Eclipse Resources Corp
Form 10-Q
August 03, 2017

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017

or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File Number: 001-36511

Eclipse Resources Corporation

(Exact name of registrant as specified in its charter)

Delaware	46-4812998
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2121 Old Gatesburg Rd, Suite 110	
State College, PA	16803
(Address of principal executive offices)	(Zip code)

(814) 308-9754

(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

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

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

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if a small reporting company)	Small reporting company
		Emerging growth company

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

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

Number of shares of the registrant's common stock outstanding at August 3, 2017: 262,738,442 shares

ECLIPSE RESOURCES CORPORATION

QUARTERLY REPORT ON FORM 10-Q

TABLE OF CONTENTS

Cautionary Statement Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q (the "Quarterly Report") contains "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this Quarterly Report, regarding our strategy, future operations, financial position, estimated revenues and income or losses, projected costs and capital expenditures, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report, the words "will," "plan," "would," "could," "endeavor," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looki statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are or were, when made, based on our current expectations and assumptions about future events and are or were, when made, based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in "Item 1A. Risk Factors" of our Annual Report on Form 10-K, filed with the Securities and Exchange Commission (the "SEC") on March 3, 2017.

Forward-looking statements may include statements about, among other things:

- realized prices for natural gas, natural gas liquids ("NGLs") and oil and the volatility of those prices;
- write-downs of our natural gas and oil asset values due to declines in commodity prices;
- our business strategy;
- our reserves, including the impact of current commodity prices on our estimated year end reserves;
- general economic conditions;
- our financial strategy, liquidity and capital required for developing our properties and the timing related thereto;
- the timing and amount of future production of natural gas, NGLs and oil;
- our hedging strategy and results;
- future drilling plans;
- competition and government regulations, including those related to hydraulic fracturing;
- the anticipated benefits under our commercial agreements;
- pending legal matters relating to our leases;
- marketing of natural gas, NGLs and oil;
- leasehold and business acquisitions;
- leasehold terms expiring before production can be established;
- the costs, terms and availability of gathering, processing, fractionation and other midstream services;
- credit markets;
- uncertainty regarding our future operating results, including initial production rates and liquid yields in our type curve areas; and
- plans, objectives, expectations and intentions contained in this Quarterly Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. These risks include, but are not limited to, legal and environmental risks, drilling and other operating risks, regulatory changes, commodity price volatility and the recent significant decline of the price of natural gas, NGLs and oil, inflation, lack of availability of drilling, production and processing equipment and services, inability to successfully negotiate or enter into definitive agreements regarding our proposed joint development transaction with Sequel Energy Group LLC, or to effectively implement that transaction, counterparty credit risk, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting future rates of production, cash flow and access to capital, risks associated with our level of indebtedness, the timing of development expenditures, and the other risks described in "Item 1A. Risk Factors" of our Annual Report on Form

10-K, filed with the SEC on March 3, 2017.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil 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 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 could change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Quarterly Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Quarterly Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect new information obtained or events or circumstances that occur after the date of this Quarterly Report.

PART I - FINANCIAL INFORMATION

Item 1. Financial Statements
ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

(Unaudited)

	June 30, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$97,075	$ 201,229
Accounts receivable	40,438	44,423
Assets held for sale	404	468
Other current assets	4,426	4,295
Total current assets	142,343	250,415
PROPERTY AND EQUIPMENT AT COST		
Oil and natural gas properties, successful efforts method:		
Unproved properties	492,058	526,270
Proved oil and gas properties, net	567,724	414,482
Other property and equipment, net	6,271	6,748
Total property and equipment, net	1,066,053	947,500
OTHER NONCURRENT ASSETS		
Other assets	3,861	729
TOTAL ASSETS	$1,212,257	$ 1,198,644
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$56,623	$ 44,049
Accrued capital expenditures	15,329	11,083
Accrued liabilities	20,174	55,044
Accrued interest payable	21,239	21,098
Liabilities held for sale	189	245
Total current liabilities	113,554	131,519
NONCURRENT LIABILITIES		
Debt, net of unamortized discount and debt issuance costs	493,644	492,278
Asset retirement obligations	5,598	4,806
Other liabilities	2,156	13,434
Total liabilities	614,952	642,037

COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY		
Preferred stock, 50,000,000 authorized, no shares issued and outstanding	—	—
Common stock, $0.01 par value, 1,000,000,000 authorized, 262,738,442 and 260,591,893 shares issued and outstanding, respectively	2,637	2,607
Additional paid in capital	1,963,090	1,958,731
Treasury stock, shares at cost; 991,247 and 72,704 shares, respectively	(2,093)	(61)
Accumulated deficit	(1,366,329)	(1,404,670)
Total stockholders' equity	597,305	556,607
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,212,257	$ 1,198,644

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

ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

(In thousands, except per share data)

(Unaudited)

	For the Three Months Ended		For the Six Months Ended	
	June 30, 2017	2016	June 30, 2017	2016
REVENUES				
Natural gas, oil and natural gas liquids sales	$86,194	$45,901	$185,625	$86,389
Brokered natural gas and marketing revenue	(3)	1,165	2,428	10,283
Total revenues	86,191	47,066	188,053	96,672
OPERATING EXPENSES				
Lease operating	4,568	2,248	6,911	4,925
Transportation, gathering and compression	28,969	28,254	61,846	51,391
Production and ad valorem taxes	2,033	2,203	3,964	4,766
Brokered natural gas and marketing expense	6	2,160	2,466	11,562
Depreciation, depletion and amortization	25,152	20,949	51,341	36,062
Exploration	8,997	17,444	20,577	33,100
General and administrative	10,730	10,402	20,862	21,676
Rig termination and standby	—	1,292	—	3,955
Impairment of proved oil and gas properties	—	—	—	17,665
Accretion of asset retirement obligations	128	89	252	175
(Gain) loss on sale of assets	6	(1,024)	1	(1,046)
Total operating expenses	80,589	84,017	168,220	184,231
OPERATING INCOME (LOSS)	5,602	(36,951)	19,833	(87,559)
OTHER INCOME (EXPENSE)				
Gain (loss) on derivative instruments	18,177	(29,596)	43,274	(19,046)
Interest expense, net	(12,285)	(12,439)	(24,747)	(25,900)
Gain (loss) on early extinguishment of debt	—	5,825	—	14,489
Other income (expense)	—	(2)	(19)	(141)
Total other expense, net	5,892	(36,212)	18,508	(30,598)
INCOME (LOSS) BEFORE INCOME TAXES	11,494	(73,163)	38,341	(118,157)
INCOME TAX BENEFIT (EXPENSE)	—	—	—	(540)
NET INCOME (LOSS)	$11,494	$(73,163)	$38,341	$(118,697)
NET INCOME (LOSS) PER COMMON SHARE				
Basic	$0.04	$(0.33)	$0.15	$(0.53)
Diluted	$0.04	$(0.33)	$0.15	$(0.53)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING				

Basic	262,423	223,013	261,768	222,898
Diluted	264,420	223,013	264,321	222,898

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

ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(In thousands, except share amounts)

(Unaudited)

	Number of Shares	Common Stock ($0.01 Par)	Additional Paid-in-Capital	Treasury Stock	Accumulated Deficit	Total
Balances, December 31, 2016	260,591,893	$ 2,607	$ 1,958,731	$ (61)	$ (1,404,670)	$ 556,607
Stock-based compensation	—	—	4,429	—	—	4,429
Equity issuance costs	—	—	(40)	—	—	(40)
Issuance of restricted stock	153,192	2	(2)	—	—	—
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings	1,993,357	28	(28)	(2,032)	—	(2,032)
Net income	—	—	—	—	38,341	38,341
Balances, June 30, 2017	262,738,442	$ 2,637	$ 1,963,090	$ (2,093)	$ (1,366,329)	$ 597,305

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

ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands)

(Unaudited)

	For the Six Months Ended June 30, 2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income (loss)	$38,341	$(118,697)
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities		
Depreciation, depletion and amortization	51,341	36,062
Exploration expense	9,192	18,722
Stock-based compensation	4,429	3,701
Impairment of proved oil and gas properties	—	17,665
Accretion of asset retirement obligations	252	175
(Gain) loss on derivative instruments	(43,274)	19,046
Net cash receipts (payments) on settled derivatives	(6,633)	31,258
(Gain) loss on sale of assets	1	(1,046)
(Gain) loss on early extinguishment of debt	—	(14,489)
Deferred income taxes	—	540
Amortization of deferred financing costs	1,035	972
Amortization of debt discount	661	691
Changes in operating assets and liabilities:		
Accounts receivable	3,992	(1,595)
Other assets	308	(2,586)
Accounts payable and accrued liabilities	5,796	(7,670)
Net cash provided by (used in) operating activities	65,441	(17,251)
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures for oil and gas properties	(166,012)	(42,913)
Capital expenditures for other property and equipment	(537)	(416)
Proceeds from sale of assets	544	14,094
Net cash used in investing activities	(166,005)	(29,235)
CASH FLOWS FROM FINANCING ACTIVITIES		
Debt issuance costs	(1,296)	261
Repayments of long-term debt	(222)	(23,786)
Equity issuance costs	(40)	(277)
Employee tax withholding for settlement of equity compensation awards	(2,032)	(61)
Net cash used in financing activities	(3,590)	(23,863)
Net decrease in cash and cash equivalents	(104,154)	(70,349)
Cash and cash equivalents at beginning of period	201,229	184,405

Cash and cash equivalents at end of period	$97,075	$114,056
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
Cash paid for interest	$23,502	$25,175
Cash paid for income taxes	$—	$—
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES		
Asset retirement obligations incurred, including changes in estimate	$540	$63
Additions to oil and natural gas properties - changes in accounts payable, accrued liabilities, and accrued capital expenditures	$11,674	$123

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

ECLIPSE RESOURCES CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1—Organization and Nature of Operations

Eclipse Resources Corporation (the "Company") is an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin of the United States, which encompasses the Utica Shale and Marcellus Shale prospective areas.

Note 2—Basis of Presentation

The accompanying condensed consolidated financial statements are unaudited except the condensed consolidated balance sheet at December 31, 2016, which is derived from the Company's audited financial statements, and are presented in accordance with the requirements of accounting principles generally accepted in the United States ("U.S. GAAP") for interim reporting. They do not include all disclosures normally made and contained in annual financial statements. In management's opinion, all adjustments necessary for a fair presentation of the Company's financial position, results of operations and cash flows for the periods disclosed have been made. All such adjustments are of a normal recurring nature. These interim condensed consolidated financial statements should be read in conjunction with the audited consolidated financial statements, and the notes to those statements, which are included in the Company's Annual Report on Form 10-K filed with the SEC on March 3, 2017.

Operating results for interim periods may not necessarily be indicative of the results of operations for the full year ending December 31, 2017 or any other future periods.

Preparation in accordance with U.S. GAAP requires the Company to (1) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board ("FASB") and (2) make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and other disclosed amounts. Note 3—Summary of Significant Accounting Policies describes our significant accounting policies. The Company's management believes the major estimates and assumptions impacting the condensed consolidated financial statements are the following:

- estimates of proved reserves of oil and natural gas, which affect the calculations of depreciation, depletion and amortization and impairment of capitalized costs of oil and natural gas properties;
- estimates of asset retirement obligations;
- estimates of the fair value of oil and natural gas properties the Company owns, particularly properties that the Company has not yet explored, or fully explored, by drilling and completing wells;
- impairment of undeveloped properties and other assets; and
- depreciation and depletion of property and equipment.

Actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions.

Note 3—Summary of Significant Accounting Policies

(a) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash in banks and highly liquid instruments with original maturities of three months or less, primarily consisting of bank time deposits and investments in institutional money market funds. The carrying amounts approximate fair value due to the short-term nature of these items. Cash in bank accounts at times may exceed federally insured limits.

(b) Accounts Receivable

Accounts receivable are carried at estimated net realizable value. Receivables deemed uncollectible are charged directly to expense. Trade credit is generally extended on a short-term basis, and therefore, accounts receivable do not bear interest, although a finance charge may be applied to such receivables that are past due. A valuation allowance is provided for those accounts for which collection is estimated as doubtful and uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the counterparty. The Company did not deem any of its accounts receivables to be uncollectible as of June 30, 2017 or December 31, 2016.

The Company accrues revenue due to timing differences between the delivery of natural gas, natural gas liquids (NGLs), and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Company’s records and management’s estimates of the related commodity sales and transportation and compression fees. The Company had $38.8 million and $41.4 million of accrued revenues, net of certain expenses, at June 30, 2017 and December 31, 2016, respectively, which were included in accounts receivable within the Company’s condensed consolidated balance sheets.

(c) Property and Equipment

Oil and Natural Gas Properties

The Company follows the successful efforts method of accounting for its oil and natural gas operations. Acquisition costs for oil and natural gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense (see “Depreciation, Depletion and Amortization” below).

