Eclipse Resources Corp
Form 10-Q
August 03, 2016

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016

or

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

Commission File Number: 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. x Yes o 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). x Yes o No

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

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

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

Number of shares of the registrant's common stock outstanding at August 3, 2016: 260,591,893 shares

ECLIPSE RESOURCES CORPORATION

QUARTERLY REPORT ON FORM 10-Q

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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 4, 2016.

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;
- 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, 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 4, 2016.

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, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 114,056	$ 184,405
Accounts receivable	25,485	27,476
Assets held for sale	184	21,971
Other current assets	4,981	35,532
Total current assets	144,706	269,384
PROPERTY AND EQUIPMENT AT COST		
Oil and natural gas properties, successful efforts method:		
Unproved properties	684,383	720,159
Proved oil and gas properties, net	263,069	265,838
Other property and equipment, net	7,423	7,971
Total property and equipment, net	954,875	993,968
OTHER NONCURRENT ASSETS		
Other assets	1,009	2,520
Deferred taxes	—	540
TOTAL ASSETS	$ 1,100,590	$ 1,266,412
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 34,753	$ 34,717
Accrued capital expenditures	7,880	10,956
Accrued liabilities	21,781	25,462
Accrued interest payable	20,919	23,809
Liabilities held for sale	—	18,898
Total current liabilities	85,333	113,842
NONCURRENT LIABILITIES		
Debt, net of unamortized discount and debt issuance costs	490,990	527,248
Asset retirement obligations	3,639	3,401

Other liabilities	10,409	1,367
Total liabilities	590,371	645,858
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, 223,091,686 and 222,674,270 shares issued and outstanding, respectively	2,232	2,227
Additional paid in capital	1,832,501	1,829,082
Treasury stock, shares at cost; 72,590 at June 30, 2016	(61)	—
Accumulated deficit	(1,324,453)	(1,210,755)
Total stockholders' equity	510,219	620,554
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 1,100,590	$ 1,266,412

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

ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)

(Unaudited)

	For the Three Months Ended June 30, 2016	2015	For the Six Months Ended June 30, 2016	2015
REVENUES				
Oil and natural gas sales	$45,901	$64,984	$86,389	$111,598
Brokered natural gas and marketing revenue	1,165	9,469	10,283	6,669
Total revenues	47,066	74,453	96,672	118,267
OPERATING EXPENSES				
Lease operating	2,248	3,589	4,925	6,935
Transportation, gathering and compression	28,254	22,634	51,391	35,085
Production and ad valorem taxes	2,051	3,078	(233)	5,178
Brokered natural gas and marketing expense	2,160	10,795	11,562	10,795
Depreciation, depletion and amortization	20,949	60,641	36,062	103,073
Exploration	17,444	6,243	33,100	19,696
General and administrative	10,402	12,717	21,676	24,660
Rig termination and standby	1,292	366	3,955	7,423
Impairment of proved oil and gas properties	—	—	17,665	—
Accretion of asset retirement obligations	89	399	175	785
(Gain) loss on sale of assets	(1,024)	(5,553)	(1,046)	(5,473)
Total operating expenses	83,865	114,909	179,232	208,157
OPERATING LOSS	(36,799)	(40,456)	(82,560)	(89,890)
OTHER INCOME (EXPENSE)				
Gain (loss) on derivative instruments	(29,596)	(3,523)	(19,046)	7,848
Interest expense, net	(12,439)	(14,401)	(25,900)	(28,422)
Gain on early extinguishment of debt	5,825	—	14,489	—
Other income (expense)	(2)	(2)	(141)	400
Total other expense, net	(36,212)	(17,926)	(30,598)	(20,174)
LOSS BEFORE INCOME TAXES	(73,011)	(58,382)	(113,158)	(110,064)
INCOME TAX BENEFIT (EXPENSE)	—	16,412	(540)	33,991
NET LOSS	$(73,011)	$(41,970)	$(113,698)	$(76,073)
NET LOSS PER COMMON SHARE				
Basic and diluted	$(0.33)	$(0.19)	$(0.51)	$(0.36)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING				
Basic and diluted	223,013	222,502	222,898	213,178

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

ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(In thousands)

(Unaudited)

	For the Three Months Ended		For the Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
NET LOSS	$(73,011)	$(41,970)	$(113,698)	$(76,073)
Other comprehensive income (loss):				
Pension obligation adjustment, net of tax	—	192	—	(18)
TOTAL COMPREHENSIVE LOSS	$(73,011)	$(41,778)	$(113,698)	$(76,091)

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, 2015	222,674,270	$ 2,227	$ 1,829,082	$ —	$ (1,210,755)	$ 620,554
Stock-based compensation	—	—	3,701	—	—	3,701
Equity issuance costs	—	—	(277)	—	—	(277)
Issuance of restricted stock	149,448	2	(2)	—	—	—
Issuance of common stock upon vesting of equity-based compensation awards, net of shares withheld for income tax withholdings	267,968	3	(3)	(61)	—	(61)
Net loss	—	—	—	—	(113,698)	(113,698)
Balances, June 30, 2016	223,091,686	$ 2,232	$ 1,832,501	$ (61)	$ (1,324,453)	$ 510,219

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, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$(113,698)	$(76,073)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities		
Depreciation, depletion and amortization	36,062	103,073
Exploration expense	18,722	6,073
Pension benefit costs	—	101
Stock-based compensation	3,701	2,157
Impairment of proved oil and gas properties	17,665	—
Accretion of asset retirement obligations	175	785
(Gain) loss on derivative instruments	19,046	(7,848)
Net cash receipts (payments) on settled derivatives	31,258	14,422
(Gain) loss on sale of assets	(1,046)	(5,473)
Gain on early extinguishment of debt	(14,489)	—
Deferred income taxes	540	(34,107)
Interest not paid in cash	—	1,232
Amortization of deferred financing costs	972	1,018
Amortization of debt discount	691	1,193
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(1,238)	13,007
Other assets	(2,586)	225
Accounts payable and accrued liabilities	(13,026)	29,724
Net cash provided by (used in) operating activities	(17,251)	49,509
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures for oil and gas properties	(42,913)	(327,856)
Capital expenditures for other property and equipment	(416)	(1,284)
Proceeds from sale of assets	14,094	37,287
Net cash used in investing activities	(29,235)	(291,853)
CASH FLOWS FROM FINANCING ACTIVITIES		
Debt issuance costs	261	(1,577)
Repayments of long-term debt	(23,786)	(207)
Proceeds from issuance of common stock	—	440,000
Equity issuance costs	(277)	(5,767)
Employee tax withholding for settlement of equity compensation awards	(61)	—
Net cash provided by (used in) financing activities	(23,863)	432,449

Net increase (decrease) in cash and cash equivalents	(70,349)	190,105
Cash and cash equivalents at beginning of period	184,405	67,517
Cash and cash equivalents at end of period	$114,056	$257,622
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid for interest	$25,175	$13,080
Cash paid for income taxes	$—	$37
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:		
Asset retirement obligations incurred, including changes in estimate	$63	$303
Additions of other property through debt financing	$—	$888
Additions to oil and natural gas properties - changes in accounts payable, accrued liabilities, and accrued capital expenditures	$123	$(88,418)
Interest paid-in-kind	$—	$14,786

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, 2015, 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. 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 4, 2016.

Operating results for interim periods may not necessarily be indicative of the results of operations for the full year ending December 31, 2016 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, 2016 or December 31, 2015.

