CONCHO RESOURCES INC
Form 10-Q
August 03, 2016

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, 2016

or

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

For the transition period from ____________________ to ____________________

Commission file number: 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Number of shares of the registrant's common stock outstanding at August 1, 2016: 131,799,601 shares

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this Quarterly Report on Form 10-Q (this “Quarterly 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,” “foresee,” “plan,” “goal” or other words that convey the uncertainty of future events 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 Quarterly 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” in our Quarterly Reports and in our Annual Report on Form 10-K for the year ended December 31, 2015, as well as those factors summarized below:

- declines in the prices we receive for our oil and natural gas, or sustained depressed prices we receive, for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling and operating risks;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- 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;
- the impact of potential changes in our credit ratings;
- 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 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;
- 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 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 thousands, except share and per share amounts)		June 30, 2016		December 31, 2015
Assets				
Current assets:				
Cash and cash equivalents	$	481,230	$	228,550
Accounts receivable, net of allowance for doubtful accounts:				
Oil and natural gas		200,234		203,972
Joint operations and other		163,354		190,608
Derivative instruments		230,779		652,498
Prepaid costs and other		36,393		38,922
Total current assets		1,111,990		1,314,550
Property and equipment:				
Oil and natural gas properties, successful efforts method		16,490,330		15,846,307
Accumulated depletion and depreciation		(7,107,852)		(5,047,810)
Total oil and natural gas properties, net		9,382,478		10,798,497
Other property and equipment, net		183,966		178,450
Total property and equipment, net		9,566,444		10,976,947
Deferred loan costs, net		13,247		15,585
Intangible asset - operating rights, net		24,963		25,693
Inventory		16,293		19,118
Noncurrent derivative instruments		-		167,038
Other assets		168,680		122,945
Total assets	$	10,901,617	$	12,641,876
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable - trade	$	20,172	$	13,200
Revenue payable		109,204		169,787
Accrued and prepaid drilling costs		279,362		228,523
Derivative instruments		412		-
Other current liabilities		166,440		184,910
Total current liabilities		575,590		596,420
Long-term debt		3,333,532		3,332,188
Deferred income taxes		890,324		1,630,373
Noncurrent derivative instruments		54,362		-
Asset retirement obligations and other long-term liabilities		144,103		140,344
Commitments and contingencies (Note 10)				
Stockholders' equity:				
Common stock, $0.001 par value; 300,000,000 authorized; 132,240,074 and 129,444,042 shares issued at June 30, 2016 and December 31, 2015, respectively		132		129
Additional paid-in capital		4,887,420		4,628,390
Retained earnings		1,059,476		2,345,641
Treasury stock, at cost; 427,844 and 306,061 shares at June 30, 2016 and				

December 31, 2015, respectively		(43,322)		(31,609)
Total stockholders' equity		5,903,706		6,942,551
Total liabilities and stockholders' equity	$	10,901,617	$	12,641,876

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

Concho Resources Inc.
Consolidated Statements of Operations
Unaudited

(in thousands, except per share amounts)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Operating revenues:				
Oil sales	$ 339,133	$ 470,890	$ 581,287	$ 820,474
Natural gas sales	57,166	66,535	98,576	130,473
Total operating revenues	396,299	537,425	679,863	950,947
Operating costs and expenses:				
Oil and natural gas production	110,224	142,265	225,181	267,800
Exploration and abandonments	21,274	12,020	44,134	17,775
Depreciation, depletion and amortization	280,966	304,802	591,048	572,007
Accretion of discount on asset retirement obligations	1,745	2,047	3,457	4,041
Impairments of long-lived assets	-	-	1,524,645	-
General and administrative (including non-cash stock-based compensation of $12,451 and $15,450 for the three months ended June 30, 2016 and 2015, respectively, and $28,473 and $30,945 for the six months ended June 30, 2016 and 2015, respectively)	53,357	60,923	107,152	119,724
Loss on derivatives	296,694	147,399	216,852	32,059
(Gain) loss on disposition of assets, net	1,137	1,581	(109,929)	1,620
Total operating costs and expenses	765,397	671,037	2,602,540	1,015,026
Loss from operations	(369,098)	(133,612)	(1,922,677)	(64,079)
Other income (expense):				
Interest expense	(54,502)	(53,482)	(108,640)	(107,051)
Other, net	(334)	(4,097)	(6,869)	(8,399)
Total other expense	(54,836)	(57,579)	(115,509)	(115,450)
Loss before income taxes	(423,934)	(191,191)	(2,038,186)	(179,529)
Income tax benefit	158,249	70,708	752,021	66,558
Net loss	$ (265,685)	$ (120,483)	$ (1,286,165)	$ (112,971)
Earnings per share:				
Basic net loss	$ (2.04)	$ (1.02)	$ (9.94)	$ (0.97)
Diluted net loss	$ (2.04)	$ (1.02)	$ (9.94)	$ (0.97)

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

Concho Resources Inc.
Consolidated Statement of Stockholders' Equity
Unaudited

(in thousands)	Common Stock Issued Shares	Common Stock Issued Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Total Stockholders' Equity
BALANCE AT DECEMBER 31, 2015	129,444	$ 129	$ 4,628,390	$ 2,345,641	306	$ (31,609)	$ 6,942,551
Net loss	-	-	-	(1,286,165)	-	-	(1,286,165)
Common stock issued in business combination	2,214	2	230,826	-	-	-	230,828
Stock options exercised	21	1	423	-	-	-	424
Grants of restricted stock	428	-	-	-	-	-	-
Performance unit share conversion	180	-	-	-	-	-	-
Cancellation of restricted stock	(47)	-	-	-	-	-	-
Stock-based compensation	-	-	28,473	-	-	-	28,473
Tax deficiency related to stock-based compensation	-	-	(692)	-	-	-	(692)
Purchase of treasury stock	-	-	-	-	122	(11,713)	(11,713)
BALANCE AT JUNE 30, 2016	132,240	$ 132	$ 4,887,420	$ 1,059,476	428	$ (43,322)	$ 5,903,706

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 thousands)	**2016**	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (1,286,165)	$ (112,971)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	591,048	572,007
Accretion of discount on asset retirement obligations	3,457	4,041
Impairments of long-lived assets	1,524,645	-
Exploration and abandonments, including dry holes	38,550	12,352
Non-cash stock-based compensation expense	28,473	30,945
Deferred income taxes	(740,049)	(95,268)
(Gain) loss on disposition of assets, net	(109,929)	1,620
Loss on derivatives	216,852	32,059
Other non-cash items	8,832	5,298
Changes in operating assets and liabilities, net of acquisitions and dispositions:		
Accounts receivable	59,723	55,870
Prepaid costs and other	(7,886)	(2,098)
Inventory	2,508	(1,935)
Accounts payable	6,956	23,339
Revenue payable	(58,980)	(35,556)
Other current liabilities	(28,210)	(769)
Net cash provided by operating activities	249,825	488,934
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and natural gas properties	(650,889)	(1,492,547)
Additions to property, equipment and other assets	(15,795)	(26,146)
Proceeds from the disposition of assets	294,341	96
Contributions to equity method investments	(39,500)	(45,000)
Net settlements received from derivatives	426,679	279,408
Net cash provided by (used in) investing activities	14,836	(1,284,189)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of debt	-	1,097,400
Payments of debt	-	(1,030,900)
Exercise of stock options	424	58
Excess tax benefit (deficiency) from stock-based compensation	(692)	2,221
Net proceeds from issuance of common stock	-	741,509
Purchase of treasury stock	(11,713)	(4,403)
Decrease in bank overdrafts	-	(10,371)
Net cash provided by (used in) financing activities	(11,981)	795,514
Net increase in cash and cash equivalents	252,680	259
Cash and cash equivalents at beginning of period	228,550	21
Cash and cash equivalents at end of period	$ 481,230	$ 280
NON-CASH INVESTING AND FINANCING ACTIVITIES:		

Issuance of common stock for a business combination	$	230,828	$	-

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

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Condensed Notes to Consolidated Financial Statements

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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 2016 presentation. These reclassifications had no impact on net loss, total stockholders' equity or 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 derivative financial instruments, fair value of business combinations, fair value of nonmonetary exchanges, fair value of stock-based compensation 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, 2015 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, 2015.

Equity method investments. The Company owns a 50 percent membership interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), that constructed a crude oil gathering and transportation system in the northern Delaware Basin. ACC commenced partial operations in late 2015 and completed construction of the pipeline in April 2016. The Company has the option to purchase the membership interest of the other investor in ACC. This purchase option became exercisable in July 2016 and remains exercisable for a period of twelve months. The Company accounts 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 $129.0 million and $98.9 million at June 30, 2016 and December 31, 2015, respectively, and is included in other assets in the Company's consolidated balance sheets. The equity loss for the six months ended June 30,

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2016 and 2015 was approximately $1.9 million and $1.7 million, respectively, and is included in other expense in the Company's consolidated statements of operations. During the six months ended June 30, 2015, the Company recorded $1.5 million of capitalized interest on its investment in ACC.