Costs incurred to acquire producing and non-producing leaseholds are capitalized. All unproved leasehold acquisition costs are initially capitalized, including the cost of leasing agents, title work and due diligence. If the Company acquires leases in a prospective area, these costs are capitalized as unproved leasehold costs. If no leases are acquired by the Company with respect to the initial costs incurred or the Company discontinues leasing in a prospective area, the costs are charged to exploration expense. Unproved leasehold costs that are determined to have proved oil and gas reserves are transferred to proved leasehold costs.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Company’s condensed consolidated statements of operations. Upon the sale of an individual well, the proceeds are credited to accumulated depreciation and depletion within the Company’s condensed consolidated balance sheets. Upon sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Company’s condensed consolidated statements of operations. Upon sale of an entire interest in an unproved property where the property had been assessed for impairment on a group basis, no gain or loss is recognized in the Company’s consolidated statements of operations unless the proceeds exceed the original cost of the property, in which case a gain is recognized in the amount of such excess. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

A summary of property and equipment including oil and natural gas properties is as follows (in thousands):

	June 30, 2017	December 31, 2016
Oil and natural gas properties:		
Unproved	$492,058	$526,270
Proved	1,749,430	1,545,860
Gross oil and natural gas properties	2,241,488	2,072,130
Less accumulated depreciation depletion and amortization	(1,181,706)	(1,131,378)
Oil and natural gas properties, net	1,059,782	940,752
Other property and equipment	11,983	11,447
Less accumulated depreciation	(5,712)	(4,699)
Other property and equipment, net	6,271	6,748
Property and equipment, net	$1,066,053	$947,500

Exploration expenses, including geological and geophysical expenses and delay rentals for unevaluated oil and gas properties are charged to expense as incurred. Exploratory drilling costs are initially capitalized as unproved property, not subject to depletion, but charged to expense if and when the well is determined not to have found proved oil and gas reserves.

The Company capitalized interest expense totaling $0.5 million and $0.3 million for the three months ended June 30, 2017 and 2016, respectively. The Company capitalized interest expense totaling $0.9 million and $0.5 million for the six months ended June 30, 2017 and 2016, respectively.

Other Property and Equipment

Other property and equipment include land, buildings, leasehold improvements, vehicles, computer equipment and software, telecommunications equipment, and furniture and fixtures. These items are recorded at cost, or fair value if acquired through a business acquisition.

(d) Revenue Recognition

Oil and natural gas sales revenue is recognized when produced quantities of oil and natural gas are delivered to a custody transfer point such as a pipeline, processing facility or a tank lifting has occurred, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sales is reasonably assured and the sales price is fixed or determinable. Revenues from the sales of natural gas, crude oil and NGLs in which the Company has an interest with other producers are recognized using the sales method on the basis of the Company’s net revenue interest. The Company did not have any material imbalances as of June 30, 2017 or December 31, 2016.

In accordance with the terms of joint operating agreements, from time to time, the Company may be paid monthly fees for operating or drilling wells for outside owners. The fees are meant to recoup some of the operator’s general and administrative costs in connection with well and drilling operations and are accounted for as credits to general and administrative expense.

Brokered natural gas and marketing revenues include revenues from brokered gas or revenue the Company receives as a result of selling and buying natural gas that is not related to its production and revenue from the release of transportation capacity. The Company realizes brokered margins as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby the Company or the counterparty takes title to the natural gas purchased or sold. Revenues and expenses related to brokering natural gas are reported gross as part of revenue and expense in accordance with U.S. GAAP. The Company considers these activities as ancillary to its natural gas sales and thus, reports them within one operating segment.

(e) Concentration of Credit Risk

The Company’s principal exposures to credit risk are through the sale of its oil and natural gas production and related products and services, joint interest owner receivables and receivables resulting from commodity derivative contracts. The inability or failure of the Company’s significant customers or counterparties to meet their obligations or their insolvency or liquidation may adversely affect the Company’s financial results. The following table summarizes the Company’s concentration of receivables, net of allowances, by product or service as of June 30, 2017 and December 31, 2016 (in thousands):

	June 30, 2017	December 31, 2016
Receivables by product or service:		
Sale of oil and natural gas and related products		
and services	$38,829	$ 41,398
Joint interest owners	1,467	2,850
Derivatives	129	122
Other	13	53
Total	$40,438	$ 44,423

Oil and natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the State of Ohio. As a general policy, collateral is not required for receivables, but customers' financial condition and credit worthiness are evaluated regularly. By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, the Company exposes itself to the credit risk of counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, the Company's policy is to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. The fair value of the Company's unsettled commodity derivative contracts was a net liability position of ($2.3) million and ($48.1) million at June 30, 2017 and December 31, 2016, respectively. Other than as provided by its revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under the Company's contracts, nor are such counterparties required to provide credit support to the Company. As of June 30, 2017 and December 31, 2016, the Company did not have past-due receivables from or payables to any of such counterparties.

(f) Depreciation, Depletion and Amortization

Oil and Natural Gas Properties

Depreciation, depletion and amortization ("DD&A") of capitalized costs of proved oil and natural gas properties is computed using the unit-of-production method on a field level basis using total estimated proved reserves. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate DD&A for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves. DD&A expense relating to proved oil and natural gas properties totaled approximately $24.6 million and $20.4 million for the three months ended June 30, 2017 and 2016, respectively, and $50.3 million and $35.0 million for the six months ended June 30, 2017 and 2016, respectively.

Other Property and Equipment

Depreciation with respect to other property and equipment is calculated using straight-line methods based on expected lives of the individual assets or groups of assets ranging from 5 to 40 years. Depreciation totaled approximately $0.5 million for each of the three months ended June 30, 2017 and 2016 and $1.0 million for each of the six months ended June 30, 2017 and 2016. This amount is included in DD&A expense in the condensed consolidated statements of operations.

(g) Impairment of Long-Lived Assets

The Company reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The review for impairment of the Company's oil and gas properties is done by determining if the historical cost of proved and unproved properties less the applicable accumulated DD&A and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company's plans to continue to produce and develop proved reserves and a risk-adjusted portion of probable reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Company estimates prices based upon current contracts in place, adjusted for basis differentials and market-related information, including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. As a result of the decline in commodity prices, the Company recognized impairment expenses of approximately $17.7 million for the six months ended June 30, 2016 relating to proved properties in the Marcellus Shale. There were no impairments of proved properties for the three or six months ended June 30, 2017 or the three months ended June 30, 2016.

The aforementioned impairment charge represented a significant Level 3 measurement in the fair value hierarchy. The primary input used was the Company’s forecasted discount net cash flows.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results.

Unproved oil and natural gas properties are periodically assessed for impairment by considering future drilling and exploration plans, results of exploration activities, commodity price outlooks, planned future sales and expiration of all or a portion of the properties. An impairment charge is recorded if conditions indicate the Company will not explore the acreage prior to expiration of the applicable leases. The Company recorded impairment charges of unproved oil and gas properties related to lease expirations of approximately $4.1 million and $9.4 million for the three months ended June 30, 2017 and 2016, respectively, and approximately $8.3 million and $18.7 million for the six months ended June 30, 2017 and 2016, respectively. The decrease in impairment charges during the three and six months ended June 30, 2017 is the result of a decrease in expected lease expirations due to the increase in the Company’s planned future drilling activity. These costs are included in exploration expense in the condensed consolidated statements of operations.

(h) Income Taxes

The Company accounts for income taxes, as required, under the liability method as set out in the FASB’s Accounting Standards Codification (“ASC”) Topic 740 “Income Taxes.” Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

ASC Topic 740 further provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. Income tax positions must meet a more-likely-than-not recognition threshold at the effective date to be recognized upon the adoption of the uncertain tax position guidance and in subsequent periods. This interpretation also provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company has not recorded a reserve for any uncertain tax positions to date.

(i) Fair Value of Financial Instruments

The Company has established a hierarchy to measure its financial instruments at fair value which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1—Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2—Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3—Unobservable inputs that reflect the entity's own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

(j) Derivative Financial Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of the energy commodities it sells.

Derivatives are recorded at fair value and are included on the condensed consolidated balance sheets as current and noncurrent assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual expiration date. Derivatives with expiration dates within the next 12 months are classified as current. The Company netted the fair value of derivatives by counterparty in the accompanying condensed consolidated balance sheets where the right to offset exists. The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the condensed consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. Premiums for options are included in cash flows from operating activities.

The valuation of the Company's derivative financial instruments represents a Level 2 measurement in the fair value hierarchy.

(k) Asset Retirement Obligation

The Company recognizes a legal liability for its asset retirement obligations ("ARO") in accordance with ASC Topic 410, "Asset Retirement and Environmental Obligations," associated with the retirement of a tangible long-lived asset, in the period in which it is incurred or becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The Company measures the fair value of its ARO using expected future cash outflows for abandonment discounted back to the date that the abandonment obligation was measured using an estimated credit adjusted rate, which was 10.33% for each of the six months ended June 30, 2017 and 2016.

Estimating the future ARO requires management to make estimates and judgments based on historical estimates regarding timing and existence of a liability, as well as what constitutes adequate restoration, inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

The following table sets forth the changes in the Company's ARO liability for the six months ended June 30, 2017 (in thousands):

	Six Months Ended June 30, 2017
Asset retirement obligations, beginning of period	$ 4,806
Additional liabilities incurred	540
Accretion	252
Asset retirement obligations, end of period	$ 5,598

The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to ARO represent a significant nonrecurring Level 3 measurement.

(l) Lease Obligations

The Company leases office space under an operating lease that expires in 2024. The lease term begins on the date of initial possession of the leased property for purposes of recognizing lease expense on a straight-line basis over the term of the lease. The Company does not assume renewals in its determination of the lease term unless the renewals are deemed to be reasonably assured at lease inception.

(m) Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements.

(n) Segment Reporting

The Company operates in one industry segment: the oil and natural gas exploration and production industry in the United States. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

(o) Debt Issuance Costs

The expenditures related to issuing debt are capitalized and reported as a reduction of the Company's debt balance in the accompanying balance sheets. These costs are amortized over the expected life of the related instruments using the effective interest rate method. When debt is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed.

(p) Recent Accounting Pronouncements

The FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606) ("Update 2014-09")", which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, "Property, Plant and Equipment", and intangible assets within the scope of Topic 350, "Intangibles—Goodwill and Other") are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period with early adoption permitted.

The Company expects to adopt this standard effective January 1, 2018 using the modified retrospective method. As part of the implementation process, the Company has completed an analysis of the impact of the standard on its broad contracts and is currently reviewing all existing contracts. In addition, the Company continues to assess the impact of the new requirements on its internal systems and policies. Based on the contracts reviewed to date, the Company does not expect this standard to have a significant impact on its financial position or results of operations but will require that the Company's revenue recognition policy disclosures include further detail regarding its performance obligations as to the nature, amount, timing and estimates of revenue and cash flows generated from the Company's contracts with customers. The Company continues to monitor relevant industry guidance regarding implementation of the standard and adjust its implementation strategies as necessary.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." The new standard provides guidance to increase transparency and comparability among organizations and industries by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. An entity will be required to recognize all leases in the statement of financial position as assets and liabilities regardless of the leases classification. These requirements are effective for annual reporting periods beginning after December 15, 2018, including interim periods within that reporting period with early adoption permitted. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

In August 2016, the FASB issued ASU 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." The new standard provides guidance on how certain cash receipts and cash payments are presented and classified on the statement of cash flows. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period, with early adoption permitted. The Company is evaluating the impact of the adoption on its statement of cash flows and related disclosures.

In January 2017, the FASB issued ASU 2017-01, “Business Combinations (Topic 805): Clarifying the Definition of a Business.” Currently under the standard there are three elements of a business: inputs, processes and outputs. The revised guidance adds an initial screen test to determine if substantially all of the fair value of the gross assets acquired is concentrated in a single asset or group of similar assets. If that screen is met, the set of assets is not a business. The new framework also specifies the minimum required inputs and processes necessary to be a business. This amendment is effective for periods after December 15, 2017, with early adoption permitted. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

(q) Correction of Immaterial Error

During the three months ended March 31, 2017, the Company determined that its estimated accrual for production and ad valorem tax expense was overstated for prior periods. The Company evaluated the materiality of this error on both a quantitative and qualitative basis under the guidance of ASC 250 “Accounting Changes and Errors Corrections,” and determined that it did not have a material impact to previously issued financial statements.

Although the error was immaterial to prior periods, the prior period financial statements were revised, in accordance with SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, due to the significance of the out-of-period correction to the current period. Immaterial errors related to periods prior to the year ended December 31, 2016 are reflected as an adjustment to beginning accumulated deficit for that year. Periods not presented herein will be revised, as applicable, in future filings.