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 $21.6 million and $19.9 million of accrued revenues, net of certain expenses at June 30, 2016 and December 31, 2015, 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. 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,

	2016	December 31, 2015
Oil and natural gas properties:		
Unproved	$684,383	$720,159
Proved	1,338,546	1,288,609
Gross oil and natural gas properties	2,022,929	2,008,768
Less accumulated depreciation depletion and amortization	(1,075,477)	(1,022,771)
Oil and natural gas properties, net	947,452	985,997
Other property and equipment	11,169	10,753
Less accumulated depreciation	(3,746)	(2,782)
Other property and equipment, net	7,423	7,971
Property and equipment, net	$954,875	$993,968

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 $0.3 million and $1.1 million for the three months ended June 30, 2016 and 2015, respectively. The Company capitalized interest expense totaling $0.5 million and $2.6 million for the six months ended June 30, 2016 and 2015, 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, 2016 or December 31, 2015.

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, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Receivables by product or service:		
Sale of oil and natural gas and related products and services	$21,625	$ 19,858

Joint interest owners	2,493	3,095
Derivatives	1,294	4,523
Miscellaneous other	73	—
Total	$25,485	$ 27,476

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 ($12.6) million and a net asset position of $34.4 million at June 30, 2016 and December 31, 2015, respectively. Other than as provided by the 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, 2016 and December 31, 2015, the Company did not have past-due receivables from or payables to any of such counterparties.

(f) Accumulated Other Comprehensive Income (Loss)

Comprehensive loss includes net loss and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net loss. These changes, other than net loss, are referred to as "other comprehensive loss" and for the Company they include a pension benefit plan that requires the Company to (i) recognize the overfunded or underfunded status of a defined benefit retirement plan as an asset or liability in its consolidated balance sheet and (ii) recognize changes in that funded status in the year in which the changes occur through other comprehensive loss. The Company's pension plan was terminated in October 2015 and lump sum payments were made in final settlement to all remaining participants.

(g) 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 $20.4 million and $60.1 million for the three months ended June 30, 2016 and 2015, respectively, and $35.0 million and $102.2 million for the six months ended June 30, 2016 and 2015, 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 and $0.5 million for the three months ended June 30, 2016 and 2015, respectively, and $1.0 million and $0.8 million for the six months ended June 30, 2016 and 2015, respectively. This amount is included in DD&A expense in the condensed consolidated statements of operations.

(h) 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, 2015 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 properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. 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 $9.4 million and $4.4 million for the three months ended June 30, 2016 and 2015, respectively, and approximately $18.7 million and $6.0 million for the six months ended June 30, 2016 and 2015, respectively. The increase in impairment charges during the three and six months ended June 30, 2016 is the result of an increase in expected lease expirations due to the reduction in the Company's planned future drilling activity due to the current commodity pricing environment. These costs are included in exploration expense in the condensed consolidated statements of operations.

(i) 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.

(j) 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 date 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.

(k) 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.

(l) 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% and 10.45% for the six months ended June 30, 2016 and 2015, respectively.

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, 2016 (in thousands):

	Six Months Ended June 30, 2016
Asset retirement obligations, beginning of period	$ 3,401
Additional liabilities incurred	63
Accretion	175
Asset retirement obligations, end of period	$ 3,639

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.

(m) Lease Obligations

The Company leases office space under operating leases that expire between the years 2016 to 2025. The lease terms begin 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 terms unless the renewals are deemed to be reasonably assured at lease inception.

(n) Off-Balance Sheet Arrangements

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

(o) 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.

(p) 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.

(q) Recent Accounting Pronouncements

The FASB issued Accounting Standards Update ("ASU") No. 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. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

In August 2014, the FASB issued ASU 2014-15, "Presentation of Financial Statements—Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The new standard provides guidance on determining when and how to disclose going concern uncertainties in the financial statements. Management will be required to perform interim and annual assessments of the Company's ability to continue as a going concern within one year of the date and financial statements are issued. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and interim periods within those years, with early adoption permitted. The adoption of this standard is not expected to have a significant impact on the Company's financial statement disclosures.

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. The Company is evaluating the impact of the adoption of ASU 2016-02 on its financial position, results of operations and related disclosures.

In March 2016, the FASB issued ASU 2016-09, "Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting." The new standard provides guidance involving several aspects of the accounting for share-based payments transactions, including income tax consequences, award classification as liabilities or equity, and cash flow statements classifications. These requirements are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. The Company is evaluating the impact of the adoption of ASU 2016-09 on its financial position, results of operations and related disclosures.

(r) Change in estimates

During the three months ended June 30, 2016, the Company reduced its estimate of amounts due from a non-operated partner related to the sale of natural gas and NGLs, net of associated costs, based on revised information received from the non-operated partner during the period. As a result, the Company decreased accounts receivable by approximately $4 million, increased revenue from oil and natural gas sales by approximately $1.5 million, and increased transportation, gathering and compression expense by approximately $5.8 million, which increased the net loss for the three and six months ended June 30, 2016 by approximately $4 million, or $0.02 per common share.

During the six months ended June 30, 2016, the Company reduced its estimate for production and ad valorem tax expense based on recent historical experience and additional information received during the period. As a result, the Company decreased the accrual for production and ad valorem taxes to be paid by approximately $4 million, which decreased the net loss for the six months ended June 30, 2016 by a corresponding amount, or $0.02 per common share.

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.

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, 2016, the Company's derivative instruments were with Bank of Montreal, Citibank, N.A., 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, 2016, for future production periods:

Natural Gas Derivatives

Description	Volume (MMBtu/d)	Production Period	Weighted Average Price ($/MMBtu)
Natural Gas Swaps:			
	65,000	July 2016 – December 2016	$ 3.28
	10,000	January 2017 – December 2017	$ 2.98
Natural Gas Collars:			
Floor purchase price (put)	30,000	July 2016 – December 2017	$ 3.00

Ceiling sold price (call)	30,000	July 2016 – December 2017	$	3.50
Floor purchase price (put)	50,000	January 2017 – December 2017	$	3.00
Ceiling sold price (call)	50,000	January 2017 – December 2017	$	3.20
Floor purchase price (put)	20,000	January 2017 – December 2017	$	2.75
Ceiling sold price (call)	20,000	January 2017 – December 2017	$	3.29
Floor purchase price (put)	30,000	January 2017 – December 2017	$	2.50
Ceiling sold price (call)	30,000	January 2017 – December 2017	$	3.03
Natural Gas Three-way Collars:				
Floor purchase price (put)	40,000	July 2016 – December 2016	$	2.90
Ceiling sold price (call)	40,000	July 2016 – December 2016	$	3.24
Floor sold price (put)	40,000	July 2016 – December 2016	$	2.35
Floor purchase price (put)	30,000	January 2017 – December 2017	$	2.75
Ceiling sold price (call)	30,000	January 2017 – December 2017	$	3.57
Floor sold price (put)	30,000	January 2017 – December 2017	$	2.25
Natural Gas Call/Put Options:				
Put sold	16,800	July 2016 – December 2016	$	2.75
Call sold	40,000	January 2018 – December 2018	$	3.75