During 2015, the Company purchased a 25 percent membership interest in an entity constructing a crude oil gathering and transportation system in the southern Delaware Basin. The system is partially operational and is expected to be completed during 2016. The Company accounts for its investment under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment was approximately $26.0 million and $20.8 million at June 30, 2016 and December 31, 2015, respectively, and is included in other assets in the Company's consolidated balance sheets. The equity loss for the six months ended June 30, 2016 was approximately $2.3 million and is included in other expense in the Company's 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 and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $6.0 million and $6.4 million for the three months ended June 30, 2016 and 2015, respectively, and $12.5 million and $12.7 million for the six months ended June 30, 2016 and 2015, respectively.

Recent accounting pronouncements. In May 2014, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("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.

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 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. An entity can apply ASU 2014-09 using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. The Company is evaluating the impact that this new guidance will have 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 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. The Company is evaluating the impact that this new guidance will have on its consolidated financial statements.

In March 2016, the FASB issued ASU No. 2016-09, "Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting," which changes the accounting and presentation for share-based payment arrangements in the following areas: (i) recognition in the statement of operations of excess tax benefits and deficiencies; (ii) cash flow presentation of excess tax benefits and deficiencies; (iii) minimum statutory withholding thresholds and the classification on the cash flow statement of the withheld amounts; and (iv) an accounting policy election to recognize forfeitures as they occur. This guidance is effective for reporting periods beginning after December 15, 2016 and early adoption is permitted. The Company is evaluating the impact that this new guidance will have on its consolidated financial statements.

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 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 16 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, 2016:

(in thousands)		**Six Months Ended June 30, 2016**
Beginning capitalized exploratory well costs	$	116,198
Additions to exploratory well costs pending the determination of proved reserves		103,499
Reclassifications due to determination of proved reserves		(80,227)
Exploratory well costs charged to expense		(5,707)
Disposition of wells		(17,339)
Ending capitalized exploratory well costs	$	116,424

The following table provides an aging at June 30, 2016 and December 31, 2015 of capitalized exploratory well costs based on the date drilling was completed:

(dollars in thousands)	**June 30, 2016**	**December 31, 2015**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 111,545	$ 98,764
Capitalized exploratory well costs that have been capitalized for a period greater than one year	4,879	17,434
Total capitalized exploratory well costs	$ 116,424	$ 116,198
Number of projects with exploratory well costs that have been capitalized for a period greater than one year	6	8

Projects operated by others. At June 30, 2016, the Company had approximately $4.6 million of suspended well costs greater than one year recorded for five wells that are operated by others and waiting on completion. Two of these wells, with suspended well costs totaling approximately $3.1 million, completed drilling in 2012 and are expected to be completed in 2016. The remaining three wells completed drilling in 2014 and are waiting on completion.

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Texas Permian project. At June 30, 2016, the Company had approximately $0.3 million of suspended well costs greater than one year recorded for a well that was initially drilled to monitor nearby pad wells and is expected to be completed in 2016. These costs became greater than one year old during the three months ended March 31, 2016.

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

Asset acquisition. In March 2016, the Company completed an acquisition of 80 percent of a third-party seller's interest in certain oil and natural gas properties and related assets in the southern Delaware Basin. As consideration for the acquisition, the Company issued to the seller approximately 2.2 million shares of common stock with an approximate value of $230.8 million, $146.2 million in cash and $40.0 million to carry a portion of the seller's future development costs in these properties.

Asset divestiture. In February 2016, the Company sold certain assets in the northern Delaware Basin for proceeds of approximately $292.0 million and recognized a pre-tax gain of approximately $110.1 million.

Note 5. ***Asset retirement obligations***

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and facilities. The following table summarizes the Company's asset retirement obligation activity during the six months ended June 30, 2016:

(in thousands)	**Six Months Ended June 30, 2016**
Asset retirement obligations, beginning of period	$ 119,945
Liabilities incurred from new wells	1,004
Liabilities assumed in acquisitions	902
Accretion expense	3,457

Disposition of wells		(970)
Liabilities settled upon plugging and abandoning wells		(899)
Asset retirement obligations, end of period	$	123,439

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Note 6. ***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.

A summary of the Company's activity for the six months ended June 30, 2016 is presented below:

	Restricted Stock	Stock Options	Performance Units
Outstanding at December 31, 2015	1,199,647	42,901	315,755
Awards granted (a)	427,804	-	161,361
Options exercised	-	(20,776)	-
Awards cancelled / forfeited	(46,642)	-	(9,285)
Lapse of restrictions	(378,215)	-	-
Outstanding at June 30, 2016	1,202,594	22,125	467,831
(a) Weighted average grant date fair value per share	$ 111.63	$ -	$ 114.81

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, 2016:

(in thousands)	
Remaining 2016	$ 33,986
2017	44,894
2018	22,267
2019	4,922
2020	152

Total	$	106,221

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Note 7. ***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.

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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, 2016 and December 31, 2015:

	June 30, 2016		December 31, 2015	
(in thousands)	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Assets:				
Derivative instruments	$ 230,779	$ 230,779	$ 819,536	$ 819,536
Liabilities:				
Derivative instruments	$ 54,774	$ 54,774	$ -	$ -
$600 million 7.0% senior notes due 2021 (a)	$ 593,048	$ 621,720	$ 592,414	$ 595,500
$600 million 6.5% senior notes due 2022 (a)	$ 592,125	$ 614,280	$ 591,549	$ 579,000
$600 million 5.5% senior notes due 2022 (a)	$ 593,337	$ 603,000	$ 592,899	$ 553,500
$1,550 million 5.5% senior notes due 2023 (a)	$ 1,555,022	$ 1,577,576	$ 1,555,326	$ 1,453,005

(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, 2016 and December 31, 2015. The Company nets the fair value of derivative instruments by counterparty in the Company’s consolidated balance sheets.

	June 30, 2016					
	Fair Value Measurements Using					Net
(in thousands)	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	$ -	$ 265,181	$ -	$ 265,181	$ (34,402)	$ 230,779
Noncurrent:						
Commodity derivatives	-	12,762	-	12,762	(12,762)	-
Liabilities:						
Current:						
Commodity derivatives	-	(34,814)	-	(34,814)	34,402	(412)
Noncurrent:						
Commodity derivatives	-	(67,124)	-	(67,124)	12,762	(54,362)

Net derivative instruments	$	-	$	176,005	$	-	$	176,005	$	-	$	176,005

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(in thousands)	December 31, 2015 Fair Value Measurements Using: 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	$ -	$ 684,029	$ -	$ 684,029	$ (31,531)	$ 652,498
Noncurrent:						
Commodity derivatives	-	175,267	-	175,267	(8,229)	167,038
Liabilities:						
Current:						
Commodity derivatives	-	(31,531)	-	(31,531)	31,531	-
Noncurrent:						
Commodity derivatives	-	(8,229)	-	(8,229)	8,229	-
Net derivative instruments	$ -	$ 819,536	$ -	$ 819,536	$ -	$ 819,536

Concentrations of credit risk. At June 30, 2016, 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 8 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, 2016, 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 2016 price of $49.54 per barrel of oil and $3.04 per Mcf of natural gas to a 2023 price of $57.77 per barrel of oil and $3.50 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2023.

