million, which includes discrete income tax expense of approximately $2 million related to excess tax deficiencies on stock-based awards, which are recorded in the income tax provision pursuant to Accounting Standards Update ("ASU") No. 2016-09, which was adopted on January 1, 2017, and an income tax benefit of $158 million for the three months ended June 30, 2017 and 2016, respectively. The change in our income tax provision was primarily due to income before income taxes during the three months ended June 30, 2017, as compared to a loss before income taxes during 2016. The effective income tax rates for the three months ended June 30, 2017 and 2016 were 37.8 percent and 37.3 percent, respectively.

Six Months Ended June 30, 2017 Compared to Six Months Ended June 30, 2016

Oil and natural gas revenues. Revenue from oil and natural gas operations was $1,179 million for the six months ended June 30, 2017, an increase of $499 million (73 percent) from $680 million for 2016. This increase was primarily due to the increase in oil and natural gas production as well as the increase in realized oil and natural gas prices (excluding the effects of derivative activities). Specific factors affecting oil and natural gas revenues include the following:

- average daily oil production was 113,409 Bbl for the six months ended June 30, 2017, an increase of 24,195 Bbl (27 percent) from 89,214 Bbl for 2016;

- average realized oil price (excluding the effects of derivative activities) was $46.91 per Bbl during the six months ended June 30, 2017, an increase of 31 percent from $35.80 per Bbl during 2016. For the six months ended June 30, 2017, our crude oil price differential relative to NYMEX was $(3.21) per Bbl, or a realization of approximately 94 percent, as compared to a crude oil price differential relative to NYMEX of $(3.85) per Bbl, or a realization of approximately 90 percent, for 2016. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil directly impacts our realized oil price. For the six months ended June 30, 2017 and 2016, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.09 per Bbl and $0.01 per Bbl, respectively. Additionally, we incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. These fixed deductions were less per Boe during the six months ended June 30, 2017 as compared to 2016 primarily due to (i) more production transported through pipelines and (ii) successful renegotiation of fixed deductions for existing production transported through pipelines;

- average daily natural gas production was 417,762 Mcf for the six months ended June 30, 2017, an increase of 99,130 Mcf (31 percent) from 318,632 Mcf for 2016; and

- average realized natural gas price (excluding the effects of derivative activities) was $2.85 per Mcf during the six months ended June 30, 2017, an increase of 68 percent from $1.70 per Mcf during 2016. For the six months ended June 30, 2017 and 2016, we realized approximately 91 percent and 80 percent, respectively, of the average NYMEX natural gas prices for the respective periods. The increase in our realized natural gas price (excluding the effects of derivatives) as a percentage of NYMEX during the six months ended June 30, 2017 as compared to 2016 was primarily due to an increase in the average Mont Belvieu price for a blended barrel of natural gas liquids. Historically, and during the six months ended June 30, 2017, we derived a significant portion of our total natural gas revenues from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. The average Mont Belvieu price for a blended barrel of natural gas liquids was $23.09 per Bbl and $16.32 per Bbl during the six months ended June 30, 2017 and 2016, respectively.

During December 2015, a third-party natural gas processing plant located in the northern Delaware Basin became inoperable following an explosion. We estimate that this event negatively impacted production for the six months ended June 30, 2016 by approximately 2.4 MBoepd. The plant became fully operational during April 2016.

Oil and natural gas production expenses. The following table provides the components of our oil and natural gas production expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,							
	2017				2016			
(in millions, except per unit amounts)		**Amount**		**Per Boe**		**Amount**		**Per Boe**
Lease operating expenses	$	178	$	5.36	$	159	$	6.15
Workover costs		9		0.28		10		0.39
Total oil and natural gas production expenses	$	187	$	5.64	$	169	$	6.54

Lease operating expenses were $178 million ($5.36 per Boe) for the six months ended June 30, 2017, which was an increase of $19 million from $159 million ($6.15 per Boe) for the six months ended June 30, 2016. The increase in lease operating expenses during the first half of 2017 as compared to 2016 was primarily due to increased production associated with our wells successfully drilled and completed in 2016 and 2017, partially offset by (i) implementation of operational cost efficiencies, including improved infrastructure around salt water disposals and (ii) an overall decrease in the cost of goods and services. The decrease in lease operating expenses per Boe was primarily due to implementation of operational costs efficiencies partially offset by higher expenses per Boe on properties associated with our recent acquisitions in the second half of 2016 and first half of 2017.