Oil Derivatives

Description	Volume (Bbls/d)	Production Period	Weighted Average Price ($/Bbl)
Oil Swaps:			
	850	July 2016 – December 2016	$ 45.55
Oil Three-way Collars:			
Floor purchase price (put)	1,000	July 2016 – December 2016	$ 60.00
Ceiling sold price (call)	1,000	July 2016 – December 2016	$ 70.10
Floor sold price (put)	1,000	July 2016 – December 2016	$ 45.00
Floor purchase price (put)	2,000	January 2017 – September 2017	$ 46.00
Ceiling sold price (call)	2,000	January 2017 – September 2017	$ 59.50
Floor sold price (put)	2,000	January 2017 – September 2017	$ 38.00
Floor purchase price (put)	2,000	January 2017 – December 2017	$ 46.00
Ceiling sold price (call)	2,000	January 2017 – December 2017	$ 60.00
Floor sold price (put)	2,000	January 2017 – December 2017	$ 38.00
Oil Call/Put Options:			
Call sold	1,000	January 2018 – December 2018	$ 50.00

NGL Derivatives

Description	Volume (Gal/d)	Production Period	Weighted Average Price ($/Gal)
Propane Swaps:			
	42,000	July 2016 – December 2016	$ 0.46
	10,500	July 2016 – September 2016	$ 0.46

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, 2016	Gross Amount	Netting Adjustments(a)	Net Amount Presented in Balance Sheets	Balance Sheet Location
Assets				
Commodity derivatives - current	$4,501	$ (4,501)	$—	
Commodity derivatives - noncurrent	321	(321)	—	
Total assets	$4,822	$ (4,822)	$—	
Liabilities				
Commodity derivatives - current	$(7,703)	$ 4,501	$(3,202)	Accrued liabilities
Commodity derivatives - noncurrent	(9,752)	321	(9,431)	Other liabilities
Total liabilities	$(17,455)	$ 4,822	$(12,633)	

As of December 31, 2015	Gross Amount	Netting Adjustments(a)	Net Amount Presented in Balance Sheets	Balance Sheet Location
Assets				
Commodity derivatives - current	$41,199	$ (8,158)	$ 33,041	Other current assets
Commodity derivatives - noncurrent	4,594	(3,194)	1,400	Other assets
Total assets	$45,793	$ (11,352)	$ 34,441	
Liabilities				
Commodity derivatives - current	$(8,158)	$ 8,158	$ —	
Commodity derivatives - noncurrent	(3,194)	3,194	—	
Total liabilities	$(11,352)	$ 11,352	$ —	

(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			
		Three Months Ended June 30,		Six Months Ended June 30,	
Derivatives not designated as hedging instruments under ASC 815	Location of Gain (Loss) Recognized in Income	2016	2015	2016	2015
Commodity derivatives	Gain (Loss) on derivative instruments	$(29,596)	$(3,523)	$(19,046)	$7,848

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, 2016: (in thousands)				
Commodity derivative instruments	$ —	$(12,633)	$ —	$ (12,633)
Total	$ —	$(12,633)	$ —	$ (12,633)

	Level 1	Level 2	Level 3	Total Fair Value
As of December 31, 2015: (in thousands)				
Commodity derivative instruments	$ —	$34,441	$ —	$ 34,441
Total	$ —	$34,441	$ —	$ 34,441

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

12% Senior Unsecured PIK Notes Due 2018

The Company redeemed all of the outstanding balance of the 12% Senior PIK Notes on July 13, 2015 for approximately $510.7 million, including outstanding principal balance of $437.3 million, a make-whole premium of $47.6 million, and accrued interest of $25.8 million. The make-whole premium plus unamortized discount and deferred financing costs of $11.8 million were charged to loss on early extinguishment of debt, totaling $59.4 million. The Company amortized $0.5 million and $2.2 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, 2015, respectively.

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 (the "Notes") 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 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 intends to use the remaining net proceeds to fund its capital expenditure plan and for general corporate purposes. The fair value of the Notes at June 30, 2016 was $482.4 million.

During the three and six months ended June 30, 2016, 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 Indenture governing the Notes (the “Indenture”) 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 Notes achieve and 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 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, 2016.

During the three months ended June 30, 2016, the Company repurchased $21.0 million of the outstanding Notes in open market purchases for $14.3 million. During the six months ended June 30, 2016, the Company repurchased $39.5 million of the outstanding Notes in open market purchases for $23.4 million. The principal of the outstanding 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 $5.8 million and $14.5 million for the three and six months ended June 30, 2016, respectively. The Company repurchased all such Notes with cash on hand.

Revolving Credit Facility

The Company has 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). At June 30, 2016, the borrowing base was $125 million and the Company had no outstanding borrowings. After giving effect to outstanding letters of credit issued by the Company totaling $27.8 million, the Company had available borrowing capacity under the Revolving Credit Facility of $97.2 million at June 30, 2016.

On February 24, 2016, the Company amended the Credit Agreement governing its Revolving Credit Facility (the "Credit Agreement") to, among other things, adjust the Company's 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 Credit Agreement also 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.

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 Credit Agreement 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 Credit Agreement as of June 30, 2016. Commitment fees on the unused portion of the Revolving Credit Facility are due quarterly at rates ranging from 0.375% to 0.50% 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 recognized expense of $0.1 million and

$0.3 million for the three months ended June 30, 2016 and 2015, respectively, and $0.4 million and $0.5 million for the six months ended June 30, 2016 and 2015, respectively.

Defined Benefit Plan

The Company maintained a defined benefit plan until October 2015. The plan covered 28 employees, of which two were retired, four had deferred vested determination, and one was a survivor. Benefits were based on the employees' years of service and compensation. The following table details the components of pension benefit cost (in thousands):

	For the Three Months Ended June 30, 2015	For the Six Months Ended June 30, 2015
Interest cost	$ 62	$ 126
Expected return on plan assets	(82)	(164)
Amortization of net loss	25	43
Settlement costs	96	96
Net periodic benefit cost	$ 101	$ 101

The defined benefit plan was terminated during October 2015 and lump sum payments were made to the remaining participants.

Note 9—Stock-Based Compensation

The Company is authorized to grant up to 16,000,000 shares of common stock under its 2014 Long-Term Incentive Plan (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 8,024,622 shares were available for future grants under the Plan as of June 30, 2016.

Our stock-based compensation expense is as follows for the three and six months ended June 30, 2016 and 2015 (in thousands):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2016	2015	2016	2015
Restricted stock units	$ 1,388	$ 748	$ 2,243	$ 1,171
Performance units	677	376	1,057	528
Restricted stock issued to directors	142	255	353	400

Incentive units	19	31	48	58
Total expense	$ 2,226	$ 1,410	$3,701	$2,157

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, 2016, there was $7.7 million of total unrecognized compensation cost related to outstanding restricted stock units. A summary of restricted stock unit awards activity during the six months ended June 30, 2016 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2015	1,000,052	$ 7.07	$ 1,820
Granted	3,742,985	1.36	
Vested	(340,558)	7.13	
Forfeited	(63,259)	7.13	
Total awarded and unvested, June 30, 2016	4,339,220	$ 2.14	$ 14,493

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, 2016, there was $4.3 million of total unrecognized compensation cost related to outstanding performance units. A summary of performance stock unit awards activity during the six months ended June 30, 2016 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands
Total awarded and unvested, December 31, 2015	458,656	$ 8.77	$ 417
Granted	1,469,346	1.60	
Vested	—	—	
Forfeited	—	—	
Total awarded and unvested, June 30, 2016	1,928,002	$ 3.31	$ 8,127

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 October 7, 2014, the Company issued an aggregate of 31,115 restricted shares of common stock to its seven non-employee members of its Board of Directors, which became fully vested on June 25, 2015. For the three and six months ended June 30, 2015, the Company recognized expense of approximately $0.1 million and $0.2 million related to these awards, respectively.