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) 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 thousands)	**Carrying Amount**	**Estimated Fair Value (Level 3)**	**Impairment Expense**
March 2016	$ 3,437,612	$ 1,912,967	$ 1,524,645

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 8. ***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 may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these physical delivery contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

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 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, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
Gain (loss) on derivatives:				
Oil derivatives	$ (279,805)	$ (146,549)	$ (208,665)	$ (36,269)
Natural gas derivatives	(16,889)	(850)	(8,187)	4,210
Total	$ (296,694)	$ (147,399)	$ (216,852)	$ (32,059)

The following table represents the Company's net cash receipts from derivatives for the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
Net cash receipts from derivatives:				
Oil derivatives	$ 160,968	$ 103,129	$ 412,095	$ 263,315
Natural gas derivatives	7,781	9,123	14,584	16,093
Total	$ 168,749	$ 112,252	$ 426,679	$ 279,408

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Commodity derivative contracts at June 30, 2016. The following table sets forth the Company's outstanding derivative contracts at June 30, 2016. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at June 30, 2016 are expected to settle by December 31, 2018.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2016:					
Volume (Bbl)			5,460,000	5,054,000	10,514,000
Price per Bbl			$ 74.21	$ 59.38	$ 67.08
2017:					
Volume (Bbl)	5,278,000	4,903,000	4,592,000	4,337,000	19,110,000
Price per Bbl	$ 58.73	$ 59.35	$ 51.04	$ 51.33	$ 55.36
2018:					
Volume (Bbl)	1,920,000	1,920,000	1,920,000	1,920,000	7,680,000
Price per Bbl	$ 48.73	$ 48.73	$ 48.73	$ 48.73	$ 48.73
Oil Basis Swaps: (b)					
2016:					
Volume (Bbl)			5,520,000	5,060,000	10,580,000
Price per Bbl			$ (1.46)	$ (1.48)	$ (1.47)
2017:					
Volume (Bbl)	4,590,000	4,519,000	3,496,000	3,496,000	16,101,000
Price per Bbl	$ (1.16)	$ (1.18)	$ (0.43)	$ (0.43)	$ (0.85)
Natural Gas Swaps: (c)					
2016:					
Volume (MMBtu)			7,360,000	7,360,000	14,720,000
Price per MMBtu			$ 3.02	$ 3.02	$ 3.02
2017:					
Volume (MMBtu)	10,350,000	10,465,000	9,660,000	9,660,000	40,135,000
Price per MMBtu	$ 3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00

(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 revolving 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.

At June 30, 2016, the Company had a net asset position of $176.0 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 $40.3 million, $26.9 million, $21.0 million and $19.7 million with Barclays Bank PLC, J.P. Morgan Chase Bank, Wells Fargo Bank, N.A. and Societe Generale, respectively.

Note 9. *Debt*

The Company's debt consisted of the following at June 30, 2016 and December 31, 2015:

(in thousands)		**June 30, 2016**		**December 31, 2015**
Credit facility	$	-	$	-
7.0% unsecured senior notes due 2021		600,000		600,000
6.5% unsecured senior notes due 2022		600,000		600,000
5.5% unsecured senior notes due 2022		600,000		600,000
5.5% unsecured senior notes due 2023		1,550,000		1,550,000
Unamortized original issue premium		23,642		25,073
Senior notes issuance costs, net		(40,110)		(42,885)
Less: current portion		-		-
Total long-term debt	$	3,333,532	$	3,332,188

Credit facility. The Company's credit facility, as amended and restated, has a maturity date of May 9, 2019. At June 30, 2016, the Company's commitments from its bank group were $2.5 billion. The Company expects it will maintain its $2.5 billion in commitments until its next scheduled redetermination in May 2017. At June 30, 2016, the Company's borrowing base was $2.8 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 14.

At June 30, 2016, 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, 2016 were as follows:

(in thousands)		
Remaining 2016	$	-
2017		-
2018		-
2019		-
2020		-
2021		600,000
Thereafter		2,750,000
Total	$	3,350,000

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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, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
Cash payments for interest	$ 63,017	$ 59,225	$ 105,507	$ 105,232
Amortization of original issue premium	(720)	(681)	(1,431)	(1,355)
Amortization of deferred loan origination costs	2,567	2,482	5,113	4,945
Accretion expense	485	-	971	-
Net changes in accruals	(10,847)	(6,365)	(1,268)	618
Interest costs incurred	54,502	54,661	108,892	109,440
Less: capitalized interest	-	(1,179)	(252)	(2,389)
Total interest expense	$ 54,502	$ 53,482	$ 108,640	$ 107,051

Note 10. *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 June 30, 2016 and December 31, 2015, the Company had $13.8 million and $13.4 million, respectively, accrued for estimated exposure. 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 and maintenance commitments. The following table summarizes the Company's commitments at June 30, 2016:

(in thousands)		
Remaining 2016	$	29,573
2017		24,186
2018		63,057
2019		17,294
2020		11,797
2021		7,317
Thereafter		37,921
Total	$	191,145

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, 2016 and 2015 were approximately $2.1 million and $1.9 million, respectively, and approximately $4.2 million and $3.8 million for the six months ended June 30, 2016 and 2015, respectively.

Future minimum lease commitments under non-cancellable operating leases at June 30, 2016 were as follows:

(in thousands)		
Remaining 2016	$	4,231
2017		8,458
2018		7,637
2019		6,169
2020		4,866

2021		4,147
Thereafter		994
Total	$	36,502

Note 11. ***Income taxes***

The effective income tax rates were 37.3 percent and 37.0 percent for the three months ended June 30, 2016 and 2015, respectively, and 36.9 percent and 37.1 percent for the six months ended June 30, 2016 and 2015, respectively. Total income tax benefit for the three and six months ended June 30, 2016 and 2015 differed from amounts computed by applying the United States federal statutory tax rates to pre-tax loss due primarily to state taxes and the impact of permanent differences between book and taxable income.

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Note 12. ***Related party transactions***

The following table summarizes amounts paid to and received from related parties and reported in the Company's consolidated statements of operations for the periods presented:

(in thousands)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Amounts paid to a partnership in which a director has an ownership interest (a)	$ 999	$ 1,403	$ 2,144	$ 3,097
Amounts paid to a director and certain officers of the Company (b)	$ 75	$ 32	$ 235	$ 555
Amounts received from certain officers of the Company (c)	$ 4	$ 52	$ 20	$ 67

(a) Amounts include royalties on certain properties paid to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest.

(b) Amounts include revenue interests, overriding royalty interests and net profits interests in properties owned by the Company made to a director and certain officers (or affiliated entities). Amounts also include payments for lease bonuses to an affiliated entity of an officer.

(c) Amounts include payments to the Company as a result of activity on oil and natural gas properties in which certain officers (or affiliated entities) have an interest.

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Note 13. ***Net loss per share***

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

The following table reconciles the Company's net loss from operations and loss attributable to common stockholders to the basic and diluted earnings used to determine the Company's net loss per share amounts for the three and six months ended June 30, 2016 and 2015, respectively, under the two-class method:

(in thousands, except per share amounts)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net loss as reported	$ (265,685)	$ (120,483)	$ (1,286,165)	$ (112,971)
Participating basic earnings (a)	-	-	-	-
Basic loss attributable to common stockholders	(265,685)	(120,483)	(1,286,165)	(112,971)
Reallocation of participating earnings	-	-	-	-
Diluted loss attributable to common stockholders	$ (265,685)	$ (120,483)	$ (1,286,165)	$ (112,971)
Loss per common share:				
Basic	$ (2.04)	$ (1.02)	$ (9.94)	$ (0.97)
Diluted	$ (2.04)	$ (1.02)	$ (9.94)	$ (0.97)

(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.

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, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2016**	**2015**	**2016**	**2015**
Weighted average common shares outstanding:				
Basic	130,400	117,637	129,398	116,502
Dilutive common stock options	-	-	-	-
Dilutive performance units	-	-	-	-
Diluted	130,400	117,637	129,398	116,502

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 14. ***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 9 for a summary of the Company’s senior notes. In accordance with practices accepted by the United States Securities and Exchange Commission (“SEC”), 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, 2016 and December 31, 2015, condensed consolidating statements of operations for the three and six months ended June 30, 2016 and 2015 and condensed consolidating statements of cash flows for the six months ended June 30, 2016 and 2015, 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, 2016

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,853,785	$ 898,972	$ (9,752,757)	$ -
Other current assets	284,704	827,286	-	1,111,990
Oil and natural gas properties, net	-	9,382,478	-	9,382,478
Property and equipment, net	-	183,966	-	183,966
Investment in subsidiaries	1,985,134	-	(1,985,134)	-
Other long-term assets	25,418	197,765	-	223,183
Total assets	$ 11,149,041	$ 11,490,467	$ (11,737,891)	$ 10,901,617
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ 898,972	$ 8,853,785	$ (9,752,757)	$ -
Other current liabilities	68,145	507,445	-	575,590
Long-term debt	3,333,532	-	-	3,333,532
Other long-term liabilities	944,686	144,103	-	1,088,789
Equity	5,903,706	1,985,134	(1,985,134)	5,903,706
Total liabilities and equity	$ 11,149,041	$ 11,490,467	$ (11,737,891)	$ 10,901,617

Condensed Consolidating Balance Sheet
December 31, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 8,502,099	$ 1,162,297	$ (9,664,396)	$ -
Other current assets	753,716	560,834	-	1,314,550
Oil and natural gas properties, net	-	10,798,497	-	10,798,497
Property and equipment, net	-	178,450	-	178,450
Investment in subsidiaries	3,698,485	-	(3,698,485)	-
Other long-term assets	182,623	167,756	-	350,379
Total assets	$ 13,136,923	$ 12,867,834	$ (13,362,881)	$ 12,641,876