Production and ad valorem taxes. The following table provides the components of our production and ad valorem tax expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,							
	2017				2016			
(in millions, except per unit amounts)		**Amount**		**Per Boe**		**Amount**		**Per Boe**
Production taxes	$	84	$	2.53	$	47	$	1.81
Ad valorem taxes		8		0.24		9		0.34
Total production and ad valorem taxes	$	92	$	2.77	$	56	$	2.15

Production taxes per unit of production were $2.53 per Boe during the six months ended June 30, 2017, an increase of 40 percent from $1.81 per Boe during 2016. Over the same period, our revenue per Boe (excluding the effects of derivatives) increased 36 percent. The increase in production taxes per unit of production was directly related to the increase in oil and natural gas sales. Additionally, tax credits of approximately $4 million were received during the first quarter of 2016 related to certain wells in Texas qualifying for reduced severance tax rates. Production taxes fluctuate with the market value of our production sold, while ad valorem taxes are generally based on the valuation of our oil and natural gas properties at the beginning of the year, which vary across the different areas in which we operate.

Exploration and abandonments expense. The following table provides the components of our exploration and abandonments expense for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
(in millions)	**2017**	**2016**
Geological and geophysical	$ 7	$ 4
Exploratory dry hole costs	-	7
Leasehold abandonments	24	32
Other	4	1
Total exploration and abandonments	$ 35	$ 44

Our geological and geophysical expense for the periods presented above primarily consists of the costs of acquiring and processing geophysical data and core analysis.

Our exploratory dry hole costs during the six months ended June 30, 2016 were primarily related to an uneconomic well in our Delaware Basin area that was attempting to establish commercial production through testing of multiple zones. We did not recognize any exploratory dry hole costs during the six months ended June 30, 2017.

For the six months ended June 30, 2017 and 2016, we recorded approximately $24 million and $32 million, respectively, of leasehold abandonments. For the six months ended June 30, 2017, our abandonments were primarily related to (i) non-contiguous acreage expiring in our Southern Delaware Basin core area and (ii) acreage in our Northern Delaware Basin and Midland Basin core areas in locations where we have no future plans to drill. For the six months ended June 30, 2016, our abandonments were primarily related to (i) drilling locations in our Delaware Basin and New Mexico Shelf areas which, based on multiple factors, are no longer likely to be drilled, (ii) acreage in our Delaware Basin and New Mexico Shelf areas where we have no future development plans and (iii) expiring acreage.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the six months ended June 30, 2017 and 2016:

Six Months Ended June 30,

		2017				2016		
(in millions, except per unit amounts)		**Amount**		**Per Boe**		**Amount**		**Per Boe**
Depletion of proved oil and natural gas properties	$	551	$	16.65	$	580	$	22.39
Depreciation of other property and equipment		12		0.35		10		0.40
Amortization of intangible assets - operating rights		1		0.02		1		0.03
Total depletion, depreciation and amortization	$	564	$	17.02	$	591	$	22.82

Depletion of proved oil and natural gas properties was $551 million ($16.65 per Boe) for the six months ended June 30, 2017, a decrease of $29 million (5 percent) from $580 million ($22.39 per Boe) for 2016. The decrease in depletion expense was primarily due to a lower depletion rate per Boe period over period partially offset by an increase in production. The decrease in depletion expense per Boe period over period was primarily due to (i) a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016, (ii) an overall increase in proved reserves period over period primarily caused by our successful exploratory drilling program, the Reliance Acquisition, the Northern Delaware Basin acquisition, reductions in future estimated lease operating expenses and higher commodity prices period over period, partially offset by decreased proved reserves caused by reclassification of proved undeveloped reserves to unproved reserves because they are no longer expected to be developed within five years of their initial recording and (iii) lower drilling and completion costs per Boe of proved developed reserves added.