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, 2015, the Company recognized expense of approximately $0.1 million related to these awards. 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 are scheduled to fully vest on May 18, 2017. For the three and six months ended June 30, 2016, the Company recognized expense of approximately $0.1 million related to these awards. As of June 30, 2016, there was approximately $0.4 million of total unrecognized compensation cost related to outstanding restricted stock issued to the Company’s directors.

Note 10—Equity

Private Placement of Common Stock

On December 27, 2014, the Company entered into a Securities Purchase Agreement with private equity funds managed by EnCap Investments L.P., entities controlled by certain members of the Company's management team and certain other institutional investors pursuant to which the Company issued and sold to such purchasers an aggregate of 62,500,000 shares of common stock at a price of $7.04 per share pursuant to the exemptions from registration provided in Rule 506 of Regulation D promulgated under Section 4(2) of the Securities Act (the "Private Placement").

On January 28, 2015, the Company closed the Private Placement and received net proceeds of approximately $434 million (after deducting placement agent commissions and estimated expenses), which the Company intends to use to fund its capital expenditure plan and for general corporate purposes.

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 intends to use to fund its capital expenditure plan and for general corporate purposes.

Note 11—Related Party Transactions

During each of the three and six months ended June 30, 2016 and 2015, the Company incurred approximately $0.1 million and $0.3 million, respectively, 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 fees are paid in accordance with a standard service contract that does not obligate the Company to any minimum terms.

Note 12—Commitments and Contingencies

(a) Legal Matters

Prior to the Oxford Acquisition, Oxford commenced a lawsuit on October 24, 2011 in the Common Pleas Court of Belmont County, Ohio against Mr. Barry West, a lessor under an Oxford oil and gas lease, to enforce its rights to access and drill a well pursuant to the lease during its initial 5-year primary term. The lessor counterclaimed, alleging, among other things, that the challenged Oxford lease constituted a lease in perpetuity and, accordingly, should be deemed void and contrary to public policy in the State of Ohio. On October 4, 2013, the Belmont County trial court granted a motion for summary judgment in favor of the lessor and ruled that the lease is a "no term" perpetual lease and, as such, is void as a matter of Ohio law.

The Company has appealed the trial court's decision in the West case to the Ohio Court of Appeals for the Seventh Appellate District, arguing, among other things, that the Belmont County trial court erred in finding that the lease is a "no term" perpetual lease, by ruling that perpetual leases are void as a matter of Ohio law and by invalidating such leases. The Company cannot predict the outcome of this lawsuit or the amount of time and expense that will be required to resolve the lawsuit.

In addition, many of the Company's other oil and gas leases in Ohio contain provisions identical or similar to those found in the challenged Oxford lease. As of August 3, 2016, we are a party to one other lawsuit that makes allegations similar to those made by the lessor in the West lawsuit. This lawsuit, together with the West case, affect approximately 157 gross (157 net) leasehold acres and were capitalized on our condensed consolidated balance sheet as of June 30, 2016 at $0.6 million.

The Company has undertaken efforts to amend the other leases acquired within the Utica Core Area in the Oxford Acquisition to address the issues raised by the trial court's ruling in the West case. These efforts have resulted in modifications to leases covering approximately 27,770 net acres out of the approximately 46,549 net acres. The Company's efforts may require modification to address the issues raised by the trial court while the Company's appeal is pending; however, the Company cannot predict whether the Company will be able to obtain modifications of the leases covering the remaining 18,779 net acres to effectively resolve issues related to the West trial court's ruling or the amount of time and expense that will be required to amend these leases.

In light of the foregoing, if the appeals court affirms the trial court ruling in the West case, and if other courts in Ohio adopt a similar interpretation of the provisions in other oil and gas leases the Company acquired in the Oxford Acquisition, other lessors may challenge the validity of such leases and those challenged leases may be declared void. Consequently, this could result in a loss of the mineral rights and an impairment of the related assets which could have a material adverse impact on the Company's financial statements. These costs could potentially be impaired if it was determined that the West lawsuit leases are invalid. Other than this potential impairment, the Company is not able to estimate the range of other potential losses related to this matter.

On September 26, 2014, the Ohio Court of Appeals for the Seventh Appellate District, the same appellate court that will decide the Company's appeal in the West case, issued its decision in the case of Clyde Hupp et al. v. Beck Energy Corporation, an appeal of a Monroe County trial court decision upon which the trial court in West based its decision. The appellate court held that while Ohio law disfavors perpetual leases, courts in Ohio have not found them to be per se illegal or void from their inception. The appellate court further held that the trial court misinterpreted both the pertinent lease provisions and Ohio law on the subject and erred in concluding that the Beck Energy lease is a no-term, perpetual lease that is void ab initio as against public policy. On November 7, 2014, the plaintiff landowners filed an appeal of the appellate court's decision with the Supreme Court of Ohio, which was accepted by the Supreme Court of Ohio on January 28, 2015. On March 2, 2015, the Ohio Court of Appeals for the Seventh Appellate District stayed all proceedings in the Company's appeal in the West case pending a decision by the Supreme Court of Ohio in the Hupp v. Beck Energy appeal. On January 21, 2016, the Supreme Court of Ohio affirmed the Appellate Court's decision in Hupp v. Beck Energy and held that the subject lease was not perpetual and not void as against public policy. As a result of such ruling, on February 26, 2016, the Appellate Court lifted the stay of the Company's appeal in the West case, and therefore, the Company's appeal will move forward in the Appellate Court.

The Company believes that there are strong grounds for appeal of the West decision, and therefore, the Company intends to pursue all available appellate rights, and to vigorously defend against the claims in this lawsuit. Based on the merits of the Company's appeal and the favorable holdings in the Hupp v. Beck Energy appellate decision described above, the Company believes that it is not probable that the trial court's decision in West will be upheld in the appeal or that the Company will incur a material loss in the lawsuit. The Company has not recorded an accrual for the potential losses attributable to this lawsuit.

Other 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 operating leases that expire between the years 2016 to 2025. The Company recognized rent expense of \$0.4 million and \$0.2 million for the three months ended June 30, 2016 and 2015, respectively, and \$0.6 million and \$0.4 million for the six months ended June 30, 2016 and 2015, respectively.

Note 13—Income Tax

For the year ended December 31, 2016, the Company's annual estimated effective tax rate is forecasted to be 0%, exclusive of discrete items. The Company expects to incur both a book and tax loss in fiscal year 2016, and thus, no current federal income taxes are anticipated to be paid. The Company computes its quarterly taxes under the effective tax rate method based on applying an anticipated annual effective tax rate to the Company's year-to-date loss. For the quarter ended June 30, 2016, 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.

In forecasting the 2016 annual estimated effective tax rate, management believes that it should limit any tax benefit suggested by the tax effect of the forecasted book loss such that no net deferred tax asset is recorded in 2016. Management reached this conclusion considering several factors such as: (i) the Company's short tax history, (ii) the lack of carryback potential resulting in a tax refund, and (iii) in light of current commodity pricing uncertainty, there is insufficient external evidence to suggest that net tax attribute carryforwards are collectible beyond offsetting existing deferred tax liabilities inherent in the Company's balance sheet. At this time, the estimated valuation allowance to be recorded in 2016 is \$40.1 million.