LIABILITIES AND EQUITY								
Accounts payable - related parties	$	1,162,297	$	8,502,099	$	(9,664,396)	$	-
Other current liabilities		69,514		526,906		-		596,420
Long-term debt		3,332,188		-		-		3,332,188
Other long-term liabilities		1,630,373		140,344		-		1,770,717
Equity		6,942,551		3,698,485		(3,698,485)		6,942,551
Total liabilities and equity	$	13,136,923	$	12,867,834	$	(13,362,881)	$	12,641,876

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

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 396,299	$ -	$ 396,299
Total operating costs and expenses	(297,205)	(468,192)	-	(765,397)
Loss from operations	(297,205)	(71,893)	-	(369,098)
Interest expense	(53,655)	(847)	-	(54,502)
Other, net	(73,074)	(334)	73,074	(334)
Loss before income taxes	(423,934)	(73,074)	73,074	(423,934)
Income tax benefit	158,249	-	-	158,249
Net loss	$ (265,685)	$ (73,074)	$ 73,074	$ (265,685)

Condensed Consolidating Statement of Operations
Three Months Ended June 30, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 537,425	$ -	$ 537,425
Total operating costs and expenses	(148,039)	(522,998)	-	(671,037)
Income (loss) from operations	(148,039)	14,427	-	(133,612)
Interest expense	(53,482)	-	-	(53,482)
Other, net	10,330	(4,097)	(10,330)	(4,097)
Income (loss) before income taxes	(191,191)	10,330	(10,330)	(191,191)
Income tax benefit	70,708	-	-	70,708
Net income (loss)	$ (120,483)	$ 10,330	$ (10,330)	$ (120,483)

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2016

Unaudited

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

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 679,863	$ -	$ 679,863
Total operating costs and expenses	(217,889)	(2,384,651)	-	(2,602,540)
Loss from operations	(217,889)	(1,704,788)	-	(1,922,677)
Interest expense	(106,946)	(1,694)	-	(108,640)
Other, net	(1,713,351)	(6,869)	1,713,351	(6,869)
Loss before income taxes	(2,038,186)	(1,713,351)	1,713,351	(2,038,186)
Income tax benefit	752,021	-	-	752,021
Net loss	$ (1,286,165)	$ (1,713,351)	$ 1,713,351	$ (1,286,165)

Condensed Consolidating Statement of Operations
Six Months Ended June 30, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 950,947	$ -	$ 950,947
Total operating costs and expenses	(33,435)	(981,591)	-	(1,015,026)
Loss from operations	(33,435)	(30,644)	-	(64,079)
Interest expense	(107,051)	-	-	(107,051)
Other, net	(39,043)	(8,399)	39,043	(8,399)
Loss before income taxes	(179,529)	(39,043)	39,043	(179,529)
Income tax benefit	66,558	-	-	66,558
Net loss	$ (112,971)	$ (39,043)	$ 39,043	$ (112,971)

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2016

Unaudited

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

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (414,698)	$ 664,523	$ -	$ 249,825
Net cash flows provided by (used in) investing activities	426,679	(411,843)	-	14,836
Net cash flows used in financing activities	(11,981)	-	-	(11,981)
Net increase in cash and cash equivalents	-	252,680	-	252,680
Cash and cash equivalents at beginning of period	-	228,550	-	228,550
Cash and cash equivalents at end of period	$ -	$ 481,230	$ -	$ 481,230

Condensed Consolidating Statement of Cash Flows
Six Months Ended June 30, 2015

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (1,085,293)	$ 1,574,227	$ -	$ 488,934
Net cash flows provided by (used in) investing activities	279,408	(1,563,597)	-	(1,284,189)
Net cash flows provided by (used in) financing activities	805,885	(10,371)	-	795,514
Net increase in cash and cash equivalents	-	259	-	259
	-	21	-	21

Cash and cash equivalents at beginning of period				
Cash and cash equivalents at end of period	$ -	$ 280	$ -	$ 280

Note 15. ***Subsequent events***

New commodity derivative contracts. After June 30, 2016, the Company entered into the following oil price swaps, oil basis swaps and natural gas price swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2018:					
Volume (Bbl)	390,000	390,000	390,000	390,000	1,560,000
Price per Bbl	$ 49.24	$ 49.24	$ 49.24	$ 49.24	$ 49.24
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)	360,000	364,000	368,000	368,000	1,460,000
Price per Bbl	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)
Natural Gas Swaps: (c)					
2017:					
Volume (MMBtu)	1,985,315	1,066,642	1,110,441	920,000	5,082,398
Price per MMBtu	$ 3.21	$ 3.16	$ 3.16	$ 3.14	$ 3.18

(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.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

Concho Resources Inc.

Condensed Notes to Consolidated Financial Statements

June 30, 2016

Unaudited

Note 16. ***Supplementary information***

Capitalized costs

(in thousands)	June 30, 2016	December 31, 2015
Oil and natural gas properties:		
Proved	$ 15,559,042	$ 14,940,259
Unproved	931,288	906,048
Less: accumulated depletion	(7,107,852)	(5,047,810)
Net capitalized costs for oil and natural gas properties	$ 9,382,478	$ 10,798,497

Costs incurred for oil and natural gas producing activities

(in thousands)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Property acquisition costs:				
Proved	$ 3,757	$ 2,243	$ 256,109	$ 2,243
Unproved	18,767	18,037	157,407	34,050
Exploration	165,850	343,051	336,422	772,220
Development	107,039	221,410	190,143	523,154
Total costs incurred for oil and natural gas properties	$ 295,413	$ 584,741	$ 940,081	$ 1,331,667

The table below provides the amount of asset retirement obligations included in the costs incurred table shown above:

(in thousands)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Exploration costs	$ 352	$ 737	$ 583	$ 1,355
Development costs	192	573	421	1,508
Total asset retirement obligations	$ 544	$ 1,310	$ 1,004	$ 2,863

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 also at the forefront of applying new technologies, such as horizontal drilling and enhanced completion techniques, throughout our three core operating areas: the New Mexico Shelf, the Delaware Basin and the Midland Basin. In the New Mexico Shelf, we primarily target the Yeso formation with horizontal drilling; in the Delaware Basin, we use horizontal drilling to target the Bone Spring formation (including the Avalon shale and the Bone Spring sands) and the Wolfcamp shale formation; and in the Midland Basin, we target the Wolfcamp and Spraberry formations with horizontal drilling. Oil comprised 59 percent of our 623.5 MMBoe of estimated proved reserves at December 31, 2015 and 62.7 percent of our 25.9 MMBoe of production for the six months ended June 30, 2016. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 93 percent of our proved developed producing PV-10 and 78.9 percent of our 7,636 gross wells at December 31, 2015. 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, 2016 and 2015 included the following highlights:

- Net loss was $1.3 billion ($(9.94) per diluted share) as compared to net loss of $113.0 million ($(0.97) per diluted share) for the first six months of 2016 and 2015, respectively. The increase in net loss was primarily due to:

- $1.5 billion in impairments of long-lived assets during the six months ended June 30, 2016, primarily attributable to properties in our New Mexico Shelf area;

- $271.1 million decrease in oil and natural gas revenues as a result of a 30 percent decrease in commodity price realizations per Boe (excluding the effects of derivative activities), partially offset by a 2 percent increase in production;

- $184.8 million increase in the loss on derivatives during the six months ended June 30, 2016, as compared to 2015;

- $26.4 million increase in exploration and abandonment expense primarily due to leasehold abandonments during the six months ended June 30, 2016 as compared to 2015; and

- $19.0 million increase in depreciation, depletion and amortization expense, primarily due to an increase in production;

partially offset by:

- $685.5 million change in our income tax benefit due to the increase in our net loss before income taxes;

- $111.5 million increase in (gain) loss on disposition of assets, net primarily due to our February 2016 asset divestiture; and

- $42.6 million decrease in oil and natural gas production expense.

- Average daily sales volumes of 142,319 Boe per day during the first six months of 2016 were up slightly as compared to 139,826 Boe per day during the first six months of 2015.

- Net cash provided by operating activities decreased by approximately $239.1 million to $249.8 million for the first six months of 2016, as compared to $488.9 million in the first six months of 2015, primarily due to a decrease in oil and natural gas revenues, partially offset by a decrease in production and cash general and administrative expenses.

- Cash increased by approximately $252.7 million during the first six months of 2016 primarily as a result of operating cash flows and our divestiture that closed in February 2016, partially offset by the cash consideration related to our asset acquisition that closed in March 2016.