Impairments of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties and their integrated assets, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. We review our oil and natural gas properties by depletion base. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. If the estimated undiscounted future net cash flows are less than the carrying amount of our assets, we recognize an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset.

We estimate undiscounted future net cash flows of our long-lived assets and their integrated assets using management's assumptions and expectations of (i) commodity prices, which are based on the NYMEX strip, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, and (vii) prevailing market rates of income and expenses from integrated assets. At June 30, 2017, our estimates of commodity prices for purposes of determining undiscounted future cash flows, which are based on the NYMEX strip, ranged from a 2017 price of $45.26 per barrel of oil to a 2024 price of $53.68 per barrel of oil. Similarly, natural gas prices ranged from a 2017 price of $3.16 per Mcf of natural gas decreasing to a 2020 price of $2.83 per Mcf of natural gas partially recovering to a 2024 price of $3.03 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2024.

We estimate fair values of our long-lived assets and their integrated assets using a discounted future cash flow model. Fair value assumptions associated with the calculation of discounted future net cash flows include (i) market estimates of commodity prices, (ii) pricing adjustments for differentials, (iii) production costs, (iv) capital expenditures, (v) production volumes, (vi) estimated proved reserves and risk-adjusted probable and possible reserves, (vii) prevailing market rates of income and expenses from integrated assets and (viii) discount rate. The expected future net cash flows were discounted using an annual rate of 10 percent to determine fair value.

During the three months ended March 31, 2016, NYMEX strip prices declined as compared to December 31, 2015, and as a result the carrying amount of our Yeso field in our New Mexico Shelf core area exceeded the expected undiscounted future net cash flows resulting in a non-cash charge against earnings of approximately $1.5 billion. The Yeso field, as compared to our other fields not previously impaired, had significant proved reserves upon acquisition, which required a higher valuation than a field more exploratory in nature that has a higher risk factor adjustment in the fair value estimate. Our estimates of commodity prices for purposes of determining the estimated fair value at March 31, 2016 ranged from a 2016 price of $41.26 per barrel of oil and $2.26 per Mcf of natural gas to a 2023 price of $66.33 per barrel of oil and $3.56 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2023. We did not recognize an impairment charge during the six months ended June 30, 2017.

It is reasonably possible that the estimate of undiscounted future net cash flows of our long-lived assets may change in the future resulting in the need to impair carrying values. The primary factors that may affect estimates of future net cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve volume adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves, (iv) results of future drilling activities and (v) prevailing market rates of income and expenses from integrated assets.

Based on economic factors at June 30, 2017, we determined that undiscounted future cash flows attributable to our NBBS field located in the northern Delaware Basin with a net book value of approximately $1.2 billion indicated that its carrying amount was expected to be recovered; however, it may be at risk for impairment if management's estimates of future cash flows decline, including as a result of further declines in projected commodity prices (and the resulting impact of future cash flows). We estimate that if the future oil and natural gas prices used in this analysis, and noted above, would have been approximately 10 percent lower at June 30, 2017 with no other changes in capital costs, operating costs, price differentials, or reserve performance curves, we could have recognized a non-cash impairment in that period of approximately $365 million related to our NBBS field. Other assumptions such as operating costs, well and reservoir performance, severance and ad valorem taxes, and operating and development plans would likely change given a change in oil and natural gas prices. However, we did not estimate the correlation between these assumptions and any estimated commodity price change, and these and other assumptions may worsen or partially mitigate some of the effects of a reduction in commodity prices, including the ultimate impact and amount of any potential impairment charge. As a result, we are unable to predict with certainty whether or not a decline in commodity prices alone will cause us to recognize an impairment charge in a particular field or the magnitude of any such impairment charge. We additionally note that there may be changes to both drilling and completion designs that affect the volume curves, capital costs estimates, and the amount of proved undeveloped locations that can be recorded, each of which will affect management's estimates of future cash flows.