During the second quarter of 2016, the Internal Revenue Service notified the Company that it would examine the federal income tax return of Eclipse Resources Corporation and Subsidiaries for its 2014 tax year. The Company does not anticipate any material adjustments to its provision for income taxes as a result of the examination, as such no reserve has been recorded at this time.

Note 14—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.

Note 15—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 10—Equity).

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, 2015 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, 2016, we had assembled an acreage position approximating 213,000 net acres in Eastern Ohio.

Approximately 102,000 of our net acres are located in the Utica Shale fairway, which we refer to as the Utica Core Area, and approximately 13,000 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 Project Area. We are the operator of approximately 88% of our net acreage within the Utica Core Area and Our Marcellus Project 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, 2016, we, or our operating partners, had commenced drilling 202 gross wells within the Utica Core Area and Our Marcellus Project Area, of which 7 gross were drilling, 22 gross were awaiting completion or were in the process of being completed, 3 gross were awaiting midstream, and 170 gross had been turned to sales.

As of June 30, 2016, we were operating 1 horizontal rig in the Utica Core Area, which had resumed drilling during the quarter. We had average daily production for the three months ended June 30, 2016 of approximately 236.1 MMcfe comprised of approximately 71% natural gas, 19% NGLs and 10% 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 Project 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, 2016

Operationally, our performance during the three and six months ended June 30, 2016 reflects the continued development of our acreage, while focusing on capital preservation in the currently depressed commodity price environment.

During the three months ended June 30, 2016, we achieved the following financial and operating results:

- increased our average daily net production for the three months ended June 30, 2016 by 19% over the comparable period of the prior year, to 236.1 MMcfe per day;
- commenced drilling 2 gross operated Utica Shale wells ;
- commenced the completions of 4 gross operated Utica Shale wells ;
- recognized a net loss of $73.0 million for the three months ended June 30, 2016 compared to $42.0 million for the three months ended June 30, 2015; and
- realized Adjusted EBITDAX of $17.1 million for the three months ended June 30, 2016 compared to $31.5 million for three months ended June 30, 2015. Adjusted EBITDAX is a non-GAAP financial measure. See “Non-GAAP Financial Measure” for more information.

During the six months ended June 30, 2016, we achieved the following financial and operating results:

- increased our average daily net production for the six months ended June 30, 2016 by 22% over the comparable period of the prior year, to 218.6 MMcfe per day;
- commenced drilling 3 gross operated Utica Shale wells ;
- completed the drilling of our over 18,500 foot extended reach lateral well in 17.6 days to total depth;
- commenced the completions of 5 gross operated Utica Shale wells ;
- recognized a net loss of $113.7 million for the six months ended June 30, 2016 compared to $76.1 million for the six months ended June 30, 2015; and
- realized Adjusted EBITDAX of $42.3 million for the six months ended June 30, 2016 compared to $52.2 million for the six months ended June 30, 2015. 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 and low NYMEX Henry Hub prices for natural gas and NYMEX WTI prices for oil for the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
NYMEX Henry Hub High ($/MMBtu)	$2.94	$3.04	$2.94	$3.32
NYMEX Henry Hub Low ($/MMBtu)	1.71	2.50	1.49	2.50
Average NYMEX Henry Hub ($/MMBtu)	2.16	2.74	2.09	2.81
NYMEX WTI High ($/Bbl)	$51.23	$61.36	$51.23	$61.36
NYMEX WTI Low ($/Bbl)	34.30	49.13	26.19	43.39

Average NYMEX WTI ($/Bbl)	46.21	57.67	40.88	53.19

Historically, commodity prices have been extremely volatile, and we expect this volatility to continue for the foreseeable future. A further or extended 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 significant price declines we have recently experienced have and could continue to adversely affect the amount of oil, NGLs and natural gas that we can produce economically, which has resulted in our having to make significant downward adjustments to our estimated proved undeveloped reserves. A reduction in production could also result in a shortfall in expected cash flows and require us to reduce capital spending or raise funds to cover any such shortfall. Any of these factors could negatively affect our ability to replace production and our future rate of growth or dilute existing shareholders.

Commodity price revisions, based on 12-month average SEC prices for 2015, had a significant impact on our 2015 reserve revisions. If the currently depressed pricing environment for oil, NGLs and natural gas persists or worsens, it will continue to have a significant impact on future reserve estimates. From December 31, 2015 to June 30, 2016, the 12-month average SEC price for WTI oil declined from $50.28 per Bbl to $43.12 per Bbl, while the 12-month average SEC price for Henry Hub natural gas declined from $2.59 per MMBtu to $2.24 per MMBtu. We expect to continue to increase our proved reserves through further extensions and discoveries as we continue to develop our acreage position.

Based on the current market conditions, we voluntarily reduced our aggregate operated production to approximately 200 MMcfe per day during the first half of 2016, which was approximately the same level as our 2015 average daily production. In addition, during the year ended December 31, 2015 we reduced the number of our operated horizontal drilling rigs down to one, compared to three horizontal rigs as of December 31, 2014. During the fourth quarter of 2015, we temporarily suspended all drilling operations and focused our initial 2016 capital plan on limiting cash outflows on drilling. As a result of the reduction in drilling activity, we recorded a charge related to the early termination of drilling rig contracts and standby costs of $4.0 million and $7.4 million during the six months ended June 30, 2016 and 2015 , respectively. This reduction in planned capital expenditures will likely result in a slower rate of growth of our proved reserves through extensions and discoveries than previously forecasted as development of our acreage position is deferred to subsequent years. As of June 30, 2016, we have recommenced drilling operations and began completing our drilled uncompleted well inventory. See additional details related to our capital expenditures in "—Capital Requirements."

As a result of the decline in commodity prices, we recognized impairment expenses relating to proved properties of $17.7 million for the six months ended June 30, 2016 i n the Marcellus Shale. For the three and six months ended June 30, 2015 and the three months ended June 30, 2016, we did not recognize impairment expenses relating to proved properties. In addition, we recognized impairment expenses relating to unproved properties of $18.7 million and $6.0 million for the six months ended June 30, 2016 and 2015, respectively. The increase in impairment charges related to unproved properties during the six months ended June 30, 2016 is the result of an increase in expected lease expirations due to the reduction in our planned future drilling activity due to the current pricing environment.