A reconciliation of the effects of the revision to amounts in the previously reported consolidated financial statements is as follows (in thousands, except per share amounts):

	As of December 31, 2016		
	As Reported	Adjustment	As Adjusted
Balance Sheet			
Accounts receivable	$43,638	$ 785	$44,423
Total current assets	249,630	785	250,415
Total assets	1,197,859	785	1,198,644
Accrued liabilities	64,150	(9,106)	55,044
Total current liabilities	140,625	(9,106)	131,519
Total liabilities	651,143	(9,106)	642,037
Accumulated deficit	(1,414,561)	9,891	(1,404,670)
Total stockholders' equity	546,716	9,891	556,607
Total liabilities and stockholders' equity	1,197,859	785	1,198,644

	As of December 31, 2016		
	As Reported	Adjustment	As Adjusted
Statement of Stockholders' Equity			
Accumulated deficit	$(1,414,561)	$ 9,891	$(1,404,670)
Total stockholders' equity	546,716	9,891	556,607

	Three Months Ended June 30, 2016		
	As Reported	Adjustment	As Adjusted
Statement of Operations and Comprehensive Income (Loss)			
Production and ad valorem taxes	$2,051	$ 152	$2,203
Total operating expenses	83,865	152	84,017
Operating loss	(36,799)	(152)	(36,951)
Loss before income taxes	(73,011)	(152)	(73,163)
Net loss	(73,011)	(152)	(73,163)
Basic and diluted loss per share	$(0.33)	$ —	$(0.33)

	Six Months Ended June 30, 2016		
	As Reported	Adjustment	As Adjusted
Statement of Operations and Comprehensive Income (Loss)			
Production and ad valorem taxes	$(233)	$ 4,999	$4,766
Total operating expenses	179,232	4,999	184,231
Operating loss	(82,560)	(4,999)	(87,559)
Loss before income taxes	(113,158)	(4,999)	(118,157)
Net loss	(113,698)	(4,999)	(118,697)
Basic and diluted loss per share	$(0.51)	$ (0.02)	$(0.53)

	As of June 30, 2016		
	As Reported	Adjustment	As Adjusted
Statement of Cash Flows			
Net loss	$(113,698)	$ (4,999)	$(118,697)
Accounts receivable	(1,238)	(357)	(1,595)
Accounts payable and accrued liabilities	(13,026)	5,356	(7,670)

Note 4—Sale of Oil and Natural Gas Property Interests

During the three and six months ended June 30, 2016, the Company completed the sale of its Conventional oil and gas properties and related equipment for approximately $4.7 million. As a result of this sale, the Company recognized a gain of approximately $1.0 million.

During the three and six months ended June 30, 2016, the Company received $3.9 million from the sale of mineral interests related primarily to unproved properties to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and natural gas properties.

During the six months ended June 30, 2016, the Company received $4.8 million from the sale of unproved leases to a third party. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and natural gas properties.

During the three and six months ended June 30, 2017, the Company received approximately $0.5 million from a completed asset sale with a third party totaling approximately 100 acres. No gain or loss was recognized for this transaction, which was recorded as a reduction of oil and natural gas properties.

Note 5—Derivative Instruments

Commodity Derivatives

The Company is exposed to market risk from changes in energy commodity prices within its operations. The Company utilizes derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas and oil. The Company currently uses a mix of over-the-counter (“OTC”) fixed price swaps, basis swaps and put options spreads and collars to manage its exposure to commodity price fluctuations. All of the Company’s derivative instruments are used for risk management purposes and none are held for trading or speculative purposes.

The Company is exposed to credit risk in the event of non-performance by counterparties. To mitigate this risk, the Company enters into derivative contracts only with counterparties that are rated “A” or higher by S&P or Moody’s. The creditworthiness of counterparties is subject to periodic review. As of June 30, 2017, the Company’s derivative instruments were with Bank of Montreal, Citibank, Goldman Sachs, Morgan Stanley, and Key Bank N.A. The Company has not experienced any issues of non-performance by derivative counterparties. Below is a summary of the Company’s derivative instrument positions, as of June 30, 2017, for future production periods:

Natural Gas Derivatives

Description	Volume (MMBtu/d)	Production Period	Weighted Average Price ($/MMBtu)
Natural Gas Swaps:			
	10,000	July 2017 – December 2017	$ 2.98
	10,000	July 2017 – December 2017	$ 3.21
	30,000	October 2017 – March 2018	$ 3.46
Natural Gas Three-way Collars:			
Floor purchase price (put)	160,000	July 2017 – December 2017	$ 2.83
Ceiling sold price (call)	160,000	July 2017 – December 2017	$ 3.37
Floor sold price (put)	160,000	July 2017 – December 2017	$ 2.31
Floor purchase price (put)	30,000	July 2017 – March 2019	$ 3.00
Ceiling sold price (call)	30,000	July 2017 – March 2019	$ 3.40
Floor sold price (put)	20,000	July 2017 – March 2019	$ 2.40
Floor sold price (put)	10,000	July 2017 – March 2019	$ 2.20
Floor purchase price (put)	20,000	October 2017 – December 2018	$ 2.90
Ceiling sold price (call)	20,000	October 2017 – December 2018	$ 3.50
Floor sold price (put)	20,000	October 2017 – December 2018	$ 2.20
Floor purchase price (put)	60,000	January 2018 – March 2018	$ 2.90
Ceiling sold price (call)	60,000	January 2018 – March 2018	$ 3.75
Floor sold price (put)	60,000	January 2018 – March 2018	$ 2.40
Floor purchase price (put)	60,000	April 2018 – December 2018	$ 2.90
Ceiling sold price (call)	60,000	April 2018 – December 2018	$ 3.25
Floor sold price (put)	60,000	April 2018 – December 2018	$ 2.40
Floor purchase price (put)	60,000	January 2018 – December 2018	$ 2.80
Ceiling sold price (call)	60,000	January 2018 – December 2018	$ 3.35
Floor sold price (put)	60,000	January 2018 – December 2018	$ 2.33
Floor purchase price (put)	20,000	July 2017 – December 2018	$ 2.90
Ceiling sold price (call)	20,000	July 2017 – December 2018	$ 3.25
Floor sold price (put)	20,000	July 2017 – December 2018	$ 2.40
Natural Gas Call/Put Options:			
Call sold	40,000	January 2018 – December 2018	$ 3.75
Call sold	10,000	January 2019 – December 2019	$ 4.75
Basis Swaps:			
TCO - Columbia	20,000	July 2017 – December 2017	$ (0.19)
Appalachia - Dominion	40,000	July 2017 – November 2017	$ (1.01)
Appalachia - Dominion	40,000	July 2017 – November 2017	$ (1.04)

Oil Derivatives

Description	Volume (Bbls/d)	Production Period	Weighted Average Price ($/Bbl)
Oil Three-way Collars:			
Floor purchase price (put)	2,000	July 2017 – September 2017	$ 46.00
Ceiling sold price (call)	2,000	July 2017 – September 2017	$ 59.50
Floor sold price (put)	2,000	July 2017 – September 2017	$ 38.00
Floor purchase price (put)	2,000	July 2017 – December 2017	$ 46.00
Ceiling sold price (call)	2,000	July 2017 – December 2017	$ 60.00
Floor sold price (put)	2,000	July 2017 – December 2017	$ 38.00

NGL Derivatives

Description	Volume (Gal/d)	Production Period	Weighted Average Price ($/Gal)
Propane Swaps:			
	84,000	July 2017 – December 2017	$ 0.60

Fair Values and Gains (Losses)

The following table summarizes the fair value of the Company’s derivative instruments on a gross basis and on a net basis as presented in the condensed consolidated balance sheets (in thousands). None of the derivative instruments are designated as hedges for accounting purposes.

As of June 30, 2017	Gross Amount	Netting Adjustments(a)	Net Amount Presented in Balance Sheets	Balance Sheet Location
Assets				
Commodity derivatives - current	$4,549	$ (4,110)	$ 439	Other current assets
Commodity derivatives - noncurrent	4,283	(2,115)	2,168	Other assets
Total assets	$8,832	$ (6,225)	$ 2,607	
Liabilities				
Commodity derivatives - current	$(7,349)	$ 4,110	$ (3,239)	Accrued liabilities
Commodity derivatives - noncurrent	(3,734)	2,115	(1,619)	Other liabilities
Total liabilities	$(11,083)	$ 6,225	$ (4,858)	

As of December 31, 2016	Gross Amount	Netting Adjustments(a)	Net Amount Presented in Balance Sheets	Balance Sheet Location
Assets				
Commodity derivatives - current	$50	$ (50)	$ —	

Commodity derivatives - noncurrent	—	—	—	
Total assets	$50	$ (50)	$—	
Liabilities				
Commodity derivatives - current	$(35,459)	$ 50	$(35,409)	Accrued liabilities
Commodity derivatives - noncurrent	(12,673)	—	(12,673)	Other liabilities
Total liabilities	$(48,132)	$ 50	$(48,082)	

(a) The Company has agreements in place that allow for the financial right to offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

The following table presents the Company's reported gains and losses on derivative instruments and where such values are recorded in the condensed consolidated statements of operations for the periods presented (in thousands):

		Amount of Gain (Loss) Recognized in Income			
Derivatives not designated as hedging	Location of Gain (Loss)	Three Months Ended		Six Months Ended	
instruments under ASC 815	Recognized in Income	June 30,		June 30,	
		2017	2016	2017	2016
Commodity derivatives	Gain (loss) on derivative instruments	$18,177	$(29,596)	$43,274	$(19,046)

Note 6—Fair Value Measurements

Fair Value Measurement on a Recurring Basis

The following table presents, by level within the fair value hierarchy, the Company's assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the condensed consolidated balance sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments. The fair value of the Company's derivatives is based on third-party pricing models which utilize inputs that are readily available in the public market, such as natural gas and crude oil forward curves. These values are compared to the values given by counterparties for reasonableness. Since the Company's derivative instruments do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2.

	Level 1	Level 2	Level 3	Total Fair Value
As of June 30, 2017: (in thousands)				
Commodity derivative instruments	$ —	$(2,251)	$ —	$ (2,251)
Total	$ —	$(2,251)	$ —	$ (2,251)
As of December 31, 2016: (in thousands)				
Commodity derivative instruments	$ —	$(48,082)	$ —	$ (48,082)
Total	$ —	$(48,082)	$ —	$ (48,082)

Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company's estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine the inception value of the Company's AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company's ARO represent a nonrecurring Level 3 measurement. (See Note 3—Summary of Significant Accounting Policies).

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. (See Note 3—Summary of Significant Accounting Policies).

The estimated fair values of the Company's financial instruments closely approximate the carrying amounts due, except for long-term debt. (See Note 7—Debt).

Note 7—Debt

8.875% Senior Unsecured Notes Due 2023

On July 6, 2015, the Company issued $550 million in aggregate principal amount of 8.875% senior unsecured notes due 2023 at an issue price of 97.903% of the principal amount of the notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the senior unsecured notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S under the Securities Act. Upon closing, the Company received proceeds of approximately $525.5 million, after deducting original issue discount, the initial purchasers' discounts and estimated offering expenses, of which the Company used approximately $510.7 million to finance the redemption of all of its outstanding Senior PIK Notes. The Company used the remaining net proceeds to fund its capital expenditure plan and for general corporate purposes. The fair value of the senior unsecured notes at June 30, 2017 was $508.1 million.

During the three and six months ended June 30, 2017, the Company amortized $0.8 million and $1.7 million, respectively, of deferred financing costs and debt discount to interest expense using the effective interest method. The Company amortized $0.8 million and $1.7 million of deferred financing costs and debt discount to interest expense using the effective interest method for the three and six months ended June 30, 2016, respectively.

The indenture governing the senior unsecured notes contains covenants that, among other things, limit the ability of the Company and its restricted subsidiaries to: (i) incur additional indebtedness, (ii) pay dividends on capital stock or redeem, repurchase or retire the Company's capital stock or subordinated indebtedness, (iii) transfer or sell assets, (iv) make investments, (v) create certain liens, (vi) enter into agreements that restrict dividends or other payments to the Company from its restricted subsidiaries, (vii) consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries, taken as a whole, (viii) engage in transactions with affiliates, and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the indenture. In addition, if the senior unsecured notes achieve an investment grade rating from either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services, and no default under the indenture has then occurred and is continuing, many of such covenants will be suspended. The indenture also contains events of default, which include, among others and subject in certain cases to grace and cure periods, nonpayment of principal or interest, failure by the Company to comply with its other obligations under the indenture, payment defaults and accelerations with respect to certain other indebtedness of the Company and its restricted subsidiaries, failure of any guarantee on the senior unsecured notes to be enforceable, and certain events of bankruptcy or insolvency. The Company was in compliance with all applicable covenants in the indenture at June 30, 2017.

During the six months ended June 30, 2016, the Company repurchased $39.5 million of the outstanding senior unsecured notes in open market purchases for $23.4 million. The principal of the outstanding senior unsecured notes that were repurchased less cash proceeds and unamortized debt discount and deferred financing costs were charged to gain on early extinguishment of debt, totaling $14.5 million for the six months ended June 30, 2016. The Company repurchased all such senior unsecured notes with cash on hand.