General and administrative expenses. The following table provides components of our general and administrative expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,			
	2017		2016	
(in millions, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 98	$ 2.99	$ 87	$ 3.35
Less: Operating fee reimbursements	(8)	(0.24)	(8)	(0.31)
Non-cash stock-based compensation	26	0.79	28	1.10
Total general and administrative expenses	$ 116	$ 3.54	$ 107	$ 4.14

General and administrative expenses were approximately $116 million ($3.54 per Boe) for the six months ended June 30, 2017, an increase of $9 million (8 percent) from $107 million ($4.14 per Boe) for 2016. The increase in cash general and administrative expenses was primarily a result of increased compensation expense. The decrease in non-cash stock-based compensation was partially due to recording forfeitures as they occur rather than recording forfeiture estimates per the adoption of ASU No. 2016-09 on January 1, 2017. The decrease in total general and administrative expenses per Boe was primarily due to increased production period over period, partially offset by the increase in general and administrative costs noted above.

We receive fees for the operation of jointly-owned oil and natural gas properties during the drilling and production phases and record such reimbursements as reductions of general and administrative expenses in the consolidated statements of operations. We earned reimbursements of approximately $8 million for each of the six months ended June 30, 2017 and 2016.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the six months ended June 30, 2017 and 2016:

(in millions)	Six Months Ended June 30, 2017		2016	
Gain (loss) on derivatives:				
Oil derivatives	$	465	$	(209)
Natural gas derivatives		30		(8)
Total	$	495	$	(217)

The following table represents our net cash receipts from (payments on) derivatives for the six months ended June 30, 2017 and 2016:

(in millions)	Six Months Ended June 30, 2017		2016	
Net cash receipts from (payments on) derivatives:				
Oil derivatives	$	101	$	412
Natural gas derivatives		(5)		15
Total	$	96	$	427

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent the future commodity price outlook increases between measurement periods, we will have mark-to-market losses. See Note 6 of the Condensed Notes to Consolidated Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding significant judgments made in classifying financial instruments in the fair value hierarchy.

Gain on disposition of assets, net. In February 2017, we closed on our previously announced divestiture of our ownership interest in ACC. After adjustments for debt and working capital, we received cash proceeds from the sale of approximately $803 million. After direct transaction costs, we recorded a pre-tax gain on disposition of assets of approximately $655 million. Our net investment in ACC at the time of closing was approximately $129 million.

In February 2016, we sold certain assets in the northern Delaware Basin for proceeds of approximately $292 million and recognized a pre-tax gain of approximately $110 million.

Interest expense. Interest expense was $79 million for the six months ended June 30, 2017 as compared to $109 million during 2016. The decrease was primarily due to (i) approximately $21 million for the early redemption of our $600 million 7.0% unsecured senior notes in September 2016 and (ii) approximately $5 million, net, for the satisfaction and discharge of our $600 million 6.5% unsecured senior notes in December 2016 and our issuance of $600 million 4.375% unsecured senior notes in December 2016.

Loss on extinguishment of debt. In April 2017, we amended our credit facility. We recorded a loss on extinguishment of debt of approximately $1 million for the six months ended June 30, 2017, representing the proportional amount of unamortized deferred loan costs associated with banks that are no longer in the credit facility syndicate.