We consider future commodity prices when determining our development plan, but many other factors are also considered. Although the magnitude of change in these collective factors within a sustained low commodity price environment is difficult to estimate, we currently expect to execute our development plan based on current conditions. 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 December 31, 2015, proceeds from our recently completed follow-on equity offering, 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, 2016 Compared to Three Months Ended June 30, 2015

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

The following table illustrates the revenue attributable to natural gas, NGLs and oil sales for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		
	2016	2015	Change
Revenues (in thousands)			
Natural gas sales	$ 23,888	$ 28,175	$ (4,287)
NGL sales	9,331	9,563	(232)
Oil sales	12,682	27,246	(14,564)
Total revenues	$ 45,901	$ 64,984	$ (19,083)

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Our production grew by approximately 3.4 Bcfe for the three months ended June 30, 2016 over the same period in 2015 as we placed new wells into production, partially offset by natural decline and voluntary curtailment of our operated production. Our production for the three months ended June 30, 2016 and 2015 is set forth in the following table:

	Three Months Ended June 30,		
	2016	2015	Change
Production:			
Natural gas (MMcf)	15,298.5	10,385.9	4,912.6
NGL sales (Mbbls)	685.9	682.7	3.2
Oil sales (Mbbls)	345.2	599.1	(253.9)
Total (MMcfe)	21,485.1	18,076.5	3,408.6
Average daily production volume:			
Natural gas (Mcf/d)	168,115	114,131	53,984
NGL sales (Bbls/d)	7,537	7,502	35
Oil sales (Bbls/d)	3,793	6,584	(2,791)
Total (Mcfe/d)	236,095	198,643	37,452

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, 2016 was $2.42 per Mcfe compared to $3.82 per Mcfe during the three months ended June 30, 2015. 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, 2016 and 2015 are shown below:

	Three Months Ended		
	June 30,		
	2016	2015	Change
Average Sales Price (excluding cash settled derivatives)			
Natural gas ($/Mcf)	$ 1.56	$ 2.71	$ (1.15)
NGLs ($/Bbl)	13.60	14.01	(0.41)
Oil ($/Bbl)	36.74	45.48	(8.74)
Total average prices ($/Mcfe)	2.14	3.59	(1.45)
Average Sales Price (including cash settled derivatives)			
Natural gas ($/Mcf)	$ 2.31	$ 3.46	$ (1.15)
NGLs ($/Bbl)	13.43	14.01	(0.58)
Oil ($/Bbl)	41.38	46.64	(5.26)
Total average prices ($/Mcfe)	2.74	4.06	(1.32)
Average Sales Price (including firm transportation)			
Natural gas ($/Mcf)	$ 1.12	$ 2.30	$ (1.18)
NGLs ($/Bbl)	13.60	14.01	(0.41)
Oil ($/Bbl)	36.74	45.48	(8.74)
Total average prices ($/Mcfe)	1.82	3.35	(1.53)
Average Sales Price (including cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$ 1.86	$ 3.05	$ (1.19)
NGLs ($/Bbl)	13.43	14.01	(0.58)
Oil ($/Bbl)	41.38	46.64	(5.26)
Total average prices ($/Mcfe)	2.42	3.82	(1.40)

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 $1.2 million and $9.5 million for the three months ended June 30, 2016 and 2015, 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.

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 information about certain of our expenses for the three months ended June 30, 2016 and 2015:

	Three Months Ended		
	June 30,		
	2016	2015	Change
Operating Expenses (in thousands):			
Lease operating	$ 2,248	$ 3,589	$ (1,341)
Transportation, gathering and compression	28,254	22,634	5,620
Production and ad valorem taxes	2,051	3,078	(1,027)
Depreciation, depletion and amortization	20,949	60,641	(39,692)
General and administrative	10,402	12,717	(2,315)

	Three Months Ended		
	June 30,		
	2016	2015	Change
Operating Expenses per Mcfe:			
Lease operating	$ 0.10	$ 0.20	$ (0.10)
Transportation, gathering and compression	1.32	1.25	0.07
Production and ad valorem taxes	0.10	0.17	(0.07)
Depreciation, depletion and amortization	0.98	3.35	(2.37)
General and administrative	0.48	0.70	(0.22)

Lease operating expense was $2.2 million in the three months ended June 30, 2016 compared to $3.6 million in the three months ended June 30, 2015. The decrease of $1.4 million is attributable to reduced personnel costs and additional cost-cutting measures during the three months ended June 30, 2016, as compared to the three months ended June 30, 2015. 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 $28.3 million during the three months ended June 30, 2016 compared to $22.6 million in the three months ended June 30, 2015. These third-party costs were higher in the three months ended June 30, 2016 due primarily to an upward revision of prior estimates of amounts due to a non-operated partner based on additional information received during the period totaling $5.8 million and increased firm transportation expenses. The following table details our transportation, gathering and compression expenses for the three months ended June 30, 2016 and 2015:

Three Months Ended

	June 30, 2016	2015	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	$ 11,176	$ 7,630	$ 3,546
Processing and fractionation	8,320	7,373	947
Liquids transportation and stabilization	1,937	2,681	(744)
Marketing	6	569	(563)
Firm transportation	6,815	4,381	2,434
	$ 28,254	$ 22,634	$ 5,620

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $2.1 million in the three months ended June 30, 2016 compared to $3.1 million in the three months ended June 30, 2015. Production and ad valorem taxes decreased from the three months ended June 30, 2015 to the three months ended June 30, 2016 due to a change in our estimated accrual rate based on recent historical experience.

Depreciation, depletion and amortization was approximately $20.9 million in the three months ended June 30, 2016 compared to $60.6 million in the three months ended June 30, 2015. The decrease in the three months ended June 30, 2016 when compared to the three months ended June 30, 2015 is due to the decrease in proved property costs from impairment charges taken during 2015 and 2016 . On a per Mcfe basis, DD&A decreased to $0.98 in the three months ended June 30, 2016 from $3.35 in the three months ended June 30, 2015, which was predominantly driven by the lower depletion rate resulting from our reduced proved property costs.

General and administrative expense was $10.4 million for the three months ended June 30, 2016 compared to $12.7 million for the three months ended June 30, 2015. The decrease of $2.3 million during the three months ended June 30, 2016 when compared to three months ended June 30, 2015 was primarily due to lower salaries and benefits associated with reduced headcount as of June 30, 2016 as compared to June 30, 2015.

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, 2016 and 2015:

	Three Months Ended June 30,		
	2016	2015	Change
Other Operating Expenses (in thousands):			
Brokered natural gas and marketing expense	$ 2,160	$ 10,795	$ (8,635)
Exploration	17,444	6,243	11,201
Rig termination and standby	1,292	366	926
Accretion of asset retirement obligations	89	399	(310)
(Gain) loss on sale of assets	(1,024)	(5,553)	4,529

Brokered natural gas and marketing expense was $2.2 million for the three months ended June 30, 2016 compared to $10.8 million for the three months ended June 30, 2015. 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.

Exploration expense was $17.4 million for the three months ended June 30, 2016 compared to $6.2 million for the three months ended June 30, 2015. The following table details our exploration-related expenses for the three months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		
	2016	2015	Change
Exploration Expenses (in thousands):			
Geological and geophysical	$ 395	$ 15	$ 380
Delay rentals	7,178	1,784	5,394
Impairment of unproved properties	9,360	4,420	4,940
Dry hole and other	511	24	487
	$ 17,444	$ 6,243	$ 11,201

Delay rentals were $7.2 million for the three months ended June 30, 2016 compared to $1.8 million for the three months ended June 30, 2015. The increase in delay rental expenses relates primarily to converting future lump-sum extension payments into annual delay rentals.

Impairment of unproved properties was $9.4 million for the three months ended June 30, 2016 compared to $4.4 million for the three months ended June 30, 2015. We assess individually significant unproved properties for impairment and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors, including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. 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 was $1.3 million related primarily to standby costs that we incurred from temporarily suspending our drilling operations for a portion of the period. For the three months ended June 30, 2015, rig termination and standby expenses were $0.4 million related primarily to rig termination expenses.

Accretion of asset retirement obligations was $0.1 million for the three months ended June 30, 2016 compared to $0.4 million for three months ended June 30, 2015. The decrease in accretion expense primarily relates to the sale of our conventional assets and liabilities during the three months ended June 30, 2016 .