Revolving Credit Facility

During the first quarter of 2014, the Company entered into a $500 million senior secured revolving bank credit facility (the "revolving credit facility") that matures in 2018. Borrowings under the revolving credit facility are subject to borrowing base limitations based on the collateral value of the Company's proved properties and commodity hedge positions and are subject to semiannual redeterminations (April and October).

On February 24, 2016, the Company amended its revolving credit facility to, among other things, adjust the quarterly minimum interest coverage ratio, which is the ratio of EBITDAX to Cash Interest Expense, and to permit the sale of certain conventional properties. The amendment to the revolving credit facility increased the Applicable Margin (as defined in the Credit Agreement) applicable to loans and letter of credit participation fees under the Credit Agreement by 0.5% and required the Company to, within 60 days of the effectiveness of the amendment, execute and deliver additional mortgages on the Company's oil and gas properties that include at least 90% of its proved reserves.

On February 24, 2017, the borrowing base was redetermined, which increased the borrowing base from $125 million to $175 million, while extending the maturity of the credit facility to February 2020. In addition, the amendment modified the minimum interest coverage ratio covenant to a net leverage covenant of Net Debt to EBITDAX.

At June 30, 2017, the borrowing base was $175 million and the Company had no outstanding borrowings. After giving effect to outstanding letters of credit issued by the Company totaling $33.6 million, the Company had available borrowing capacity under the revolving credit facility of $141.4 million at June 30, 2017.

On August 1, 2017, the borrowing base was redetermined, which increased the borrowing base from $175 million to $225 million. The Company's next scheduled borrowing base redetermination is expected to be completed by April 2018.

The revolving credit facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's operating subsidiaries. The revolving credit facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company was in compliance with all applicable covenants under the revolving credit facility as of June 30, 2017. Commitment fees on the unused portion of the revolving credit facility are due quarterly at 0.5% of the unused facility based on utilization.

Note 8—Benefit Plans

Defined Contribution Plan

The Company currently maintains a retirement plan intended to provide benefits under section 401(K) of the Internal Revenue Code, under which employees are allowed to contribute portions of their compensation to a tax-qualified retirement account. Under the 401(K) plan, the Company provides matching contributions equal to 100% of the first 6% of employees' eligible compensation contributed to the plan. The Company recorded compensation expense related to matching contributions, classified under general and administrative, of \$0.2 million and \$0.1 million for the three months ended June 30, 2017 and 2016, respectively, and \$0.4 million for each of the six months ended June 30, 2017 and 2016.

Note 9—Stock-Based Compensation

The Company is authorized to grant up to 25,000,000 shares of common stock under its 2014 Long-Term Incentive Plan (as amended, the "Plan"). The Plan allows stock-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent rights, qualified performance-based awards and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of the Company's Board of Directors. A total of 10,345,434 shares were available for future grants under the Plan as of June 30, 2017.

Our stock-based compensation expense was as follows for the three and six months ended June 30, 2017 and 2016 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Restricted stock units	$ 1,344	$ 1,388	$2,591	$2,243
Performance units	907	677	1,641	1,057
Restricted stock issued to directors	97	142	197	353
Incentive units	—	19	—	48
Total expense	$ 2,348	$ 2,226	$4,429	$3,701

Restricted Stock Units

Restricted stock unit awards vest subject to the satisfaction of service requirements. The Company recognizes expense related to restricted stock and restricted stock unit awards on a straight-line basis over the requisite service period, which is three years. The grant date fair values of these awards are determined based on the closing price of the Company's common stock on the date of the grant. As of June 30, 2017, there was $8.5 million of total unrecognized compensation cost related to outstanding restricted stock units. The weighted average period for the shares to vest is approximately 1 year. A summary of restricted stock unit awards activity during the six months ended June 30, 2017 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2016	4,343,582	$ 2.14	$ 11,597
Granted	2,667,893	2.12	
Vested	(2,911,900)	1.65	
Forfeited	(47,812)	2.50	
Total awarded and unvested, June 30, 2017	4,051,763	$ 2.47	$ 11,588

Performance Units

Performance unit awards vest subject to the satisfaction of a three-year service requirement and based on Total Shareholder Return ("TSR"), as compared to an industry peer group over that same period. The performance unit awards are measured at the grant date at fair value using a Monte Carlo valuation method. As of June 30, 2017, there was $7.0 million of total unrecognized compensation cost related to outstanding performance units. The weighted average period for the shares to vest is approximately 2 years. A summary of performance stock unit awards activity during the six months ended June 30, 2017 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2016	1,928,002	$ 3.31	$ 5,148
Granted	2,564,523	1.94	
Vested	—	—	
Forfeited	(59,788)	3.04	
Total awarded and unvested, June 30, 2017	4,432,737	$ 2.52	$ 11,537

The determination of the fair value of the performance unit awards noted above uses significant Level 3 assumptions in the fair value hierarchy including an estimate of the timing of forfeitures, the risk free rate and a volatility estimate tied to the Company's public peer group.

Restricted Stock Issued to Directors

On May 11, 2015, the Company issued an aggregate of 132,496 restricted shares of common stock to its seven non-employee members of its Board of Directors, which became fully vested on May 11, 2016. For the three and six months ended June 30, 2016, the Company recognized expense of approximately $0.1 million and $0.3 million, respectively, related to these awards.

On May 18, 2016, the Company issued an aggregate of 149,448 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which became fully vested on May 18, 2017. For each of the three and six months ended June 30, 2016, the Company recognized expense of approximately $0.1

million related to these awards. For the three and six months ended June 30, 2017, the Company recognized expense of approximately $0.1 million and $0.2 million, respectively, related to these awards.

On May 17, 2017, the Company issued an aggregate of 153,192 restricted shares of common stock to its three non-employee members of its Board of Directors that are not affiliated with the Company's controlling stockholder, which are scheduled to fully vest on May 17, 2018. For each of the three and six months ended June 30, 2017, the Company recognized expense of approximately $0.1 million related to these awards. As of June 30, 2017, there was approximately $0.3 million of total unrecognized compensation cost related to outstanding restricted stock issued to the Company's directors.

Note 10—Equity

Public Offering of Common Stock

On June 28, 2016, the Company commenced an underwritten public offering of 37,500,000 shares of common stock, which was priced at $3.50 per share. The Company closed the offering on July 5, 2016 and received net proceeds of approximately $123 million (after deducting underwriting discounts and commissions and estimated expenses), which the Company used to fund its capital expenditure plan and for general corporate purposes.

Note 11—Earnings (Loss) Per Share

Earnings (Loss) Per Share

Basic earnings (loss) per share ("EPS") is computed by dividing net income (loss) by the weighted-average number of shares of common stock outstanding during the period. Diluted EPS takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with any stock awards that have been granted to directors and employees. In accordance with FASB ASC Topic 260, awards of non-vested shares shall be considered to be outstanding as of the grant date for purposes of computing diluted EPS even though their exercise is contingent upon vesting. During periods in which the Company incurs a net loss, diluted weighted-average shares outstanding are equal to basic weighted-average shares outstanding because the effect of all equity awards is antidilutive. The following is a calculation of the basic and diluted weighted-average number of shares of common stock and EPS for the three and six months ended June 30, 2017 and 2016, respectively:

	Three Months Ended June 30,					
(in thousands, except per share data)	2017			2016		
	Income	Shares	Per Share	(Loss)	Shares	Per Share
Basic:						
Net income (loss)	$11,494	262,423	$0.04	$(73,163)	223,013	$(0.33)
Weighted-average number of shares of common						

stock-diluted:						
Restricted stock and performance unit awards	—	1,997		—	—	
Diluted:						
Net income (loss)	$11,494	264,420	$0.04	$(73,163)	223,013	$(0.33)

(in thousands, except per share data)	Six Months Ended June 30, 2017			2016		
	Income	Shares	Per Share	(Loss)	Shares	Per Share
Basic:						
Net income (loss)	$38,341	261,768	$0.15	$(118,697)	222,898	$(0.53)
Weighted-average number of shares of common stock-diluted:						
Restricted stock and performance unit awards	—	2,553		—	—	
Diluted:						
Net income (loss)	$38,341	264,321	$0.15	$(118,697)	222,898	$(0.53)

Note 12—Related Party Transactions

During each of the three and six months ended June 30, 2017, the Company incurred approximately $0.2 million related to flight charter services provided by BWH Air, LLC and BWH Air II, LLC, which are owned by the Company's Chairman, President and Chief Executive Officer. The Company incurred approximately $0.1 million and $0.3 million related to such services during the three and six months ended June 30, 2016, respectively. The fees are paid in accordance with a standard service contract that does not obligate the Company to any minimum terms.

Note 13—Commitments and Contingencies

(a) Legal Matters

From time to time, the Company may be a party to legal proceedings arising in the ordinary course of business. Management does not believe that a material loss is probable as a result of such proceedings.

(b) Environmental Matters

The Company is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

(c) Leases

The development of the Company's oil and natural gas properties under their related leases will require a significant amount of capital. The timing of those expenditures will be determined by the lease provisions, the term of the lease and other factors associated with unproved leasehold acreage. To the extent that the Company is not the operator of oil and natural gas properties that it owns an interest in, the timing, and to some degree the amount, of capital expenditures will be controlled by the operator of such properties.

The Company leases office space under an operating lease that expires in 2024. The Company recognized rent expense of $0.2 million and $0.4 million for the three months ended June 30, 2017 and 2016, respectively, and $0.3 million and $0.6 million for the six months ended June 30, 2017 and 2016, respectively.

Note 14—Income Tax

For the year ending December 31, 2017, the Company's annual estimated effective tax rate is forecasted to be 0%, exclusive of discrete items. The Company recorded no income tax expense for the period due to a reduction of previously recorded valuation allowance in the amount of $13.4 million, which is net of a discrete item in the amount of $0.6 million related to an income tax for a share based compensation windfall settled in the first quarter of 2017.

The Company is forecasting positive pretax income for the year and as a result plans on reducing its valuation allowance to the extent the Company records pretax income cumulatively year to date in the quarter. At this time, the Company does not believe that the weight of evidence allows the release of its valuation allowance (due to a preponderance of negative evidence as to future realizability) and accordingly reflect a current deferred tax benefit of zero. The Company continues to evaluate the need for the valuation allowance based on current and expected earnings and other factors, and adjust it accordingly. No current federal income taxes are anticipated to be paid in the next twelve months. For the six months ended June 30, 2017, the Company's overall effective tax rate on operations was different than the federal statutory rate of 35% due primarily to valuation allowances and other permanent differences.

During the second quarter of 2017, the Internal Revenue Service completed its examination of Eclipse Resources Corporation for its tax year 2014. There were no adjustments to the Company's tax returns as a result of the examination.

Note 15—Subsidiary Guarantors

The Company's wholly-owned subsidiaries each have fully and unconditionally, joint and severally, guaranteed the Company's 8.875% senior unsecured notes (See Note 7—Debt). The Parent company has no independent assets or operations. The Company's wholly-owned subsidiaries are not restricted from transferring funds to the Parent or other wholly-owned subsidiaries. The Company's wholly-owned subsidiaries do not have any restricted net assets.

A subsidiary guarantor may be released from its obligations under the guarantee:

- in the event of a sale or other disposition of all or substantially all of the assets of the subsidiary guarantor or a sale or other disposition of all the capital stock of the subsidiary guarantor, to any corporation or other person by way of merger, consolidation, or otherwise; or
- if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the terms of the indenture governing the senior unsecured notes.

Note 16—Subsequent Events

Management has evaluated subsequent events and believes there are no events that would have a material impact on the aforementioned financial statements and related disclosures, other than those disclosed in the accompanying notes to the condensed consolidated financial statements (See Note 7—Debt).

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2016 and our condensed consolidated financial statements and related notes appearing elsewhere in this Quarterly Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. See "Cautionary Statement Regarding Forward-Looking Statements." We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Overview of Our Business

We are an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. As of June 30, 2017, we had assembled an acreage position approximating 206,000 net acres in Eastern Ohio, which excludes any acreage currently pending title.

Approximately 99,000 of our net acres are located in the Utica Shale fairway, which we refer to as the Utica Core Area, and approximately 15,000 of these net acres are also prospective for the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as our Marcellus Area. We are the operator of approximately 91% of our net acreage within the Utica Core Area and our Marcellus Area. We intend to focus on developing our substantial inventory of horizontal drilling locations during commodity price environments that will allow us to generate attractive returns and will continue to opportunistically add to this acreage position where we can acquire acreage at attractive prices.

As of June 30, 2017, we, or our operating partners, had commenced drilling 218 gross wells within the Utica Core Area and our Marcellus Area, of which 6 gross were top holed, 1 gross was drilling, 9 gross were awaiting completion or were in the process of being completed, 2 gross were awaiting midstream, and 200 gross had been turned to sales.

As of June 30, 2017, we were operating 2 horizontal rigs in the Utica Core Area. We had average daily production for the three months ended June 30, 2017 of approximately 287.8 MMcfe comprised of approximately 77% natural gas, 15% NGLs and 8% oil.