Income tax provisions. We recorded income tax expense of $464 million, which includes a discrete income tax benefit of approximately $6 million related to excess tax benefits on stock-based awards, which are recorded in the income tax provision pursuant to ASU No. 2016-09, which was adopted on January 1, 2017, and an income tax benefit of $752 million for the six months ended June 30, 2017 and 2016, respectively. The change in our income tax provision was primarily due to income before income taxes during the six months ended June 30, 2017, as compared to a loss before income taxes during

2016. The effective income tax rates for the six months ended June 30, 2017 and 2016 were 36.6 percent and 36.9 percent, respectively.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, midstream joint venture and other capital commitments, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility, proceeds from the disposition of assets or alternative financing sources, as discussed in "— Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions, during the six months ended June 30, 2017 and 2016 totaled $775 million and $525 million, respectively. The increase was primarily due to our increased drilling and completion activity level during the first half of 2017 as compared to 2016. Our intent is to manage our capital spending to be within our cash flow, excluding unbudgeted acquisitions. The primary reason for the differences in costs incurred and cash flow expenditures was our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition and timing of payments. Total 2017 expenditures were primarily funded in part from (i) cash flows from operations, (ii) our issuance of approximately 2.2 million shares of common stock related to our Northern Delaware Basin acquisition and to a lesser extent (iii) proceeds from our February 2017 divestiture of ACC.

2017 capital budget. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling and multi-well pad development. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. However, if we were to outspend our cash flows, we believe we could use our (i) cash on hand, (ii) credit facility and (iii) other financing sources to fund any cash flow deficits. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments, commodity prices, leverage metrics and industry conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
(in millions)	**2017**	**2016**

Property acquisition costs:				
Proved	$	139	$	256
Unproved		393		158
Total property acquisition costs (a)	$	532	$	414

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of $18 million and $23 million for the six months ended June 30, 2017 and 2016, respectively. For the six months ended June 30, 2017, our unbudgeted acquisitions are primarily comprised of approximately $451 million of property acquisition costs related to our Northern Delaware Basin acquisition. For the six months ended June 30, 2016, our unbudgeted acquisitions are primarily comprised of approximately $374 million of property acquisition costs related to our Southern Delaware Basin acquisition.

Contractual obligations. Our contractual obligations include long-term debt, cash interest expense on debt, derivative liabilities, asset retirement obligations, employment agreements with officers, purchase obligations, operating lease obligations and other obligations. Since December 31, 2016, the changes in our contractual obligations are not material, other than our derivative liability position, which decreased by $178 million. See Note 8 of the Condensed Notes to Consolidated

Financial Statements included in “Item 1. Consolidated Financial Statements (Unaudited)” for additional information regarding our long-term debt and “Item 3. Quantitative and Qualitative Disclosures About Market Risk” for information regarding the interest on our long-term debt and information on changes in the fair value of our open derivative obligations during the six months ended June 30, 2017.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from (i) operating activities, (ii) borrowings under our credit facility, (iii) proceeds from bond and equity offerings and (iv) asset dispositions. In February 2017, we announced our updated 2017 capital budget, excluding acquisitions, of approximately $1.8 billion with expected capital spending to range between $1.6 billion and $1.8 billion. Approximately 90 percent of capital will be directed to drilling and completion activity. Our 2017 capital program is expected to continue focusing on extended length lateral drilling and multi-well pad development. Our 2017 capital budget, based on our current expectations of commodity prices and costs, is expected to be within our cash flows. However, if we were to outspend our cash flows, we believe we could use our (i) cash on hand, (ii) credit facility and (iii) other financing sources to fund any cash flow deficits. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments, commodity prices, leverage metrics and industry conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

The following table summarizes our changes in cash and cash equivalents for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,	
(in millions)	**2017**	**2016**
Net cash provided by operating activities	$ 805	$ 676
Net cash used in investing activities	(168)	(412)
Net cash used in financing activities	(28)	(12)
Net increase in cash and cash equivalents	$ 609	$ 252