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 continue to manage oil prices and production controls;

- 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 and natural gas commodity 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 8 and 15 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, 2016 and additional derivative contracts entered into subsequent to June 30, 2016, respectively.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. In general, average oil and natural gas prices were significantly lower during the comparable periods of 2016 measured against 2015. 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, 2016 and 2015, as well as the high and low NYMEX prices for the same periods:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2016	**2015**	**2016**	**2015**
Average NYMEX prices:				
Oil (Bbl)	$ 45.56	$ 57.80	$ 39.65	$ 53.33
Natural gas (MMBtu)	$ 2.24	$ 2.74	$ 2.12	$ 2.78
High and Low NYMEX prices:				
Oil (Bbl):				
High	$ 51.23	$ 61.43	$ 51.23	$ 61.43
Low	$ 35.70	$ 49.14	$ 26.21	$ 43.46
Natural gas (MMBtu):				
High	$ 2.92	$ 3.02	$ 2.92	$ 3.23
Low	$ 1.90	$ 2.49	$ 1.64	$ 2.49

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $48.99 and $40.06 per Bbl and $3.02 and $2.66 per MMBtu, respectively, during the period from July 1, 2016 to August 1, 2016. At August 1, 2016, the NYMEX oil price and NYMEX natural gas price were $40.06 per Bbl and $2.77 per MMBtu, respectively.

Recent Events

Asset acquisition. In March 2016, we completed an acquisition of 80 percent of a third-party seller's interest in certain oil and natural gas properties and related assets in the southern Delaware Basin. As consideration for the acquisition, we issued to the seller approximately 2.2 million shares of common stock with an approximate value of $230.8 million, $146.2 million in cash and $40.0 million to carry a portion of the seller's future development costs in these properties.

Asset divestiture. In February 2016, we sold certain assets in the northern Delaware Basin for proceeds of approximately $292.0 million and recognized a pre-tax gain of approximately $110.1 million.

Derivative Financial Instruments

Derivative financial instrument exposure. At June 30, 2016, the fair value of our financial derivatives was a net asset of $176.0 million. All of our counterparties to these financial derivatives are parties or affiliates of parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. 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. 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 or its affiliates.

New commodity derivative contracts. After June 30, 2016, we entered into the following oil price swaps, oil basis swaps and natural gas price swaps to hedge additional amounts of our estimated future production:

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
Oil Swaps: (a)					
2018:					
Volume (Bbl)	390,000	390,000	390,000	390,000	1,560,000
Price per Bbl	$ 49.24	$ 49.24	$ 49.24	$ 49.24	$ 49.24
Oil Basis Swaps: (b)					
2017:					
Volume (Bbl)	360,000	364,000	368,000	368,000	1,460,000
Price per Bbl	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)	$ (0.50)

Natural Gas Swaps: (c)					
2017:					
Volume (MMBtu)	1,985,315	1,066,642	1,110,441	920,000	5,082,398
Price per MMBtu	$ 3.21	$ 3.16	$ 3.16	$ 3.14	$ 3.18

(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.

The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.

(c)

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, 2016 and 2015. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of 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,	
	2016	**2015**	**2016**	**2015**
Production and operating data:				
Net production volumes:				
Oil (MBbl)	8,137	9,031	16,237	17,097
Natural gas (MMcf)	30,434	26,283	57,991	49,268
Total (MBoe)	13,209	13,412	25,902	25,308
Average daily production volumes:				
Oil (Bbl)	89,418	99,242	89,214	94,459
Natural gas (Mcf)	334,440	288,824	318,632	272,199
Total (Boe)	145,158	147,379	142,319	139,826
Average prices per unit:				
Oil, without derivatives (Bbl)	$ 41.68	$ 52.14	$ 35.80	$ 47.99
Oil, with derivatives (Bbl) (a)	$ 61.46	$ 63.56	$ 61.18	$ 63.39
Natural gas, without derivatives (Mcf)	$ 1.88	$ 2.53	$ 1.70	$ 2.65
Natural gas, with derivatives (Mcf) (a)	$ 2.13	$ 2.88	$ 1.95	$ 2.97
Total, without derivatives (Boe)	$ 30.00	$ 40.07	$ 26.25	$ 37.57
Total, with derivatives (Boe) (a)	$ 42.78	$ 48.44	$ 42.72	$ 48.62
Operating costs and expenses per Boe:				
Lease operating expenses and workover costs	$ 5.83	$ 7.30	$ 6.54	$ 7.46
Oil and natural gas taxes	$ 2.51	$ 3.30	$ 2.15	$ 3.12
Depreciation, depletion and amortization	$ 21.27	$ 22.72	$ 22.82	$ 22.60
General and administrative	$ 4.04	$ 4.54	$ 4.14	$ 4.73

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

(in thousands)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net cash receipts from derivatives:				
Oil derivatives	$ 160,968	$ 103,129	$ 412,095	$ 263,315
Natural gas derivatives	7,781	9,123	14,584	16,093
Total	$ 168,749	$ 112,252	$ 426,679	$ 279,408

The presentation of average prices with derivatives is a result of including the net cash receipts from 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, 2016 Compared to Three Months Ended June 30, 2015

Oil and natural gas revenues. Revenue from oil and natural gas operations was $396.3 million for the three months ended June 30, 2016, a decrease of $141.1 million (26 percent) from $537.4 million for 2015. This decrease was primarily due to the decrease in realized oil and natural gas prices. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 8,137 MBbl for the three months ended June 30, 2016, a decrease of 894 MBbl from 9,031 MBbl for 2015;

- average realized oil price (excluding the effects of derivative activities) was $41.68 per Bbl during the three months ended June 30, 2016, a decrease of 20 percent from $52.14 per Bbl during 2015. For the three months ended June 30, 2016, our crude oil price differential relative to NYMEX was $(3.88) per Bbl, or a realization of approximately 91.5 percent, as compared to a crude oil price differential relative to NYMEX of $(5.66) per Bbl, or a realization of approximately 90.2 percent, for 2015. We incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. Additionally, 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, 2016 and 2015, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.17 per Bbl and $0.60 per Bbl, respectively;

- total natural gas production was 30,434 MMcf for the three months ended June 30, 2016, an increase of 4,151 MMcf (16 percent) from 26,283 MMcf for 2015; and

- average realized natural gas price (excluding the effects of derivative activities) was $1.88 per Mcf during the three months ended June 30, 2016, a decrease of 26 percent from $2.53 per Mcf during 2015. For the three months ended June 30, 2016 and 2015, we realized approximately 83.9 percent and 92.3 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Factors contributing to the decrease in our realized gas price (excluding the effects of derivatives) as a percent of NYMEX during the three months ended June 30, 2016 as compared to 2015 include (i) a decrease in the posted regional natural gas prices on which we are paid while the NYMEX natural gas price decreased at a lesser rate, (ii) increased deductions and fees from the natural gas price on which we are paid, comparatively and (iii) the average Mont Belvieu price of $18.16 per Bbl compared to $18.67 per Bbl during the three months ended June 30, 2016 and 2015 respectively.

During December 2015, a third-party natural gas processing plant located in the northern Delaware Basin became inoperable following an explosion. The plant became fully operational during April 2016.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,			
	2016		2015	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Lease operating expenses	$ 72,282	$ 5.47	$ 92,059	$ 6.86
Workover costs	4,793	0.36	5,886	0.44
Taxes:				
Ad valorem	3,358	0.25	6,308	0.47
Production	29,791	2.26	38,012	2.83
Total oil and natural gas production expenses	$ 110,224	$ 8.34	$ 142,265	$ 10.60

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are related to commodity prices.

Lease operating expenses were $72.3 million ($5.47 per Boe) for the three months ended June 30, 2016, which was a decrease of $19.8 million from $92.1 million ($6.86 per Boe) for the three months ended June 30, 2015. The decrease in lease operating expenses during the second quarter of 2016 as compared to 2015 was due primarily to (i) a focused effort to identify operational cost efficiencies, (ii) reduced water disposal costs and (iii) an overall decrease in the costs for goods and services. The decrease in lease operating expenses per Boe was primarily due to the reduction in lease operating expenses noted above while production remained relatively flat period over period.

Workover expenses were approximately $4.8 million and $5.9 million for the three months ended June 30, 2016 and 2015, respectively. The decrease was primarily related to less overall activity during the second quarter of 2016 as compared to 2015.