Other Income (Expense)

Gain (loss) on derivative instruments was ($29.6) million for the three months ended June 30, 2016 compared to ($3.5) million for the three months ended June 30, 2015. Cash receipts were approximately $12.9 million and $8.5 million for derivative instruments that settled during the three months ended June 30, 2016 and June 30, 2015, respectively.

Interest expense, net was $12.4 million for the three months ended June 30, 2016 compared to $14.4 million for three months ended June 30, 2015. The decrease in interest expense was due to a lower interest rate on our Notes and reduced interest from the repurchase of long term debt during the three months ending June 30, 2016 compared to the three months ended June 30, 2015.

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 Notes on the open market for $14.3 million with cash on hand. The outstanding 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.

Income tax expense (benefit) was $0.0 million for the three months ended June 30, 2016 compared to income tax benefit of ($16.4) million for the three months ended June 30, 2015. The reduction of income tax benefit recorded for the three months ended June 30, 2016 as compared to the similar period of the prior year was due to the Company recording a higher valuation allowance due to its recurring pre-tax losses.

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

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

The following table illustrates the revenue attributable to natural gas, NGLs and oil sales for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,		
	2016	2015	Change
Revenues (in thousands)			
Natural gas sales	$51,929	$54,584	$(2,655)
NGL sales	15,853	17,127	(1,274)
Oil sales	18,607	39,887	(21,280)
Total revenues	$86,389	$111,598	$(25,209)

Our production grew by approximately 7.4 Bcfe for the six months ended June 30, 2016 over the same period in 2015 as we placed new wells into production, partially offset by natural decline and voluntary curtailment of our operated production. Our production for the six months ended June 30, 2016 and 2015 is set forth in the following table:

Six Months Ended

	June 30,		
	2016	2015	Change
Production:			
Natural gas (MMcf)	28,985.8	20,251.2	8,734.6
NGL sales (Mbbls)	1,199.6	1,077.2	122.4
Oil sales (Mbbls)	600.5	953.6	(353.1)
Total (MMcfe)	39,786.4	32,436.0	7,350.4
Average daily production volume:			
Natural gas (Mcf/d)	159,263	111,885	47,378
NGL sales (Bbls/d)	6,591	5,951	640
Oil sales (Bbls/d)	3,299	5,269	(1,970)
Total (Mcfe/d)	218,603	179,204	39,399

During the period, 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 the six months ended June 30, 2016.

Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the six months ended June 30, 2016 was $2.63 per Mcfe compared to $3.73 per Mcfe during the six months ended June 30, 2015. 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, 2016 and 2015 are shown below:

	Six Months Ended June 30,		
	2016	2015	Change
Average Sales Price (excluding cash settled derivatives)			
Natural gas ($/Mcf)	$1.79	$2.70	$(0.91)
NGLs ($/Bbl)	13.22	15.90	(2.68)
Oil ($/Bbl)	30.99	41.83	(10.84)
Total average prices ($/Mcfe)	2.17	3.44	(1.27)
Average Sales Price (including cash settled derivatives)			
Natural gas ($/Mcf)	$2.60	$3.37	$(0.77)
NGLs ($/Bbl)	13.43	15.90	(2.47)
Oil ($/Bbl)	43.52	42.56	0.96
Total average prices ($/Mcfe)	2.96	3.89	(0.93)
Average Sales Price (including firm transportation)			
Natural gas ($/Mcf)	$1.35	$2.44	$(1.09)
NGLs ($/Bbl)	13.22	15.90	(2.68)
Oil ($/Bbl)	30.99	41.83	(10.84)
Total average prices ($/Mcfe)	1.85	3.28	(1.43)
Average Sales Price (including cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$2.16	$3.12	$(0.96)
NGLs ($/Bbl)	13.43	15.90	(2.47)
Oil ($/Bbl)	43.52	42.56	0.96
Total average prices ($/Mcfe)	2.63	3.73	(1.10)

During the period, 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 natural gas liquids prices by $0.37 per Bbl for the six months ended June 30, 2016.

Brokered natural gas and marketing revenue was $10.3 million and $6.7 million for the six months ended June 30, 2016 and 2015, 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.

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 information about certain of our expenses for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,		
	2016	2015	Change
Operating Expenses (in thousands)			
Lease operating	$4,925	$6,935	$(2,010)
Transportation, gathering and compression	51,391	35,085	16,306
Production and ad valorem taxes	(233)	5,178	(5,411)
Depreciation, depletion and amortization	36,062	103,073	(67,011)
General and administrative	21,676	24,660	(2,984)

	Six Months Ended June 30, 2016	2015	Change
Operating Expenses per Mcfe:			
Lease operating	$0.12	$0.21	$(0.09)
Transportation, gathering and compression	1.29	1.08	0.21
Production and ad valorem taxes	(0.01)	0.16	(0.17)
Depreciation, depletion and amortization	0.91	3.18	(2.27)
General and administrative	0.54	0.76	(0.22)

Lease operating expense was $4.9 million in the six months ended June 30, 2016 compared to $6.9 million in the six months ended June 30, 2015. The decrease of $2.0 million is attributable to reduced personnel costs and additional cost-cutting measures during the six months ended June 30, 2016, as compared to the six months ended June 30, 2015. 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 $51.4 million during the six months ended June 30, 2016 compared to $35.1 million in the six months ended June 30, 2015. These third-party costs were higher in the six months ended June 30, 2016 due to our production growth where we have third party gathering and compression agreements and increased processing costs associated with our higher liquids production, and increased firm transportation expenses. In addition, we revised our estimate of amounts due to a non-operated partner for such costs based on additional information received during the period, resulting in an increase of $5.8 million. The following table details our transportation, gathering and compression expenses for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30, 2016	2015	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	$19,312	$10,868	$8,444
Processing and fractionation	15,862	13,446	2,416
Liquids transportation and stabilization	3,338	4,537	(1,199)
Marketing	—	1,115	(1,115)
Firm transportation	12,879	5,119	7,760
	$51,391	$35,085	$16,306

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were ($0.2) million in the six months ended June 30, 2016 compared to $5.2 million in the six months ended June 30, 2015. Production and ad valorem taxes decreased from the six months ended June 30, 2015 to the six months ended June 30, 2016 due to a reduction in our estimated accruals of approximately $4 million based on recent historical experience and additional information received during the period.

Depreciation, depletion and amortization was approximately $36.1 million in the six months ended June 30, 2016 compared to $103.1 million in the six months ended June 30, 2015. The decrease in the six months ended June 30, 2016 when compared to the six months ended June 30, 2015 is due to the decrease in proved property costs from impairment charges taken during 2015 and 2016. On a per Mcfe basis, DD&A decreased to $0.91 in the six months ended June 30, 2016 from $3.18 in the six months ended June 30, 2015, which was predominantly driven by the lower depletion rate resulting from our reduced proved property costs.

General and administrative expense was $21.7 million for the six months ended June 30, 2016 compared to $24.7 million for the six months ended June 30, 2015. The decrease of $3.0 million during the six months ended June 30, 2016 when compared to six months ended June 30, 2015 was primarily due to lower salaries and benefits associated with reduced headcount as of June 30, 2016 as compared to June 30, 2015.