Cash flow from operating activities. The increase in operating cash flows during the six months ended June 30, 2017 as compared to the same period in 2016 was primarily due to (i) an increase in oil and natural gas revenues of approximately $499 million, (ii) a decrease in cash interest expense of approximately $30 million and (iii) approximately $8 million of positive variances in operating assets and liabilities, partially offset by (i) approximately

$96 million from settlements on derivatives during the six months ended June 30, 2017, as compared to $427 million from settlements on derivatives during the comparable period in 2016, (ii) approximately $36 million increase in production tax expense, (iii) a decrease in operating cash flow of approximately $22 million due to cash tax expense of approximately $10 million for the six months ended June 30, 2017, as compared to a cash tax benefit of approximately $12 million during the comparable period in 2016 and (iv) approximately $18 million increase in production expense.

Our net cash provided by operating activities included a reduction of approximately $18 million and $26 million for the six months ended June 30, 2017 and 2016, respectively, associated with changes in working capital items. Changes in working capital items adjust for the timing of receipts and payments of actual cash.

Cash flow from investing activities. During the six months ended June 30, 2017 and 2016, we invested approximately $863 million and $651 million, respectively, for capital expenditures on oil and natural gas properties. Additionally, we received approximately $803 million related to proceeds from the disposition of assets during the six months ended June 30, 2017, as compared to $294 million during the comparable period of 2016.

Cash flow from financing activities. Net cash used in financing activities was approximately $28 million and $12 million for the six months ended June 30, 2017 and 2016, respectively. In April 2017, we amended our credit facility to decrease our unused lender commitments and increase our borrowing base. At June 30, 2017, we had unused commitments on our credit facility of $2.0 billion and a borrowing base of $3.0 billion.

Advances on our amended and restated credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank (“JPM Prime Rate”) (4.25 percent at June 30, 2017) or (ii) the London Interbank Offered Rate (“LIBOR”). The credit facility’s interest rates vary, with interest margins ranging from 125 to 225 basis points (LIBOR Rate Loans) and 25 to 125 basis points (Alternate Base Rate Loans) per annum depending on the utilization of the borrowing base. We pay commitment fees on the unused portion of the available commitment ranging from 30.0 to 37.5 basis points per annum, depending on utilization of the borrowing base. Subject to certain restrictions, with respect to our public debt ratings, the collateral securing the facility may be released.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Historically, we have demonstrated our use of the capital markets by issuing common stock and senior unsecured debt. There are no assurances that we can access the capital markets to obtain additional funding, if needed, and at cost and terms that are favorable to us. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in energy companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of liquidity are cash on hand and available borrowing capacity under our credit facility. At June 30, 2017, we had approximately $662 million of cash on hand. In July 2017, we paid approximately $540 million in cash as consideration for our Midland Basin acquisition in addition to the $60 million of cash held in escrow at June 30, 2017.

During April 2017, we amended our credit facility to extend the maturity date to May 9, 2022. Additionally, we increased our borrowing base to $3.0 billion and decreased our commitments from bank groups to $2.0 billion. Upon a subsequent redetermination, there is no assurance that our borrowing base will not be reduced, which could affect our liquidity.

We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Debt ratings. We receive debt credit ratings from S&P Global Ratings ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P and Moody's consider many factors in determining our ratings including: the industry in which we operate, production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

A downgrade in our credit ratings could negatively impact our costs of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

As of the filing of this Quarterly Report, no changes in our credit ratings have occurred since June 30, 2017; however, we cannot be assured that our credit ratings will not be downgraded in the future.