Production taxes per unit of production were $2.26 per Boe during the three months ended June 30, 2016, a decrease of 20 percent from $2.83 per Boe during 2015. Over the same period, our revenue per Boe prices (excluding the effects of derivatives) decreased 25 percent. The decrease in production taxes per unit of production was directly related to the decrease in oil and natural gas prices. Included in the second quarter of 2015 were tax credits of approximately $1.3 million that related to certain wells in Texas qualifying for reduced severance taxes. Notwithstanding the impact of these tax credits, production taxes per unit of production would have decreased 24 percent period over period.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,	
(in thousands)	**2016**	**2015**
Geological and geophysical	$ 3,154	$ 2,054
Exploratory dry hole costs	6,701	8,208
Leasehold abandonments	11,197	1,444
Other	222	314
Total exploration and abandonments	$ 21,274	$ 12,020

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. Our exploratory dry hole costs during the three months ended June 30, 2015 were primarily related to an uneconomic well in our Delaware Basin area that was attempting to establish production in a zone not previously producing in the general area.

For the three months ended June 30, 2016 and 2015, we recorded approximately $11.2 million and $1.4 million, respectively, of leasehold abandonments. For the three months ended June 30, 2016, our abandonments were primarily within our Delaware Basin 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, 2016 and 2015:

	Three Months Ended June 30,			
	2016		**2015**	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 275,299	$ 20.84	$ 299,812	$ 22.35
Depreciation of other property and equipment	5,301	0.40	4,624	0.34
Amortization of intangible assets - operating rights	366	0.03	366	0.03

Total depletion, depreciation and amortization	$	280,966	$	21.27	$	304,802	$	22.72
Oil price used to estimate proved oil reserves at period end	$	39.63			$	68.17		
Natural gas price used to estimate proved natural gas reserves at period end	$	2.24			$	3.39		

Depletion of proved oil and natural gas properties was $275.3 million ($20.84 per Boe) for the three months ended June 30, 2016, a decrease of $24.5 million (8 percent) from $299.8 million ($22.35 per Boe) for 2015. The decrease in depletion expense was primarily due to a lower depletion rate per Boe coupled with a slight decrease in production. The decrease in depletion expense per Boe period over period was primarily due to a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016, partially offset by an overall decrease in proved reserves period over period caused by (i) lower commodity prices and (ii) reclassification of proved reserves to unproven that are no longer expected to be developed within the five years of their initial recording as required by SEC rules, which were partially offset by capital cost reductions.

The increase in depreciation expense was primarily associated with additional other property and equipment related to buildings and other items.

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 calculate the expected 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, 2016, our estimates of commodity prices for purposes of determining undiscounted future cash flows are based on the NYMEX strip, which ranged from a 2016 price of $49.54 per barrel of oil and $3.04 per Mcf of natural gas to a 2023 price of $57.77 per barrel of oil and $3.50 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2023.

We calculate the estimated 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, 2016.

It is reasonably possible that the estimate of undiscounted future net cash flows 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) changes in income and expenses from integrated assets. If the oil and natural gas prices used in this analysis would have been approximately 10 percent lower as of June 30, 2016 with no other changes in capital costs, operating costs, price differentials, or reserve volumes, no impairment would be indicated.

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,			
	2016		2015	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 46,872	$ 3.55	$ 51,847	$ 3.87
Non-cash stock-based compensation	12,451	0.94	15,450	1.15
Less: Third-party operating fee reimbursements	(5,966)	(0.45)	(6,374)	(0.48)
Total general and administrative expenses	$ 53,357	$ 4.04	$ 60,923	$ 4.54

General and administrative expenses were approximately $53.4 million ($4.04 per Boe) for the three months ended June 30, 2016, a decrease of $7.5 million (12 percent) from $60.9 million ($4.54 per Boe) for 2015. The decrease in cash general and administrative expenses was primarily a result of a general company-wide initiative to reduce general and administrative costs, while the decrease in non-cash stock-based compensation was primarily due to an increase in forfeiture estimates. The decrease in total general and administrative expenses per Boe was primarily due to the reduction in general and administrative costs noted above while production remained relatively flat period over period.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $6.0 million and $6.4 million during the three months ended June 30, 2016 and 2015, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Loss on derivatives. The following table sets forth the loss on derivatives for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,	
(in thousands)	**2016**	**2015**
Loss on derivatives:		
Oil derivatives	$ (279,805)	$ (146,549)
Natural gas derivatives	(16,889)	(850)
Total	$ (296,694)	$ (147,399)

The following table represents our net cash receipts from derivatives for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,	
(in thousands)	**2016**	**2015**
Net cash receipts from derivatives:		
Oil derivatives	$ 160,968	$ 103,129
Natural gas derivatives	7,781	9,123
Total	$ 168,749	$ 112,252

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 future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,	
(dollars in thousands)	**2016**	**2015**
Interest expense, as reported	$ 54,502	$ 53,482
Capitalized interest	-	1,179
Interest expense, excluding impact of capitalized interest	$ 54,502	$ 54,661
Weighted average interest rate - credit facility	-	3.0%

Weighted average interest rate - senior notes		5.9%		5.9%
Total weighted average interest rate		5.9%		5.8%
Weighted average credit facility balance	$	-	$	156,340
Weighted average senior notes balance		3,350,000		3,350,000
Total weighted average debt balance	$	3,350,000	$	3,506,340

The decrease in the weighted average debt balance for the three months ended June 30, 2016 as compared to 2015 was due to the repayment of our credit facility using a portion of the proceeds from our October 2015 equity offering. The increase in interest expense was due to a reduction in capitalized interest period over period, partially offset by an overall decrease in the weighted average debt balance.

Income tax provisions. We recorded an income tax benefit of $158.2 million and $70.7 million for the three months ended June 30, 2016 and 2015, respectively. The change in our income tax benefit was primarily due to the increase in our net loss before income taxes. The effective income tax rates for the three months ended June 30, 2016 and 2015 were 37.3 percent and 37.0 percent, respectively.

Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Oil and natural gas revenues. Revenue from oil and natural gas operations was $679.9 million for the six months ended June 30, 2016, a decrease of $271.1 million (28 percent) from $950.9 million for 2015. This decrease was primarily due to the decrease in realized oil and natural gas prices. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 16,237 MBbl for the six months ended June 30, 2016, a decrease of 860 MBbl (5 percent) from 17,097 MBbl for 2015;

- average realized oil price (excluding the effects of derivative activities) was $35.80 per Bbl during the six months ended June 30, 2016, a decrease of 25 percent from $47.99 per Bbl during 2015. For the six months ended June 30, 2016, our crude oil price differential relative to NYMEX was $(3.85) per Bbl, or a realization of approximately 90.3 percent, as compared to a crude oil price differential relative to NYMEX of $(5.34) per Bbl, or a realization of approximately 90.0 percent, for 2015. We incur fixed deductions from the posted Midland oil price based on the location of our oil within the Permian Basin. Additionally, 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, 2016 and 2015, the average market basis differential between WTI-Midland and WTI-Cushing was a price reduction of $0.01 per Bbl and $1.29 per Bbl, respectively;

- total natural gas production was 57,991 MMcf for the six months ended June 30, 2016, an increase of 8,723 MMcf (18 percent) from 49,268 MMcf for 2015; and

- average realized natural gas price (excluding the effects of derivative activities) was $1.70 per Mcf during the six months ended June 30, 2016, a decrease of 36 percent from $2.65 per Mcf during 2015. For the six months ended June 30, 2016 and 2015, we realized approximately 80.2 percent and 95.3 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Factors contributing to the decrease in our realized gas price (excluding the effects of derivatives) as a percent of NYMEX during the six months ended June 30, 2016 as compared to 2015 were (i) a decrease in the posted regional natural gas prices on which we are paid while the NYMEX natural gas price decreased at a lesser rate, (ii) increased deductions and fees from the regional natural gas price, comparatively and (iii) the average Mont Belvieu price of $16.32 per Bbl compared to $18.99 per Bbl during the six months ended June 30, 2016 and 2015 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.

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Production expenses. The following table provides the components of our total oil and natural gas production costs for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,			
	2016		2015	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
Lease operating expenses	$ 159,334	$ 6.15	$ 175,717	$ 6.94
Workover costs	10,173	0.39	13,097	0.52
Taxes:				
Ad valorem	8,880	0.34	11,563	0.46
Production	46,794	1.81	67,423	2.66
Total oil and natural gas production expenses	$ 225,181	$ 8.69	$ 267,800	$ 10.58

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are related to commodity prices.

Lease operating expenses were $159.3 million ($6.15 per Boe) for the six months ended June 30, 2016, which was a decrease of $16.4 million from $175.7 million ($6.94 per Boe) for the six months ended June 30, 2015. The decrease in lease operating expenses during the six months ended June 30, 2016 as compared to 2015 was due primarily to (i) a focused effort to identify operational cost efficiencies and (ii) an overall decrease in the costs for goods and services. The decrease in lease operating expenses per Boe was primarily due to the reduction in lease operating expenses noted above while there was a slight increase in production period over period.