How We Evaluate Our Operations

In evaluating our current and future financial results, we focus on production and revenue growth, lease operating expense, general and administrative expense (both before and after non-cash stock compensation expense) and operating margin per unit of production. In addition to these metrics, we use Adjusted EBITDAX, a non-GAAP measure, to evaluate our financial results. We define Adjusted EBITDAX as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; depreciation, depletion and amortization ("DD&A"); amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments, and premiums (paid) received on options that settled during the period; non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX is not a measure of net income as determined by generally accepted accounting principles in United States, or "U.S. GAAP."

In addition to the operating metrics above, as we grow our reserve base, we will assess our capital spending by calculating our operated proved developed reserves and our operated proved developed finding costs and development costs. We believe that operated proved developed finding and development costs are one of the key measurements of the performance of an oil and gas exploration and production company. We will focus on our operated properties as we control the location, spending and operations associated with drilling these properties. In determining our proved developed finding and development costs, only cash costs incurred in connection with exploration and development will be used in the calculation, while the costs of acquisitions will be excluded because our board approves each material acquisition. In evaluating our proved developed reserve additions, any reserve revisions for changes in commodity prices between years will be excluded from the assessment, but any performance related reserve revisions are included.

We also continually evaluate our rates of return on invested capital in our wells. We believe the quality of our assets combined with our technical and managerial expertise can generate attractive rates of return as we develop our acreage in the Utica Core Area and our Marcellus Area. We review changes in drilling and completion costs; lease operating costs; natural gas, NGLs and oil prices; well productivity; and other factors in order to focus our drilling on the highest rate of return areas within our acreage.

Overview of Results for the Three and Six Months Ended June 30, 2017

During the three months ended June 30, 2017, we achieved the following financial and operating results:

- our average daily net production for the three months ended June 30, 2017 was 287.8 MMcfe per day representing an increase of 22% over the comparable period of the prior year;
- commenced drilling 9 gross (8.6 net) operated Utica and Marcellus Shale wells, completed 6 gross (5.8 net) operated Utica Shale wells and turned-to-sales 9 gross (9.0 net) operated Utica Shale wells;
- recognized net income of $11.5 million for the three months ended June 30, 2017 compared to a net loss of ($73.2) million for the three months ended June 30, 2016; and
- realized Adjusted EBITDAX of $39.6 million for the three months ended June 30, 2017 compared to $16.9 million for three months ended June 30, 2016. Adjusted EBITDAX is a non-GAAP financial measure. See "Non-GAAP Financial Measure" for more information.

During the six months ended June 30, 2017, we achieved the following financial and operating results:

- increased our average daily net production for the six months ended June 30, 2017 by 32% over the comparable period of the prior year, to 288.9 MMcfe per day;
- completed the drilling of two of our 19,500 foot extended reach lateral wells in less than 17 days to total depth;
- commenced drilling 13 gross (12.6 net) operated Utica and Marcellus Shale wells, completed 13 gross (12.8 net) operated Utica Shale wells and turned-to-sales 14 gross (13.7 net) operated Utica Shale wells;
- recognized net income of $38.3 million for the six months ended June 30, 2017 compared to a net loss of ($118.7) million for the six months ended June 30, 2016; and
- realized Adjusted EBITDAX of $89.8 million for the six months ended June 30, 2017 compared to $37.3 million for the six months ended June 30, 2016. Adjusted EBITDAX is a non-GAAP financial measure. See "Non-GAAP Financial Measure" for more information.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. The following table lists average, high, low and average monthly settled NYMEX Henry Hub prices for natural gas and NYMEX WTI prices for oil for the three and six months ended June 30, 2017 and 2016:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2017	2016	2017	2016
NYMEX Henry Hub High ($/MMBtu)	$ 3.27	$ 2.94	$ 3.71	$ 2.94
NYMEX Henry Hub Low ($/MMBtu)	2.85	1.71	2.44	1.49
Average Daily NYMEX Henry Hub ($/MMBtu)	3.08	2.16	3.05	2.09
Average Monthly NYMEX Settled Henry Hub ($/MMBtu)	3.18	1.95	3.25	2.02
NYMEX WTI High ($/Bbl)	$ 53.38	$ 51.23	$ 54.48	$ 51.23
NYMEX WTI Low ($/Bbl)	42.48	34.30	42.48	26.19
Average NYMEX WTI ($/Bbl)	48.10	46.21	49.85	40.88

Historically, commodity prices have been extremely volatile, and we expect this volatility to continue for the foreseeable future. A decline in commodity prices could materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. We make price assumptions that are used for planning purposes, and a significant portion of our cash outlays, including rent, salaries and noncancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

The Company is committed to profitably developing its natural gas, NGLs and condensate reserves through an environmentally responsible and cost-effective operational plan. The Company's revenues, earnings, liquidity and ability to grow are substantially dependent on the prices it receives for, and the Company's ability to develop its reserves. Despite the continued low price commodity environment, the Company believes the long-term outlook for its business is favorable due to the Company's resource base, low cost structure, risk management strategies, and disciplined investment of capital.

It is difficult to quantify the impact of changes in future commodity prices on our reported estimated net proved reserves with any degree of certainty because of the various components and assumptions used in the process. However, to demonstrate the sensitivity of our estimates of natural gas, NGLs and oil reserves to changes in commodity prices, we provided an analysis in our Annual Report on Form 10-K for the year ended December 31, 2016. Further, if we recalculated our reserves using the unweighted arithmetic average first-day-of-the-month price for each of the twelve months in the period ended June 30, 2017 and held all other factors constant, then then our estimated net proved reserves at December 31, 2016 would have increased by approximately 130% from our previously reported estimated net proved reserves at such time, including a 14% addition of proved developed reserves and a 332% addition of proved undeveloped reserves. The foregoing estimate is based upon an average SEC price of $3.01 per MMBtu for natural gas and $48.95 per Bbl for NGLs and oil. This calculation only isolates the potential impact of commodity prices on our estimated proved reserves and does not account for other factors impacting our estimated proved reserves, such as anticipated drilling and completion costs and our production results since December 31, 2016. There are also numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in subsequent periods. As such, this calculation is provided for illustrative purposes only and should not be construed as indicative of our final year-end reserve estimation process.

We consider future commodity prices when determining our development plan, but many other factors are also considered. To the extent there is a significant increase or decrease in commodity prices in the future, we will assess the impact on our development plan at that time, and we may respond to such changes by altering our capital budget or our development plan. We plan to fund our development budget with a portion of the cash on hand at June 30, 2017, cash flows from operations, borrowings under our revolving credit facility, proceeds from asset sales, and proceeds from additional debt and/or equity offerings.

Results of Operations

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

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

The following table illustrates the revenue attributable to our operations for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		
	2017	2016	Change
Revenues (in thousands)			
Natural gas sales	$ 59,890	$ 23,888	$ 36,002
NGL sales	11,151	9,331	1,820
Oil sales	15,153	12,682	2,471

Brokered natural gas and marketing revenue	(3)	1,165	(1,168)
Total revenues	$ 86,191	$ 47,066	$ 39,125

Our production grew by approximately 4.7 Bcfe for the three months ended June 30, 2017 over the same period in 2016 due to new wells that we placed into production. Our production for the three months ended June 30, 2017 and 2016 is set forth in the following table:

	Three Months Ended June 30, 2017	2016	Change
Production:			
Natural gas (MMcf)	20,127.8	15,298.5	4,829.3
NGL sales (Mbbls)	662.1	685.9	(23.8)
Oil sales (Mbbls)	347.8	345.2	2.6
Total (MMcfe)	26,187.2	21,485.1	4,702.1
Average daily production volume:			
Natural gas (Mcf/d)	221,185	168,115	53,070
NGL sales (Bbls/d)	7,276	7,537	(261)
Oil sales (Bbls/d)	3,822	3,793	29
Total (Mcfe/d)	287,771	236,095	51,676

During the second quarter of 2016, the Company was affected by revisions of prior estimates related to one of its non-operated partners that increased total net production by approximately 2.2 Bcfe, or 24 MMcfe per day, for the three months ended June 30, 2016.

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the three months ended June 30, 2017 was $2.84 per Mcfe compared to $2.42 per Mcfe during the three months ended June 30, 2016. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales price (excluding cash settled derivatives) does not include derivative settlements or third-party transportation costs which are reported in transportation, gathering and compression expense on the accompanying condensed consolidated statements of operations. Average sales price (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the three months ended June 30, 2017 and 2016 are shown below:

	Three Months Ended		
	June 30,		
	2017	2016	Change
Average Sales Price (excluding cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$ 2.98	$ 1.56	$ 1.42
NGLs ($/Bbl)	16.84	13.60	3.24
Oil ($/Bbl)	43.57	36.74	6.83
Total average prices ($/Mcfe)	3.29	2.14	1.15
Average Sales Price (including cash settled derivatives, excluding firm transportation)			
Natural gas ($/Mcf)	$ 2.86	$ 2.31	$ 0.55
NGLs ($/Bbl)	16.38	13.43	2.95
Oil ($/Bbl)	43.57	41.38	2.19
Total average prices ($/Mcfe)	3.19	2.74	0.45
Average Sales Price (including firm transportation, excluding cash settled derivatives)			
Natural gas ($/Mcf)	$ 2.52	$ 1.12	$ 1.40
NGLs ($/Bbl)	16.84	13.60	3.24
Oil ($/Bbl)	43.57	36.74	6.83
Total average prices ($/Mcfe)	2.94	1.82	1.12
Average Sales Price (including cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$ 2.41	$ 1.86	$ 0.55
NGLs ($/Bbl)	16.38	13.43	2.95
Oil ($/Bbl)	43.57	41.38	2.19
Total average prices ($/Mcfe)	2.84	2.42	0.42

During the second quarter of 2016, the Company was affected by revisions of prior estimates related to one of its non-operated partners that decreased natural gas realized prices by approximately $0.24 per Mcf and increased natural gas liquids prices by $0.61 per Bbl for the three months ended June 30, 2016.

Brokered natural gas and marketing revenue was less than ($0.1) million and $1.2 million for the three months ended June 30, 2017 and 2016, respectively. Brokered natural gas and marketing revenue includes revenue received from selling natural gas not related to production and from the release of firm transportation capacity. The decrease from the prior year period to the current year period was due to increased utilization of our firm transportation capacity for operated production during the three months ended June 30, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Costs and Expenses

We believe some of our expense fluctuations are most accurately analyzed on a unit-of-production, or per Mcfe, basis. The following table presents these expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30, 2017	2016	Change
Operating Expenses (in thousands):			
Lease operating	$ 4,568	$ 2,248	$ 2,320
Transportation, gathering and compression	28,969	28,254	715
Production and ad valorem taxes	2,033	2,203	(170)
Depreciation, depletion and amortization	25,152	20,949	4,203
General and administrative	10,730	10,402	328
Operating Expenses per Mcfe:			
Lease operating	$ 0.17	$ 0.10	$ 0.07
Transportation, gathering and compression	1.11	1.32	(0.21)
Production and ad valorem taxes	0.08	0.10	(0.02)
Depreciation, depletion and amortization	0.96	0.98	(0.02)
General and administrative	0.41	0.48	(0.07)

Lease operating expense was $4.6 million in the three months ended June 30, 2017 compared to $2.2 million in the three months ended June 30, 2016. Lease operating expense per Mcfe was $0.17 in the three months ended June 30, 2017 compared to $0.10 in the three months ended June 30, 2016. The increase of $2.3 million and $0.07 per Mcfe is attributable to an increase in the number of producing wells and non-recurring workover expenses during the three months ended June 30, 2017, as compared to the three months ended June 30, 2016. Lease operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs.

Transportation, gathering and compression expense was $29.0 million during the three months ended June 30, 2017 compared to $28.3 million in the three months ended June 30, 2016. Transportation, gathering and compression expense per Mcfe was $1.11 in the three months ended June 30, 2017 compared to $1.32 in the three months ended June 30, 2016. The following table details our transportation, gathering and compression expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30, 2017	2016	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	$ 11,165	$ 11,176	$ (11)
Processing and fractionation	7,444	8,320	(876)
Liquids transportation and stabilization	1,244	1,937	(693)
Marketing	6	6	—

Firm transportation	9,110	6,815	2,295
	$ 28,969	$ 28,254	$ 715
Transportation, gathering and compression per Mcfe:			
Gathering, compression and fuel	$ 0.43	$ 0.52	$ (0.09)
Processing and fractionation	0.28	0.39	(0.11)
Liquids transportation and stabilization	0.05	0.09	(0.04)
Marketing	—	0.00	—
Firm transportation	0.35	0.32	0.03
	$ 1.11	$ 1.32	$ (0.21)

The increase to expenses in the three months ended June 30, 2017 was due to our production growth and increased firm transportation expenses, which increased primarily due to additional capacity that came online during the fourth quarter of 2016. The decrease on a per unit basis was primarily related to increased production associated with natural gas and lower contractual rates.