Book capitalization and current ratio. Our net book capitalization at June 30, 2017 was $10.7 billion, consisting of $0.7 billion of cash and cash equivalents, debt of $2.7 billion and stockholders' equity of $8.7 billion. Our net book capitalization at December 31, 2016 was $10.2 billion, consisting of $0.1 billion of cash and cash equivalents, debt of $2.7 billion and stockholders' equity of $7.6 billion. Our ratio of net debt to net book capitalization was 19 percent and 26 percent at June 30, 2017 and December 31, 2016, respectively. Our ratio of current assets to current liabilities was 1.70 to 1.0 at June 30, 2017 as compared to 0.73 to 1.0 at December 31, 2016. Both our ratio of net debt to net book capitalization and our ratio of current assets to current liabilities were impacted subsequent to June 30, 2017 by the Midland Basin acquisition in July 2017.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the six months ended June 30, 2017, we received an average of $46.91 per Bbl of oil and $2.85 per Mcf of natural gas before consideration of commodity derivative contracts compared to $35.80 per Bbl of oil and $1.70 per Mcf of natural gas in the six months ended June 30, 2016. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business.

Critical Accounting Policies, Practices and Estimates

Our historical consolidated financial statements and related condensed notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of business combinations, valuation of nonmonetary exchanges, valuation of financial derivative instruments, valuation of stock-based compensation and income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the six months ended June 30, 2017. See our disclosure of critical accounting policies in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 8. Financial Statements and Supplementary Data" of our Annual Report on Form 10-K for the year ended December 31, 2016, filed with the United States Securities and Exchange Commission (the "SEC") on February 22, 2017.

New accounting pronouncements issued but not yet adopted. In February 2016, the Financial Accounting Standards Board (the "FASB") issued ASU No. 2016-02, "Leases (Topic 842)," which supersedes current lease guidance. The new lease standard requires all leases with a term greater than one year to be recognized on the balance sheet while maintaining substantially similar classifications for finance and operating leases. Lease expense recognition on the income statement will be effectively unchanged. This guidance is effective for reporting periods beginning after December 15, 2018 and early adoption is permitted. We are evaluating the impact that this new guidance will have on our consolidated financial statements.

In January 2017, the FASB issued ASU No. 2017-01, "Business Combinations (Topic 805): Clarifying the Definition of a Business," with the objective of adding guidance to assist in evaluating whether transactions should be accounted for as asset acquisitions or as business combinations. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the acquired assets is concentrated in a single asset or a group of similar assets, the set is not a business. If the screen is not met, to be considered a business, the set must include an input and a substantive process that together significantly contribute to the ability to create output. This new guidance is effective for annual periods beginning after December

15, 2017, and early adoption is allowed. We are evaluating the impact this new guidance will have on our consolidated financial statements. The new guidance could result in more acquisitions of oil and natural gas properties being accounted for as asset acquisitions instead of business combinations.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Annual Report on Form 10-K for the year ended December 31, 2016.

We are exposed to a variety of market risks, including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at June 30, 2017, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries, and to a lesser extent, our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. Under the terms of our credit facility, certain events could occur that would cause the obligations under our credit facility to no longer be secured by our oil and natural gas properties.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set-off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 7 of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on net income. The following table sets forth the hypothetical impact on the fair value of the commodity price risk management arrangements from an average increase and decrease in the commodity price of $5.00 per Bbl of oil and $0.50 per MMBtu of natural gas from the commodity prices at June 30, 2017:

(in millions)	**Increase of $5.00 per Bbl and $0.50 per MMBtu**	**Decrease of $5.00 per Bbl and $0.50 per MMBtu**
Gain (loss):		
Oil derivatives	$ (262)	$ 262
Natural gas derivatives	(38)	38
Total	$ (300)	$ 300

At June 30, 2017, we had (i) oil price swaps that settle on a monthly basis covering future oil production from July 1, 2017 through December 31, 2019 and (ii) oil basis swaps covering our Midland to Cushing basis differential from July 1, 2017 to December 31, 2019. The average NYMEX oil price for the six months ended June 30, 2017 was $50.12 per Bbl. At July 31, 2017, the NYMEX oil price was $50.17 per Bbl.

At June 30, 2017, we had natural gas price swaps that settle on a monthly basis covering future natural gas production from July 1, 2017 to December 31, 2019. The average NYMEX natural gas price for the six months ended June 30, 2017 was $3.12 per MMBtu. At July 31, 2017, the NYMEX natural gas price was $2.79 per MMBtu.