Workover expenses were approximately $10.2 million and $13.1 million for the six months ended June 30, 2016 and 2015, respectively. The decrease was primarily related to less overall activity during 2016 as compared to 2015.

Production taxes per unit of production were $1.81 per Boe during the six months ended June 30, 2016, a decrease of 32 percent from $2.66 per Boe during 2015. The decrease was directly related to the decrease in oil and natural gas prices and due to tax credits of approximately $3.7 million received during the first quarter of 2016 related to certain wells in Texas qualifying for reduced severance tax rates as compared to approximately $1.3 million of similar tax credits received during the second quarter of 2015. Over the same period, our revenue per Boe prices (excluding the effects of derivatives) decreased 30 percent.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
(in thousands)	**2016**	**2015**
Geological and geophysical	$ 4,502	$ 3,486
Exploratory dry hole costs	6,701	8,989
Leasehold abandonments	31,849	3,363
Other	1,082	1,937
Total exploration and abandonments	$ 44,134	$ 17,775

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. Our exploratory dry hole costs during the six months ended June 30, 2015 were primarily related to (i) an uneconomic well in our Delaware Basin area that was attempting to establish production in a zone not previously producing in the general area and (ii) expensing an unsuccessful well, which we did not operate, that was located in our New Mexico Shelf area.

For the six months ended June 30, 2016 and 2015, we recorded approximately $31.8 million and $3.4 million, respectively, of leasehold abandonments. 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, 2016 and 2015:

	Six Months Ended June 30,			
	2016		**2015**	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**

Depletion of proved oil and natural gas properties	$	580,044	$	22.39	$	562,092	$	22.21
Depreciation of other property and equipment		10,273		0.40		9,184		0.36
Amortization of intangible assets - operating rights		731		0.03		731		0.03
Total depletion, depreciation and amortization	$	591,048	$	22.82	$	572,007	$	22.60

Depletion of proved oil and natural gas properties was $580.0 million ($22.39 per Boe) for the six months ended June 30, 2016, an increase of $17.9 million (3 percent) from $562.1 million ($22.21 per Boe) for 2015. The increase in depletion expense was primarily due to a modest increase in production in addition to a slightly higher depletion rate per Boe period over period. The increase in depletion expense per Boe period over period was primarily due to a decrease in proved reserves caused by (i) lower commodity prices period over period and (ii) reclassification of proved reserves to unproven that are no longer expected to be developed within the five years of their initial recording as required by SEC rules, both of which were partially offset by capital cost reductions. Additionally, these factors were largely offset by a non-cash impairment charge of approximately $1.5 billion recorded in the first quarter of 2016.

The increase in depreciation expense was primarily associated with additional other property and equipment related to buildings and other items.

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 calculate the expected 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, 2016, our estimates of commodity prices for purposes of determining undiscounted future cash flows are based on the NYMEX strip, which ranged from a 2016 price of $49.54 per barrel of oil and $3.04 per Mcf of natural gas to a 2023 price of $57.77 per barrel of oil and $3.50 per Mcf of natural gas. Commodity prices for this purpose were held flat after 2023.

We calculate the estimated 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 area 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. We did not recognize an impairment charge during the three months ended June 30, 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. If the oil and natural gas prices used in this analysis would have been approximately 10 percent lower as of June 30, 2016 with no other changes in capital costs, operating costs, price differentials, or reserve volumes, no impairment would be indicated.

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General and administrative expenses. The following table provides components of our general and administrative expenses for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,			
	2016		2015	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 91,151	$ 3.52	$ 101,517	$ 4.01
Non-cash stock-based compensation	28,473	1.10	30,945	1.22
Less: Third-party operating fee reimbursements	(12,472)	(0.48)	(12,738)	(0.50)
Total general and administrative expenses	$ 107,152	$ 4.14	$ 119,724	$ 4.73

General and administrative expenses were approximately $107.2 million ($4.14 per Boe) for the six months ended June 30, 2016, a decrease of $12.5 million (10 percent) from $119.7 million ($4.73 per Boe) for 2015. The decrease in cash general and administrative expenses was primarily a result of a general company-wide initiative to reduce general and administrative costs, while the decrease in non-cash stock-based compensation was primarily due to an increase in forfeiture estimates. The decrease in total general and administrative expenses per Boe was primarily due to the reduction in general and administrative costs noted above while there was a slight increase in production period over period.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $12.5 million and $12.7 million during the six months ended June 30, 2016 and 2015, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Gain (loss) on derivatives. The following table sets forth the gain (loss) on derivatives for the six months ended June 30, 2016 and 2015:

(in thousands)	Six Months Ended June 30, 2016		2015	
Gain (loss) on derivatives:				
Oil derivatives	$	(208,665)	$	(36,269)
Natural gas derivatives		(8,187)		4,210
Total	$	(216,852)	$	(32,059)

The following table represents our net cash receipts from derivatives for the six months ended June 30, 2016 and 2015:

(in thousands)	Six Months Ended June 30, 2016		2015	
Net cash receipts from derivatives:				
Oil derivatives	$	412,095	$	263,315
Natural gas derivatives		14,584		16,093
Total	$	426,679	$	279,408

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 future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Gain on disposition of assets, net. In February 2016, we sold certain assets in the northern Delaware Basin for proceeds of approximately $292.0 million, and recognized a pre-tax gain of approximately $110.1 million.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the six months ended June 30, 2016 and 2015:

(dollars in thousands)	Six Months Ended June 30, 2016	2015

Interest expense, as reported	$	108,640	$	107,051
Capitalized interest		252		2,389
Interest expense, excluding impact of capitalized interest	$	108,892	$	109,440
Weighted average interest rate - credit facility		-		2.6%
Weighted average interest rate - senior notes		5.9%		5.9%
Total weighted average interest rate		5.9%		5.8%
Weighted average credit facility balance	$	-	$	204,168
Weighted average senior notes balance		3,350,000		3,350,000
Total weighted average debt balance	$	3,350,000	$	3,554,168

The decrease in the weighted average debt balance for the six months ended June 30, 2016 as compared to 2015 was due to the repayment of our credit facility using a portion of the proceeds from our October 2015 equity offering. The increase in interest expense was due to a reduction in capitalized interest period over period, partially offset by an overall decrease in the weighted average debt balance.

Income tax provisions. We recorded an income tax benefit of $752.0 million and $66.6 million for the six months ended June 30, 2016 and 2015, respectively. The change in our income tax benefit was primarily due to the increase in our net loss before income taxes. The effective income tax rates for the six months ended June 30, 2016 and 2015 were 36.9 percent and 37.1 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 ventures 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 or 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 and asset retirement obligations, during the six months ended June 30, 2016 and 2015 totaled $525.6 million and $1.3 billion, respectively. The decrease was primarily due to our reduced drilling and completion activity level during the first half of 2016 as compared to the first half of 2015. The decrease is primarily related to our intent to adjust our capital spending to be within our cash flow, excluding unbudgeted acquisitions. The primary reason for the differences in the costs incurred and cash flow expenditures was our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition and timing of payments. The 2016 expenditures were primarily funded in part from (i) cash flows from operations, (ii) proceeds from our February 2016 divestiture and (iii) our issuance of approximately 2.2 million shares of common stock related to our March 2016 acquisition.

2016 capital budget. In November 2015, we announced our 2016 base capital budget, excluding acquisitions, of approximately $1.4 billion, with drilling and completion capital accounting for approximately $1.2 billion.

During the remainder of 2016, our intent is to manage our capital spending, as we did during the first half of 2016, to be within our cash flows. Based on current commodity prices and costs, our capital plan is in the range of $1.1 billion to $1.3 billion. However, if we were to outspend our cash flows, 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 and market conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans. Our 2016 capital program is expected to continue focusing on horizontal drilling across all our core areas.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
(in thousands)	**2016**	**2015**

Property acquisition costs:				
Proved	$	256,109	$	2,243
Unproved		157,407		34,050
Total property acquisition costs (a)	$	413,516	$	36,293

(a) Included in the property acquisition costs above are budgeted unproved leasehold acreage acquisitions of $23.3 million and $29.8 million for the six months ended June 30, 2016 and 2015, respectively. For the six months ended June 30, 2016, our unbudgeted acquisitions are primarily comprised of approximately $374.3 million of property acquisition costs related to our March 2016 unbudgeted acquisition.