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $2.0 million in the three months ended June 30, 2017 compared to $2.2 million in the three months ended June 30, 2016. Production and ad valorem taxes per Mcfe was $0.08 in the three months ended June 30, 2017 compared to $0.10 in the three months ended June 30, 2016. The decrease in production and ad valorem taxes on both a total and per unit basis is due to the lower taxable value rate for the three months ended June 30, 2017.

Depreciation, depletion and amortization was approximately $25.2 million in the three months ended June 30, 2017 compared to $20.9 million in the three months ended June 30, 2016. The increase in the three months ended June 30, 2017 when compared to the three months ended June 30, 2016 is due to the increase in production for the three months ended June 30, 2017. On a per Mcfe basis, DD&A decreased to $0.96 in the three months ended June 30, 2017 from $0.98 in the three months ended June 30, 2016, which was predominantly driven by the lower depletion rate resulting from our increased reserves for the three months ended June 30, 2017.

General and administrative expense was $10.7 million for the three months ended June 30, 2017 compared to $10.4 million for the three months ended June 30, 2016. General and administrative expense per Mcfe was $0.41 in the three months ended June 30, 2017 compared to $0.48 in the three months ended June 30, 2016. The increase of $0.3 million during the three months ended June 30, 2017 when compared to three months ended June 30, 2016 was primarily due to higher salaries and benefits associated with increased headcount for the three months ended June 30, 2017. The decrease of $0.07 per Mcfe is due to fixed costs being spread across higher production as of June 30, 2017 as compared to June 30, 2016.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. The following table details our other operating expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended		
	June 30, 2017	2016	Change
Other Operating Expenses (in thousands):			
Brokered natural gas and marketing expense	$ 6	$ 2,160	$ (2,154)
Exploration	8,997	17,444	(8,447)
Rig termination and standby	—	1,292	(1,292)
Accretion of asset retirement obligations	128	89	39
(Gain) loss on sale of assets	6	(1,024)	1,030

Brokered natural gas and marketing expense was less than $0.1 million for the three months ended June 30, 2017 compared to $2.2 million for the three months ended June 30, 2016. Brokered natural gas and marketing expenses relate to gas purchases that we buy and sell not relating to production and firm transportation capacity that is marketed to third parties. The decrease from the prior year period to the current year period was due to increased utilization of our firm transportation capacity for operated production during the three months ended June 30, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Exploration expense was $9.0 million for the three months ended June 30, 2017 compared to $17.4 million for the three months ended June 30, 2016. The following table details our exploration-related expenses for the three months ended June 30, 2017 and 2016:

	Three Months Ended June 30, 2017	2016	Change
Exploration Expenses (in thousands):			
Geological and geophysical	$ 364	$ 395	$ (31)
Delay rentals	4,429	7,178	(2,749)
Impairment of unproved properties	4,125	9,360	(5,235)
Dry hole and other	79	511	(432)
	$ 8,997	$ 17,444	$ (8,447)

Delay rentals were $4.4 million for the three months ended June 30, 2017 compared to $7.2 million for the three months ended June 30, 2016. The decrease in delay rental expenses relates to the reduction of converting future lump-sum extension payments into annual delay rentals during the current year period.

Impairment of unproved properties was $4.1 million for the three months ended June 30, 2017 compared to $9.4 million for the three months ended June 30, 2016. The decrease in impairment charges during the three months ended June 30, 2017 is the result of a decrease in expected lease expirations due to the increase in our planned future drilling activity. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

Rig termination and standby expense for the three months ended June 30, 2016 were $1.3 million related primarily to standby costs that we incurred from temporarily suspending our drilling operations for a portion of such period. There were no rig termination and standby expenses for the three months ended June 30, 2017.

Accretion of asset retirement obligations was $0.1 million for the three months ended June 30, 2017 compared to $0.1 million for three months ended June 30, 2016. The accretion expense primarily relates to the asset retirement obligations associated with the number of producing wells.

Other Income (Expense)

Gain (loss) on derivative instruments was $18.2 million for the three months ended June 30, 2017 compared to ($29.6) million for the three months ended June 30, 2016, driven by changes in commodity prices during each year. Cash payments were approximately $2.6 million and cash receipts were approximately $12.9 million for derivative instruments that settled during the three months ended June 30, 2017 and June 30, 2016, respectively.

Interest expense, net was $12.3 million for the three months ended June 30, 2017 compared to $12.4 million for three months ended June 30, 2016. Interest expense primarily relates to our senior unsecured notes and was relatively consistent during such periods.

Gain on early extinguishment of debt was $5.8 million for the three months ended June 30, 2016 resulting from the repurchase of $21.0 million of our outstanding senior unsecured notes on the open market for $14.3 million with cash on hand. The outstanding senior unsecured notes principal repurchased less cash proceeds and unamortized debt discount and deferred financing costs of $0.8 million were charged to gain on early extinguishment of debt. No gain or loss on early extinguishment of debt was recognized for the three months ended June 30, 2017.

Income tax benefit (expense) was not recognized for the three months ended June 30, 2017 and 2016 due to the Company reducing the valuation allowance to the extent of the tax effect of recorded pre-tax income and recording valuation allowance due to recurring pre-tax losses, respectively.

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

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

The following table illustrates the revenue attributable to our operations for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30, 2017	2016	Change
Revenues (in thousands)			

Natural gas sales	$121,310	$51,929	$69,381
NGL sales	28,213	15,853	12,360
Oil sales	36,102	18,607	17,495
Brokered natural gas and marketing revenue	2,428	10,283	(7,855)
Total revenues	$188,053	$96,672	$91,381

Our production grew by approximately 12.5 Bcfe for the six months ended June 30, 2017 over the same period in 2016 as we placed new wells into production. Our production for the six months ended June 30, 2017 and 2016 is set forth in the following table:

	Six Months Ended June 30,		
	2017	2016	Change
Production:			
Natural gas (MMcf)	39,509.4	28,985.8	10,523.6
NGL sales (Mbbls)	1,327.1	1,199.6	127.5
Oil sales (Mbbls)	801.9	600.5	201.4
Total (MMcfe)	52,283.4	39,786.4	12,497.0
Average daily production volume:			
Natural gas (Mcf/d)	218,284	159,263	59,021
NGL sales (Bbls/d)	7,332	6,591	741
Oil sales (Bbls/d)	4,430	3,299	1,131
Total (Mcfe/d)	288,859	218,603	70,256

During the six months ended June 30, 2016, the Company was affected by revisions of prior estimates related to one of its non-operated partners that increased total net production by approximately 2.2 Bcfe, or 12 MMcfe per day, for such period.

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the six months ended June 30, 2017 was $3.04 per Mcfe compared to $2.63 per Mcfe during the six months ended June 30, 2016. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales price (excluding cash settled derivatives) does not include derivative settlements or third-party transportation costs which are reported in transportation, gathering and compression expense on the accompanying condensed consolidated statements of operations. Average sales price (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the six months ended June 30, 2017 and 2016 are shown below:

	Six Months Ended June 30,		
	2017	2016	Change
Average Sales Price (excluding cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$3.07	$1.79	$1.28
NGLs ($/Bbl)	21.26	13.22	8.04
Oil ($/Bbl)	45.02	30.99	14.03
Total average prices ($/Mcfe)	3.55	2.17	1.38
Average Sales Price (including cash settled derivatives, excluding firm transportation)			
Natural gas ($/Mcf)	$2.94	$2.60	$0.34
NGLs ($/Bbl)	20.23	13.43	6.80
Oil ($/Bbl)	45.11	43.52	1.59
Total average prices ($/Mcfe)	3.42	2.96	0.46
Average Sales Price (including firm transportation, excluding cash settled derivatives)			
Natural gas ($/Mcf)	$2.56	$1.35	$1.21
NGLs ($/Bbl)	21.26	13.22	8.04
Oil ($/Bbl)	45.02	30.99	14.03
Total average prices ($/Mcfe)	3.16	1.85	1.31
Average Sales Price (including cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$2.43	$2.16	$0.27
NGLs ($/Bbl)	20.23	13.43	6.80
Oil ($/Bbl)	45.11	43.52	1.59

Total average prices ($/Mcfe)	3.04	2.63	0.41

During the six months ended June 30, 2016, the Company was affected by revisions of prior estimates related to one of its non-operated partners that decreased natural gas realized prices by approximately $0.13 per Mcf and increased NGL prices by $0.37 per Bbl for such period.

Brokered natural gas and marketing revenue was $2.4 million and $10.3 million for the six months ended June 30, 2017 and 2016, respectively. Brokered natural gas and marketing revenue includes revenue received from selling natural gas not related to production and from the release of firm transportation capacity. The decrease from the prior year period to the current year period was due to increased utilization of our firm transportation capacity for operated production during the six months ended June 30, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Costs and Expenses

We believe some of our expense fluctuations are most accurately analyzed on a unit-of-production, or per Mcfe, basis. The following table presents these expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended		
	June 30,		
	2017	2016	Change
Operating Expenses (in thousands)			
Lease operating	$6,911	$4,925	$1,986
Transportation, gathering and compression	61,846	51,391	10,455
Production and ad valorem taxes	3,964	4,766	(802)
Depreciation, depletion and amortization	51,341	36,062	15,279
General and administrative	20,862	21,676	(814)
Operating Expenses per Mcfe:			
Lease operating	$0.13	$0.12	$0.01
Transportation, gathering and compression	1.19	1.29	(0.10)
Production and ad valorem taxes	0.08	0.12	(0.04)
Depreciation, depletion and amortization	0.98	0.91	0.07
General and administrative	0.40	0.54	(0.14)

Lease operating expense was $6.9 million in the six months ended June 30, 2017 compared to $4.9 million in the six months ended June 30, 2016. Lease operating expense per Mcfe was $0.13 in the six months ended June 30, 2017 compared to $0.12 in the six months ended June 30, 2016. The increase of $2.0 million and $0.01 per Mcfe is attributable to an increase in the number of producing wells as well as workover expenses during the six months ended June 30, 2017, as compared to the six months ended June 30, 2016. Lease operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties.

Transportation, gathering and compression expense was $61.8 million during the six months ended June 30, 2017 compared to $51.4 million in the six months ended June 30, 2016. Transportation, gathering and compression expense per Mcfe was $1.19 in the six months ended June 30, 2017 compared to $1.29 in the six months ended June 30, 2016. The following table details our transportation, gathering and compression expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended		
	June 30,		
	2017	2016	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	$21,912	$19,312	$2,600
Processing and fractionation	15,761	15,862	(101)
Liquids transportation and stabilization	4,006	3,338	668

Marketing	18	—	18
Firm transportation	20,149	12,879	7,270
	$61,846	$51,391	$10,455
Transportation, gathering and compression per Mcfe:			
Gathering, compression and fuel	$0.42	$0.49	$(0.07)
Processing and fractionation	0.30	0.40	(0.10)
Liquids transportation and stabilization	0.08	0.08	—
Marketing	—	—	—
Firm transportation	0.39	0.32	0.07
	$1.19	$1.29	$(0.10)

The increase to expenses in the six months ended June 30, 2017 was due to our production growth and increased firm transportation expenses, which increased primarily due to additional capacity that came online during the fourth quarter of 2016. The decrease on a per unit basis was primarily related to our increased production and updated third party contracts.

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $4.0 million in the six months ended June 30, 2017 compared to $4.8 million in the six months ended June 30, 2016. Production and ad valorem taxes per Mcfe was $0.08 in the six months ended June 30, 2017 compared to $0.12 in the six months ended June 30, 2016. The decrease in production and ad valorem taxes on both a total and per unit basis is due to the lower taxable value rate for the six months ended June 30, 2017.

Depreciation, depletion and amortization was approximately $51.3 million in the six months ended June 30, 2017 compared to $36.1 million in the six months ended June 30, 2016. The increase in the six months ended June 30, 2017 when compared to the six months ended June 30, 2016 is due to the increase in production and proved property costs during the six months ended June 30, 2017. On a per Mcfe basis, DD&A increased to $0.98 in the six months ended June 30, 2017 from $0.91 in the six months ended June 30, 2016, which was predominantly driven by the higher depletion rate resulting from our increased proved property costs during the six months ended June 30, 2017.