A decrease in the average forward NYMEX oil and natural gas prices below those at June 30, 2017 would increase the fair value asset of our commodity derivative contracts from their recorded balance at June 30, 2017. Changes in the recorded fair value of our commodity derivative contracts are marked to market through earnings as gains or losses. The potential increase in our fair value asset would be recorded in earnings as a gain. However, an increase in the average forward NYMEX oil and natural gas prices above those at June 30, 2017 would decrease the fair value asset of our commodity derivative contracts from their recorded balance at June 30, 2017. The potential decrease in our fair value asset would be recorded in earnings as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method for our derivative instruments during the six months ended June 30, 2017. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the six months ended June 30, 2017:

(in millions)		**Commodity Derivative Instruments Net Assets (Liabilities) (a)**
Fair value of contracts outstanding at December 31, 2016	$	(174)
Changes in fair values (b)		495
Contract maturities		(96)
Fair value of contracts outstanding at June 30, 2017	$	225

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) At inception, new derivative contracts entered into by us have no intrinsic value.

See Note 7 of the Condensed Notes to Consolidated Financial Statements included in "Item 1. Consolidated Financial Statements (Unaudited)" for additional information regarding our derivative instruments.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we may, in the future, enter into interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our borrowing base.

We had no indebtedness outstanding under our credit facility at June 30, 2017.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) as of the end of the period covered by this Quarterly Report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at June 30, 2017 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 1A. Risk Factors

In addition to the information set forth in this Quarterly Report, you should carefully consider the risks discussed in our Annual Report on Form 10-K for the year ended December 31, 2016, under the headings "Item 1. Business — Competition," "— Marketing Arrangements" and "— Applicable Laws and Regulations," "Item 1A. Risk Factors," "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" and the risks discussed in our Quarterly Report on Form 10-Q for the three months ended March 31, 2017, under the heading "Item 1A. Risk Factors," which risks could materially affect our business, financial condition or future results. There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2016 and in our Quarterly Report on Form 10-Q for the three months ended March 31, 2017. The risks described in our Annual Report on Form 10-K for the year ended December 31, 2016 and in our Quarterly Report on Form 10-Q for the three months ended March 31, 2017 are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results.

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

Period	Total number of shares withheld (a)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
April 1, 2017 - April 30, 2017	279	$ 127.56	-	
May 1, 2017 - May 31, 2017	975	$ 130.27	-	
June 1, 2017 - June 30, 2017	11,763	$ 115.94	-	

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

Item 6. Exhibits

Exhibit Number		Exhibit
3.1		Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2		Third Amended and Restated Bylaws of Concho Resources Inc., as amended March 27, 2017 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on March 28, 2017, and incorporated herein by reference).
4.1		Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).
10.1	(a)	Second Amendment to Second Amended and Restated Credit Agreement, dated as of April 12, 2017, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent.
10.2	**	Retirement Agreement, dated May 17, 2017, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 19, 2017, and incorporated herein by reference).
31.1	(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	(a)	XBRL Instance Document.
101.SCH	(a)	XBRL Schema Document.

101.CAL	(a)	XBRL Calculation Linkbase Document.
101.DEF	(a)	XBRL Definition Linkbase Document.
101.LAB	(a)	XBRL Labels Linkbase Document.
101.PRE	(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

** Management compensatory plan or agreement

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.

CONCHO RESOURCES INC.

Date:	August 3, 2017	By	/s/ Timothy A. Leach
			Timothy A. Leach Director, Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)
		By	/s/ Jack F. Harper
			Jack F. Harper President and Chief Financial Officer (Principal Financial Officer)
		By	/s/ Brenda R. Schroer
			Brenda R. Schroer Senior Vice President, Chief Accounting Officer and Treasurer (Principal Accounting Officer)

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(b) Furnished herewith.

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