Contractual obligations. Our contractual obligations include long-term debt, cash interest expense on debt, operating lease obligations, purchase obligations, employment agreements with officers, derivative liabilities, investment contributions related to Alpha Crude Connecter, LLC, our other midstream entity in the southern Delaware Basin and other obligations. Since December 31, 2015, the changes in our contractual obligations are not material. See Note 9 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, 2016.

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 and cash settlements received from derivatives, (ii) borrowings under our credit facility, (iii) proceeds from bond and equity offerings and (iv) proceeds from the sale of assets. During the remainder of 2016, our intent is to manage our capital spending, as we did during the first half of 2016, to be within our cash flows. Based on current commodity prices and costs, our capital plan is in the range of $1.1 billion to $1.3 billion. However, if we were to outspend our cash flows, we could use our (i) cash on hand, (ii) credit facility and (iii) other financing sources to fund any cash flow deficits.

The following table summarizes our changes in cash and cash equivalents for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,			
(in thousands)		**2016**		**2015**
Net cash provided by operating activities	$	249,825	$	488,934
Net cash provided by (used in) investing activities		14,836		(1,284,189)
Net cash provided by (used in) financing activities		(11,981)		795,514
Net increase in cash and cash equivalents	$	252,680	$	259

Cash flow from operating activities. The decrease in operating cash flows during the six months ended June 30, 2016 as compared to the same period in 2015 was primarily due to (i) a decrease in oil and natural gas revenues of approximately $271.1 million and (ii) approximately $64.8 million of negative variances in operating assets and liabilities, partially offset by (i) approximately $42.6 million decrease in cash production expense, (ii) an increase in operating cash flow of approximately $40.7 million due to a cash tax benefit of approximately $12.0 million for the six months ended June 30, 2016 compared to cash tax expense of approximately $28.7 million during 2015 and (iii) a cash decrease in general and administrative expense of approximately $10.1 million.

Our net cash provided by operating activities included a reduction of approximately $25.9 million and a benefit of approximately $38.9 million for the six months ended June 30, 2016 and 2015, 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 used in investing activities. During the six months ended June 30, 2016 and 2015, we invested approximately $0.7 billion and $1.5 billion, respectively, for capital expenditures on oil and natural gas properties. Additionally, we received approximately $294.3 million related to proceeds from the disposition of assets and approximately $426.7 million from settlements on derivatives during the six months ended June 30, 2016 as compared to $279.4 million from settlements on derivatives during the comparable period in 2015.

Cash flow from financing activities. Net cash used by financing activities was approximately $12.0 million for the six months ended June 30, 2016, while during 2015 we had net cash provided by financing activities of approximately $795.5 million. Below is a description of our significant financing activities:

- In March 2015, we issued shares of our common stock in a public offering and received net proceeds of approximately $741.5 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and the remainder for general corporate purposes.

- During the first six months of 2015, we had net borrowings on our credit facility of $66.5 million.

- During the first six months of 2016, we had no outstanding borrowings under our credit facility.

At June 30, 2016, we had unused commitments of approximately $2.5 billion based on bank commitments of $2.5 billion. The maturity date of the credit facility is May 9, 2019.

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") or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The credit facility's interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 125 to 225 basis points and 25 to 125 basis points, respectively, 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. Over the last three years, 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, 2016, we had approximately $481.2 million of cash on hand.

At June 30, 2016, our commitments from our bank group were $2.5 billion. We expect we will maintain our $2.5 billion in commitments until our next scheduled redetermination in May 2017. At June 30, 2016, our borrowing base was $2.8 billion. There is no assurance that our borrowing base will not be reduced, which could affect our liquidity. Upon a subsequent redetermination, our borrowing base could be substantially reduced.

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 Standard & Poor's Ratings Group, Inc. ("S&P") and Moody's Investors Service, Inc. ("Moody's"), which are subject to regular reviews. S&P's corporate rating for us is "BB+" with a stable outlook. Moody's corporate rating for us is "Ba1" with a stable outlook. 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, 2016; 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, 2016 was $8.7 billion, consisting of $0.5 billion of cash and cash equivalents, debt of $3.3 billion and stockholders' equity of $5.9 billion. Our net debt to book capitalization was 33 percent and 31 percent at June 30, 2016 and December 31, 2015, respectively. Our ratio of current assets to current liabilities was 1.93 to 1.0 at June 30, 2016 as compared to 2.20 to 1.0 at December 31, 2015.

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, 2016, we received an average of $35.80 per Bbl of oil and $1.70 per Mcf of natural gas before consideration of commodity derivative contracts compared to $47.99 per Bbl of oil and $2.65 per Mcf of natural gas in the six months ended June 30, 2015. 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 stock-based compensation, valuation of business combinations, valuation of financial derivative instruments 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, 2016. 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, 2015, filed with the United States Securities and Exchange Commission (the "SEC") on February 25, 2016.

Recent accounting pronouncements. In May 2014, the Financial Accounting Standards Board ("the FASB") issued Accounting Standards Update ("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.

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 2014-09 by one year. That new standard is now effective for annual reporting periods beginning after December 15, 2017. An entity can apply ASU 2014-09 using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. We are evaluating the impact that this new guidance will have on our 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 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 March 2016, the FASB issued ASU No. 2016-09, “Compensation–Stock Compensations (Topic 718): Improvements to Employee Share-based Payment Accounting,” which changes the accounting and presentation for share-based payment arrangements in the following areas: (i) recognition in the statement of operations of excess tax benefits and deficiencies; (ii) cash flow presentation of excess tax benefits and deficiencies; (iii) minimum statutory withholding thresholds and the classification on the cash flow statement of the withheld amounts; and (iv) an accounting policy election to recognize forfeitures as they occur. This guidance is effective for reporting periods beginning after December 15, 2016 and early adoption is permitted. We are evaluating the impact that this new guidance will have on our consolidated financial statements.

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, 2015.

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, 2016, 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. Although we have not generally required our counterparties to provide collateral to support their obligations to us, we may, if circumstances dictate, require collateral in the future. In this manner, we could reduce credit risk.

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 8 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, 2016:

(in thousands)		**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	$	(184,733)	$	184,733
Natural gas derivatives		(25,968)		25,968
Total	$	(210,701)	$	210,701

At June 30, 2016, we had (i) oil price swaps that settle on a monthly basis covering future oil production from July 1, 2016 through December 31, 2018 and (ii) oil basis swaps covering our Midland to Cushing basis differential from July 1, 2016 to December 31, 2017. The average NYMEX oil price for the six months ended June 30, 2016 was $39.65 per Bbl. At August 1, 2016, the NYMEX oil price was $40.06 per Bbl.

At June 30, 2016, we had natural gas price swaps that settle on a monthly basis covering future natural gas production from July 1, 2016 to December 31, 2017. The average NYMEX natural gas price for the six months ended June 30, 2016 was $2.12 per MMBtu. At August 1, 2016, the NYMEX natural gas price was $2.77 per MMBtu.

A decrease in the average forward NYMEX oil and natural gas prices below those at June 30, 2016 would increase the fair value asset of our commodity derivative contracts from their recorded balance at June 30, 2016. 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, 2016 would decrease the fair value asset of our commodity derivative contracts from their recorded balance at June 30, 2016. 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, 2016. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the six months ended June 30, 2016:

(in thousands)	**Commodity Derivative Instruments Net Assets (Liabilities) (a)**	
Fair value of contracts outstanding at December 31, 2015	$	819,536
Changes in fair values (b)		(216,852)
Contract maturities		(426,679)
Fair value of contracts outstanding at June 30, 2016	$	176,005

(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 8 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, 2016.

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, 2016 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 risk factor set forth below and the other 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, 2015, under the headings "Item 1. Business — Competition," "— Marketing Arrangements" and "— Applicable Laws and Regulatio "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," 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, 2015, other than updating the risk factor below. The risks described in our Annual Report on Form 10-K for the year ended December 31, 2015 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. The updated risk factor is as follows:

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in us having to make substantial downward adjustments to the value of our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. The primary factors that may affect management's estimates of future 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) cash flows from integrated assets and (v) results of future drilling activities. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

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, 2016 - April 30, 2016	114	$ 110.54	-	
May 1, 2016 - May 31, 2016	1,096	$ 115.18	-	
June 1, 2016 - June 30, 2016	17,558	$ 120.52	-	

(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			Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on November 8, 2012, 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		**	Employment Agreement dated May 17, 2016, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 19, 2016, 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 contract or 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, 2016	By	/s/ Timothy A. Leach
			Timothy A. Leach Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)
		By	/s/ Jack F. Harper
			Jack F. Harper Executive Vice President and Chief Financial Officer (Principal Financial Officer)
		By	/s/ Brenda R. Schroer
			Brenda R. Schroer Vice President, Chief Accounting Officer and Treasurer (Principal Accounting Officer)

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