General and administrative expense was $20.9 million for the six months ended June 30, 2017 compared to $21.7 million for the six months ended June 30, 2016. General and administrative expense per Mcfe was $0.40 in the six months ended June 30, 2017 compared to $0.54 in the six months ended June 30, 2016. The decrease of $0.8 million and $0.14 per Mcfe during the six months ended June 30, 2017 when compared to six months ended June 30, 2016 was due to lower professional fees incurred and fixed costs spread across increased production as of June 30, 2017 as compared to June 30, 2016, respectively.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. The following table details our other operating expenses for the six months ended June 30, 2017 and 2016:

	Six Months Ended June 30,		
	2017	2016	Change
Other Operating Expenses (in thousands):			
Brokered natural gas and marketing expense	$2,466	$11,562	$(9,096)
Exploration	20,577	33,100	(12,523)
Rig termination and standby	—	3,955	(3,955)
Impairment of proved oil and natural gas properties	—	17,665	(17,665)
Accretion of asset retirement obligations	252	175	77
(Gain) loss on sale of assets	1	(1,046)	1,047

Brokered natural gas and marketing expense was $2.5 million for the six months ended June 30, 2017 compared to $11.6 million for the six months ended June 30, 2016. Brokered natural gas and marketing expenses relate to gas purchases that we buy and sell not relating to production and firm transportation capacity that is marketed to third parties. The decrease from the prior year period to the current year period was due to increased utilization of our firm transport capacity for operated production during the six months ended June 30, 2017, which resulted in a decrease in the amount of firm transportation that was available for brokered gas transactions or release to third parties.

Exploration expense was $20.6 million for the six months ended June 30, 2017 compared to $33.1 million for the six months ended June 30, 2016. The following table details our exploration-related expenses for the six months ended

June 30, 2017 and 2016:

	Six Months Ended		
	June 30,		
	2017	2016	Change
Exploration Expenses (in thousands):			
Geological and geophysical	$779	$415	$364
Delay rentals	10,606	13,417	(2,811)
Impairment of unproved properties	8,250	18,720	(10,470)
Dry hole and other	942	548	394
	$20,577	$33,100	$(12,523)

Delay rentals were $10.6 million for the six months ended June 30, 2017 compared to $13.4 million for the six months ended June 30, 2016. The decrease in delay rental expenses relates to the reduction of converting future lump-sum extension payments into annual delay rentals during the current year period.

Impairment of unproved properties was $8.3 million for the six months ended June 30, 2017 compared to $18.7 million for the six months ended June 30, 2016. The decrease in impairment charges during the six months ended June 30, 2017 is the result of a decrease in expected lease expirations due to the increase in our planned future drilling activity. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

Rig termination and standby expense for the six months ended June 30, 2016 were $4.0 million related primarily to standby costs that we incurred from temporarily suspending our drilling operations for a portion of such period. There were no rig termination and standby expenses for the six months ended June 30, 2017.

Impairment of proved oil and gas properties was $17.7 million for the six months ended June 30, 2016. There was no impairment of proved oil and gas properties recognized for the six months ended June 30, 2017.

Accretion of asset retirement obligations was $0.3 million for the six months ended June 30, 2017 compared to $0.2 million for six months ended June 30, 2016. The accretion expense primarily relates to the asset retirement obligations associated with the number of producing wells.

Other Income (Expense)

Gain (loss) on derivative instruments was $43.3 million for the six months ended June 30, 2017 compared to ($19.0) million for the six months ended June 30, 2016, driven by changes in commodity prices during each year. Cash payments were approximately $6.6 million and cash receipts were approximately $31.3 million for derivative instruments that settled during the six months ended June 30, 2017 and June 30, 2016, respectively.

Interest expense, net was $24.7 million for the six months ended June 30, 2017 compared to $25.9 million for six months ended June 30, 2016. The decrease in interest expense was primarily due to the early extinguishment of debt during the first half of 2016.

Gain on early extinguishment of debt was $14.5 million for the six months ended June 30, 2016 resulting from the repurchase of $39.5 million of our outstanding senior unsecured notes on the open market for $23.4 million during such period. The outstanding senior unsecured notes principal repurchased less cash proceeds and unamortized debt discount and deferred financing costs of $1.6 million were charged to gain on early extinguishment of debt. No gain or loss on early extinguishment of debt was recognized for the six months ended June 30, 2017.

Income tax benefit (expense) was ($0.5) million for the six months ended June 30, 2016 related to the write-off of certain state deferred tax assets. No income tax expense was recorded for the six months ended June 30, 2017 due to the Company reducing the valuation allowance to the extent of the tax effect of recorded pre-tax income.

Cash Flows, Capital Resources and Liquidity

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices. Our cash flows from operations also are impacted by changes in working capital. Short-term liquidity needs are satisfied by our operating cash flow, proceeds from asset sales, borrowings under our revolving credit facility and proceeds from issuances of debt and equity securities.

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

Net cash provided by (used in) operations in the six months ended June 30, 2017 was $65.4 million compared to ($17.3) million in the six months ended June 30, 2016. The increase in cash provided from operating activities reflects the increase in commodity prices over year-over-year comparative periods, working capital changes, and the timing of cash receipts and disbursements.

Net cash used in investing activities in the six months ended June 30, 2017 was $166.0 million compared to $29.2 million in the six months ended June 30, 2016.

During the six months ended June 30, 2017, we:

- spent $166.0 million on capital expenditures for oil and natural gas properties;
- spent $0.5 million on property and equipment; and
- received $0.5 million of proceeds relating to the sale of assets.

During the six months ended June 30, 2016, we:

- spent $42.9 million on capital expenditures for oil and gas properties;
- spent $0.4 million on property and equipment; and
- received $14.1 million of proceeds relating to the sale of assets.

Net cash used in financing activities in the six months ended June 30, 2017 was $3.6 million compared to $23.9 million in the six months ended June 30, 2016.

During the six months ended June 30, 2017, we:

- paid $1.3 million in financing costs associated with our amendment that increased our borrowing base capacity on our revolving credit facility;
- paid $2.0 million to repurchase stock in relation to tax withholding for settlement of equity compensation awards.

During the six months ended June 30, 2016, we:

- purchased outstanding senior unsecured notes with aggregate principal amount of $39.5 million for $23.4 million.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, asset sales, borrowings under our revolving credit facility and access to the debt and equity capital markets. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which require substantial capital expenditures. We periodically review capital expenditures and adjust our budget based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices. We believe that our existing cash on hand, operating cash flow and available borrowings under our revolving credit facility will be adequate to meet our capital and operating requirements for 2017.

Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We will continue using net cash on hand, cash flows from operations, and borrowings under our revolving credit facility to satisfy near-term financial obligations and liquidity needs, and as necessary, we will seek additional sources of debt or equity to fund these requirements. Longer-term cash flows are subject to a number of variables including the level of production and prices we receive for our production as well as various economic conditions that have historically affected the natural gas and oil business. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

As of June 30, 2017, we were in compliance with all of our debt covenants under the credit agreement governing our revolving credit facility and the indenture governing our 8.875% senior unsecured notes due 2023. Further, based on our current forecast and activity levels, we expect to remain in compliance with all such debt covenants for the next twelve months. However, if oil and natural gas prices decrease to lower levels, we are likely to generate lower operating cash flows, which would make it more difficult for us to remain in compliance with all of our debt covenants, including requirements with respect to working capital and interest coverage ratios. This could negatively impact our ability to maintain sufficient liquidity and access to capital resources.

Credit Arrangements

Long-term debt at June 30, 2017 and December 31, 2016, excluding discount, totaled $510.5 million. (See Note 7—Debt).

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior unsecured notes due 2023 at an issue price of 97.903% of the principal amount of the notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the senior unsecured notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S under the Securities Act. Upon closing, we received proceeds of approximately $525.5 million, after deducting original issue discount, the initial purchasers' discounts and estimated offering expenses, of which we used approximately $510.7 million to finance the redemption of all of our outstanding 12.0% Senior PIK notes due 2018. We used the remaining net proceeds to fund our capital expenditure plan and for general corporate purposes. (See Note 7—Debt).

During the six months ended June 30, 2016, the Company repurchased $39.5 million of the outstanding senior unsecured notes in open market purchases for $23.4 million. The outstanding principal of the senior unsecured notes that were repurchased less cash proceeds and unamortized debt discount and deferred financing costs of $1.6 million were charged to gain on early extinguishment of debt, totaling $14.5 million.

The indenture governing our senior unsecured notes contains covenants that, among other things, limit the ability of our restricted subsidiaries to: (i) incur additional indebtedness, (ii) pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness, (iii) transfer or sell assets, (iv) make investments, (v) create certain liens, (vi) enter into agreements that restrict dividends or other payments to the Company from its restricted subsidiaries, (vii) consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries, taken as a whole, (viii) engage in transactions with affiliates, and (ix) create unrestricted subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the indenture. In addition, if the senior unsecured notes achieve an investment grade rating from either Moody's Investors Service, Inc. or Standard & Poor's Ratings Services, and no default under the indenture has then occurred and is continuing, many of such covenants will be suspended. The indenture also contains events of default, which include, among others and subject in certain cases to grace and cure periods, nonpayment of principal or interest, failure by the Company to comply with its other obligations under the indenture, payment defaults and accelerations with respect to certain other indebtedness of the Company and its restricted subsidiaries, failure of any guarantee on the senior unsecured notes to be enforceable, and certain events of bankruptcy or insolvency. We were in compliance with all applicable covenants in the indenture at June 30, 2017.

We have also entered into a $500 million revolving credit facility, which is governed by a Credit Agreement that includes customary affirmative and negative covenants. In February 2017, we entered into an amendment to our revolving credit facility that increased the borrowing base under such facility from $125 million to $175 million and extended the maturity date from January 2018 to February 2020. As of June 30, 2017, the borrowing base was $175 million and we had no outstanding borrowings. After giving effect to our outstanding letters of credit, totaling $33.6 million, we had available borrowing capacity under the revolving credit facility of $141.4 million. In August 2017, the borrowing base was redetermined, which increased the borrowing base from $175 million to $225 million. The Company's available borrowing capacity under the revolving credit facility is now $191.4 million. Our next scheduled borrowing base redetermination is expected to be completed by April 2018. We were in compliance with all applicable covenants in the Credit Agreement at June 30, 2017.

Commodity Hedging Activities

Our primary market risk exposure is in the prices we receive for our natural gas, NGLs and oil production. Realized pricing is primarily driven by the spot regional market prices applicable to our U.S. natural gas, NGLs and oil production. Pricing for natural gas, NGLs and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate the potential negative impact on our cash flow caused by changes in natural gas, NGLs and oil prices, we may enter into financial commodity derivative contracts to ensure that we receive minimum prices for a portion of our future natural gas production when management believes that favorable future prices can be secured. We typically hedge the NYMEX Henry Hub price for natural gas and the WTI price for oil.

Our hedging activities are intended to support natural gas, NGLs and oil prices at targeted levels and to manage our exposure to price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, zero cost collars that set a floor and ceiling price for the hedged production, and puts which require us to pay a premium either up front or at settlement and allow us to receive a fixed price at our option if the put price is above the market price. As of June 30, 2017, we had entered into the following derivative contracts:

Natural Gas Derivatives

Description	Volume (MMBtu/d)	Production Period	Weighted Average Price ($/MMBtu)
Natural Gas Swaps:			
	10,000	July 2017 – December 2017	$ 2.98
	10,000	July 2017 – December 2017	$ 3.21
	30,000	October 2017 – March 2018	$ 3.46
Natural Gas Three-way Collars:			
Floor purchase price (put)	160,000	July 2017 – December 2017	$ 2.83
Ceiling sold price (call)	160,000	July 2017 – December 2017	$ 3.37
Floor sold price (put)	160,000	July 2017 – December 2017	$ 2.31
Floor purchase price (put)	30,000	July 2017 – March 2019	$ 3.00
Ceiling sold price (call)	30,000	July 2017 – March 2019	$ 3.40
Floor sold price (put)	20,000	July 2017 – March 2019	$ 2.40
Floor sold price (put)	10,000	July 2017 – March 2019	$ 2.20
Floor purchase price (put)	20,000	October 2017 – December 2018	$ 2.90
Ceiling sold price (call)	20,000	October 2017 – December 2018	$ 3.50
Floor sold price (put)	20,000	October 2017 – December 2018	$ 2.20
Floor purchase price (put)	60,000	January 2018 – March 2018	$ 2.90
Ceiling sold price (call)	60,000	January 2018 – March 2018	$ 3.75
Floor sold price (put)	60,000	January 2018 – March 2018	$ 2.40
Floor purchase price (put)	60,000	April 2018 – December 2018	$ 2.90
Ceiling sold price (call)	60,000	April 2018 – December 2018	$ 3.25
Floor sold price (put)	60,000	April 2018 – December 2018	$ 2.40
Floor purchase price (put)	60,000	January 2018 – December 2018	$ 2.80
Ceiling sold price (call)	60,000	January 2018 – December 2018	$ 3.35
Floor sold price (put)	60,000	January 2018 – December 2018	$ 2.33
Floor purchase price (put)	20,000	July 2017 – December 2018	$ 2.90
Ceiling sold price (call)	20,000	July 2017 – December 2018	$ 3.25
Floor sold price (put)	20,000	July 2017 – December 2018	$ 2.40
Natural Gas Call/Put Options:			
Call sold	40,000	January 2018 – December 2018	$ 3.75
Call sold	10,000	January 2019 – December 2019	$ 4.75
Basis Swaps:			
TCO - Columbia	20,000	July 2017 – December 2017	$ (0.19)
Appalachia - Dominion	40,000	July 2017 – November 2017	$ (1.01)
Appalachia - Dominion	40,000	July 2017 – November 2017	$ (1.04)

Oil Derivatives

Description	Volume (Bbls/d)	Production Period	Weighted Average Price ($/Bbl)
Oil Three-way Collars:			
Floor purchase price (put)	2,000	July 2017 – September 2017	$ 46.00
Ceiling sold price (call)	2,000	July 2017 – September 2017	$ 59.50
Floor sold price (put)	2,000	July 2017 – September 2017	$ 38.00
Floor purchase price (put)	2,000	July 2017 – December 2017	$ 46.00
Ceiling sold price (call)	2,000	July 2017 – December 2017	$ 60.00
Floor sold price (put)	2,000	July 2017 – December 2017	$ 38.00

NGL Derivatives

Description	Volume (Gal/d)	Production Period	Weighted Average Price ($/Gal)
Propane Swaps:			
	84,000	July 2017 – December 2017	$ 0.60

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have derivative instruments in place with Bank of Montreal, Citibank, Goldman Sachs, Morgan Stanley and Key Bank N.A. We believe all of such institutions currently are an acceptable credit risk. As of June 30, 2017, we did not have any past due receivables from such counterparties.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at June 30, 2017. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $21.3 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $23.9 million. A hypothetical 10 percent decrease in future oil prices would increase future earnings related to derivatives by $1.3 million. Similarly, a hypothetical 10 percent increase in future oil prices would decrease future earnings related to derivatives by $0.8 million.

Subsequent to June 30, 2017, we entered into the following derivative instruments to mitigate our exposure to natural gas and oil prices:

Description	Volume (Bbls/d)	Production Period	Weighted Average Price ($/Bbl)
Oil Three-way Collars:			
Floor purchase price (put)	4,000	January 2018 – December 2018	$ 45.00
Ceiling sold price (call)	4,000	January 2018 – December 2018	$ 52.26
Floor sold price (put)	4,000	January 2018 – December 2018	$ 35.00

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of natural gas and oil properties and repayment of principal and interest on outstanding debt. Our board of directors approved an initial capital budget for 2017 of approximately $300 million. The budget includes approximately $261 million for drilling and completions activities, $33 million for land activities and $6 million for other capital requirements. In addition to these amounts, we expect to spend approximately $17 million during 2017 related to leases that were signed during 2016. The 2017 Capital Budget is expected to be substantially funded through internally generated cash flows and the Company's current cash balance. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in natural gas, NGLs or oil prices from current levels may result in a further decrease in our actual capital expenditures, which would negatively impact our ability to grow production and our proved reserves as well as our ability to maintain compliance with our debt covenants. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets.

In addition, we may from time to time seek to pay down, retire or repurchase our outstanding debt using cash or through exchanges of other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on available funds, prevailing market conditions, our liquidity requirements, contractual restrictions in our revolving credit agreement and other factors.

Capitalization

As of June 30, 2017 and December 31, 2016, our total debt, excluding debt discount, and capitalization were as follows (in millions):

	June 30, 2017	December 31, 2016
Senior unsecured notes	$510.5	$ 510.5
Stockholders' equity	597.3	556.6
Total capitalization	$1,107.8	$ 1,067.1

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, firm transportation, gas processing, gathering, and compressions services and asset retirement obligations. As of June 30, 2017 and December 31, 2016, we did not have any capital leases, any significant off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed any debt of any unrelated party. Our condensed consolidated balance sheet at June 30, 2017 reflects accrued interest payable of $21.2 million, compared to $21.1 million as of December 31, 2016.

Other

We lease acreage that is generally subject to lease expiration if operations are not commenced within a specified period, generally five years. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Interest Rates

At June 30, 2017 and December 31, 2016, we had $510.5 million of senior unsecured notes outstanding, excluding discounts, which bear interest at a fixed cash rate of 8.875% and is due semi-annually from the date of issuance.

In February 2014, we entered into a $500 million senior secured revolving bank credit facility. Borrowings under our revolving credit facility are subject to borrowing base limitations based on the collateral value of our proved properties and commodity hedge positions and are subject to semiannual redeterminations. In February 2017, we entered into an amendment to our revolving credit facility that increased the borrowing base under such facility from $125 million to $175 million and extended the maturity date of such facility from January 2018 to February 2020. As of June 30, 2017, the borrowing base was $175 million and we had no outstanding borrowings. After giving effect to our outstanding letters of credit, totaling $33.6 million, we had available borrowing capacity under the revolving credit facility of $141.4 million. In August 2017, the borrowing base was redetermined, which increased the borrowing base from $175 million to $225 million. The Company’s available borrowing capacity under the revolving credit facility is now $191.4 million. Our next scheduled borrowing base redetermination is expected to be completed by April 2018.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments which are described above under “—Cash Contractual Obligations.”

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, it does not normally have a significant effect on our business. We expect our costs in fiscal 2017 to continue to be a function of supply and demand. Further strengthening of commodity prices could stimulate demand for ancillary services causing services costs to increase. In the near term, the majority of our service costs are expected to remain flat in 2017 due to previously negotiated drilling, stimulation, and rentals contracts. Along with these contracts, we have secured quality service equipment and tenured personnel to limit our exposure to increasing service costs and improve operational efficacies.

Non-GAAP Financial Measure

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; DD&A; amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments) on settled derivative instruments, and premiums (paid) received on options that settled during the period; non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items set forth in the table below. Adjusted EBITDAX, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with U.S. GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with U.S. GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under the Credit Agreement governing the revolving credit facility and the indenture governing the senior unsecured notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from operations to Adjusted EBITDAX for the periods presented:

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
$ thousands	2017	2016	2017	2016
Net income (loss)	$11,494	$(73,163)	$38,341	$(118,697)
Depreciation, depletion and amortization	25,152	20,949	51,341	36,062
Exploration expense	8,997	17,444	20,577	33,100
Rig termination and standby	—	1,292	—	3,955
Impairment of proved oil and gas properties	—	—	—	17,665
Stock-based compensation	2,348	2,226	4,429	3,701
Accretion of asset retirement obligations	128	89	252	175
(Gain) loss on derivative instruments	(18,177)	29,596	(43,274)	19,046

Net cash receipts (payments) on settled derivatives	(2,644)	12,880	(6,633)	31,258
Interest expense, net	12,285	12,439	24,747	25,900
(Gain) loss on sale of assets	6	(1,024)	1	(1,046)
(Gain) loss on early extinguishment of debt	—	(5,825)	—	(14,489)
Other (income) expense	—	2	19	141
Income tax (benefit) expense	—	—	—	540
Adjusted EBITDAX	$39,589	$16,905	$89,800	$37,311

Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Annual Report on Form 10-K for further discussion of our critical accounting policies.

Recent Accounting Pronouncements

The Company's critical accounting policies are described in Note 3 – Summary of Significant Accounting Policies of the consolidated financial statements for the year ended December 31, 2016 contained in the Company's Annual Report on Form 10-K. Information related to recent accounting pronouncements is described in Note 3 to our condensed consolidated financial statements and is incorporated herein by reference.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are U.S. dollar denominated.

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 82% of our December 31, 2016 proved reserves were natural gas.

For a discussion of how we use financial commodity derivative contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see "Note 5—Derivative Instruments."

Interest Rate Risk

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior unsecured notes due 2023 at an issue price of 97.903% of the principal amount of the senior unsecured notes, plus accrued and unpaid interest, if any. At June 30, 2017, the cash interest rate with respect to the senior unsecured notes was fixed at 8.875%, and interest is due semi-annually from the date of issuance in January and July.

We will be exposed to interest rate risk in the future if we draw on our revolving credit facility. Interest on outstanding borrowings under our revolving credit facility will accrue based on, at our option, LIBOR or the alternate base rate, in each case, plus an applicable margin that is determined based on our utilization of commitments under our revolving credit facility. As of June 30, 2017, the borrowing base was $175 million and we had no outstanding borrowings. After giving effect to our outstanding letters of credit, totaling $33.6 million, we had available borrowing capacity under the revolving credit facility of $141.4 million. In August 2017, the borrowing base was redetermined, which increased the borrowing base from $175 million to $225 million. The Company's available borrowing capacity under the revolving credit facility is now $191.4 million.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts, the sale of our oil and gas production which we market to energy companies, end users and refineries, and joint interest receivables.

We are exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is subject to periodic review. We have not experienced any issues of nonperformance by derivative counterparties. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of June 30, 2017, we did not have past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The Company's management carried out an evaluation (as required by Rule 13a-15(b) of the Exchange Act), with the participation of the Company's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act), as of the end of the period covered by this Quarterly Report on Form 10-Q. Based upon this evaluation, the Company's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this Quarterly Report on Form 10-Q, such that the information relating to the Company and its consolidated subsidiaries required to be disclosed by the Company in the reports that it files or submits under the Exchange Act (i) is recorded, processed, summarized, and reported, within the time periods specified in the SEC's rules and forms, and (ii) is accumulated and communicated to the Company's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15(d)-15(f) under the Exchange Act) during the period covered by this Quarterly Report that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding the Company's legal proceedings is set forth in "Note 13—Commitments and Contingencies," located in the Notes to the Condensed Consolidated Financial Statements included in Part I Item 1 of this Quarterly Report on Form 10-Q and is incorporated herein by reference.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report on Form 10-Q, including the risk factor set forth below, you should carefully consider the factors discussed in "Risk Factors" in our Annual Report on Form 10-K filed with the SEC on March 3, 2017, which could materially affect our business, financial condition, and/or future results. The risks described in our Annual Report on Form 10-K 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 results of operations.

We may be unable to successfully negotiate or enter into definitive agreements regarding our proposed joint development transaction with Sequel Energy Group LLC, or to effectively implement that transaction, which failures could negatively affect our future financial performance or cause the market price of our securities to decline.

On August 1, 2017, we entered into an agreement and term sheet (collectively, the "Sequel Agreement") with Sequel Energy Group LLC, a Delaware limited liability company, relating to the potential joint development of certain oil, gas and mineral interest assets we own in the Utica Shale in southeast Ohio within the counties of Harrison, Guernsey, Belmont, and Monroe. The development plans set forth in those agreements will represent a significant portion of our development plans for our mineral interest assets for the next two to three years. Although the Sequel Agreement sets forth the material terms of the proposed transaction, it does not obligate either party to consummate such transaction. Rather, it requires the parties to negotiate in good faith for a period of time and to use their commercially reasonable efforts to document and enter into mutually agreeable definitive agreements relating to the proposed transaction. We cannot assure you that such negotiations will be successful, that we will enter into these definitive agreements and, if we do, what will be the final terms of such agreements. Additionally, each party's obligation to enter into these definitive agreements is subject to various conditions, including, without limitation, that all necessary consents and approvals have been received from applicable third parties and that no material adverse change has occurred with respect to the Company. Moreover, even if we do enter into definitive agreements, those agreements may require the parties to satisfy these and other conditions before the proposed transaction may be consummated. We cannot assure you as to when these conditions to proposed transaction will be satisfied or waived by the appropriate party, if at all. As a result, we cannot assure you that we will consummate this proposed transaction. If we are unable to successfully negotiate and enter into the definitive agreements or if we otherwise fail to consummate the proposed transaction, or if we are unable to effectively execute the terms of the definitive agreements, we may not be able to successfully develop a significant portion of our mineral interests or we may be forced to utilize more costly financing methods to do so. Such failures could materially and adversely impact our future financial performance, our reputation and our prospects for capital in the future, which may cause investors to lose confidence in us and our strategies, and as a result, could cause the market price of our securities to decline.

Item 6. Exhibits

See the list of exhibits in the index to exhibits to this Quarterly Report on Form 10-Q, which is incorporated herein by reference.

47

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.

August 3, 2017	ECLIPSE RESOURCES CORPORATION
	(Registrant)
	/s/ Benjamin W. Hulburt Benjamin W. Hulburt, Chairman, President and Chief Executive Officer
	/s/ Matthew R. DeNezza Matthew R. DeNezza, Executive Vice President and Chief Financial Officer

ECLIPSE RESOURCES CORPORATION

INDEX TO EXHIBITS

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Eclipse Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014).
3.2	Amended and Restated Bylaws of Eclipse Resources Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014).
4.1	Stockholders Agreement, dated June 25, 2014, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P. and Eclipse Management, L.P. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 30, 2014).
4.2	Amended and Restated Registration Rights Agreement, dated January 28, 2015, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Eclipse Management, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II (Luxembourg) S.à.r.l., Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 29, 2015).
4.3	Indenture, dated as of July 6, 2015, between Eclipse Resources Corporation, the guarantors party thereto and Deutsche Bank Trust Company Americas, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on July 8, 2015).
10.1	Eclipse Resources Corporation 2014 Long-Term Incentive Plan, as amended by the First Amendment (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on May 18, 2017).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certifications of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2**	

Certifications of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** These exhibits are furnished herewith and shall not be deemed “filed” for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act.