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, 2016 and 2015:

	Six Months Ended June 30,		
	2016	2015	Change
Other Operating Expenses (in thousands):			
Brokered natural gas and marketing expense	$11,562	$10,795	$767
Exploration	33,100	19,696	13,404
Rig termination and standby	3,955	7,423	(3,468)
Impairment of proved oil and gas properties	17,665	—	17,665
Accretion of asset retirement obligations	175	785	(610)
(Gain) loss on sale of assets	(1,046)	(5,473)	4,427

Brokered natural gas and marketing expense was $11.6 million for the six months ended June 30, 2016 compared to $10.8 million for the six months ended June 30, 2015. 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.

Exploration expense was $33.1 million for the six months ended June 30, 2016 compared to $19.7 million for the six months ended June 30, 2015. The following table details our exploration-related expenses for the six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,		
	2016	2015	Change
Exploration Expenses (in thousands):			
Geological and geophysical	$415	$131	$284
Delay rentals	13,417	13,492	(75)
Impairment of unproved properties	18,720	6,044	12,676
Dry hole and other	548	29	519
	$33,100	$19,696	$13,404

Impairment of unproved properties was $18.7 million for the six months ended June 30, 2016 compared to $6.0 million for the six months ended June 30, 2015. We assess individually significant unproved properties for impairment and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors, including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. 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 was $4.0 million related primarily to standby costs that we incurred from temporarily suspending our drilling operations for a portion of the period. For the six months ended June 30, 2015, rig termination and standby expenses were $7.4 million related primarily to rig termination expenses.

Impairment of proved oil and gas properties was $17.7 million for the six months ended June 30, 2016 related to our properties in the Marcellus Shale. An analysis of proved properties determined the future undiscounted cash flows were less than the carrying value for certain asset groupings. An impairment expense was recognized for these asset groupings based on the difference between the fair market value and carrying value of the asset groupings. No impairment of proved oil and gas properties was recognized for the six months ended June 30, 2015.

Accretion of asset retirement obligations was $0.2 million for the six months ended June 30, 2016 compared to $0.8 million for six months ended June 30, 2015. The decrease in accretion expense primarily relates to the classification of our conventional assets and liabilities to assets held for sale as of June 30, 2016.

Other Income (Expense)

Gain (loss) on derivative instruments was ($19.0) million for the six months ended June 30, 2016 compared to $7.8 million for the six months ended June 30, 2015. Cash receipts were approximately $31.3 million and $14.4 million for derivative instruments that settled during the six months ended June 30, 2016 and June 30, 2015, respectively.

Interest expense, net was $25.9 million for the six months ended June 30, 2016 compared to $28.4 million for six months ended June 30, 2015. The decrease in interest expense was due to a lower interest rate on our Notes and reduced interest from the repurchase of long term debt during the six months ending June 30, 2016 compared to the six months ended June 30, 2015.

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 Notes on the open market for $23.4 million during such period. The outstanding 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.

Income tax expense (benefit) was $0.5 million for the six months ended June 30, 2016 compared to income tax benefit of ($34.0) million for the six months ended June 30, 2015. The reduction of income tax benefit recorded for the six months ended June 30, 2016 as compared to the similar period of the prior year was due to the Company recording a higher valuation allowance due to its recurring pre-tax losses.

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

Net cash provided by (used in) operations in the six months ended June 30, 2016 was ($17.3) million compared to $49.5 million in the six months ended June 30, 2015. The decrease in cash provided from operating activities reflects the decrease 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, 2016 was $29.2 million compared to $291.9 million in the six months ended June 30, 2015.

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

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

During the six months ended June 30, 2015, we:

- spent $327.9 million on capital expenditures for oil and gas properties;
- spent $1.3 million on property and equipment; and

- received $37.3 million of proceeds relating to the sale of gathering facilities and equipment.

Net cash provided by (used in) financing activities in the six months ended June 30, 2016 was ($23.9) million compared to $432.4 million in the six months ended June 30, 2015.

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

- purchased outstanding Notes with face value of $39.5 million for $23.4 million.

During the six months ended June 30, 2015, we:

- issued shares of common stock in a private placement transaction for proceeds to us totaling approximately $434.2 million, net of $5.7 million of issuance costs.

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, the net proceeds we received from our recently completed common stock offering, operating cash flow and available borrowings under our Revolving Credit Facility will be adequate to meet our capital and operating requirements for 2016.

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, borrowings under our Revolving Credit Facility, and the net proceeds we received from our recently completed common stock offering 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, 2016, we were in compliance with all of our debt covenants under our Revolving Credit Facility and 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 remain at current levels for longer than we expect, or fall 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, 2016, excluding discount, totaled $510.5 million and at December 31, 2015 totaled $550.0 million. We redeemed all of the outstanding Senior PIK Notes on July 13, 2015 for approximately $510.7 million, including outstanding principal balance, a make-whole premium and accrued interest. (See Note 7—Debt).

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior notes due 2023 (the “Notes”) 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 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 $510.5 million to finance the redemption of all of our outstanding 12.0% Senior PIK notes due 2018. We intend to use 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 Notes in open market purchases for $23.4 million. The outstanding principal of the 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 contains governing the Notes 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 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 Notes to be enforceable, and certain events of bankruptcy or insolvency. We were in compliance with all covenants at June 30, 2016.

We have also entered into a $500 million Revolving Credit Facility, which matures on January 15, 2018 and is governed by a Credit Agreement that includes customary affirmative and negative covenants. The borrowing base under our Revolving Credit Facility is $125 million. After giving effect to our outstanding letters of credit issued, totaling $27.8 million, we had available borrowing capacity under our Revolving Credit Facility of $97.2 million at June 30, 2016. The borrowing base under our Revolving Credit Facility is scheduled to be redetermined semi-annually (in April and October) with our next redetermination expected to be completed by October 2016.

On February 24, 2016, we amended the Credit Agreement governing our Revolving Credit Facility to, among other things, adjust our 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 Credit Agreement also 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 us to, within 60 days of the effectiveness of the amendment, execute and deliver additional mortgages on our oil and gas properties that include at least 90% of our proved reserves.

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, 2016, we had entered into the following derivative contracts:

Natural Gas Derivatives

Description	Volume (MMBtu/d)	Production Period	Weighted Average Price ($/MMBtu)
Natural Gas Swaps:			
	65,000	July 2016 – December 2016	$ 3.28
	10,000	January 2017 – December 2017	$ 2.98
Natural Gas Collars:			
Floor purchase price (put)	30,000	July 2016 – December 2017	$ 3.00
Ceiling sold price (call)	30,000	July 2016 – December 2017	$ 3.50
Floor purchase price (put)	50,000	January 2017 – December 2017	$ 3.00
Ceiling sold price (call)	50,000	January 2017 – December 2017	$ 3.20
Floor purchase price (put)	20,000	January 2017 – December 2017	$ 2.75
Ceiling sold price (call)	20,000	January 2017 – December 2017	$ 3.29
Floor purchase price (put)	30,000	January 2017 – December 2017	$ 2.50
Ceiling sold price (call)	30,000	January 2017 – December 2017	$ 3.03
Natural Gas Three-way Collars:			
Floor purchase price (put)	40,000	July 2016 – December 2016	$ 2.90
Ceiling sold price (call)	40,000	July 2016 – December 2016	$ 3.24
Floor sold price (put)	40,000	July 2016 – December 2016	$ 2.35
Floor purchase price (put)	30,000	January 2017 – December 2017	$ 2.75
Ceiling sold price (call)	30,000	January 2017 – December 2017	$ 3.57
Floor sold price (put)	30,000	January 2017 – December 2017	$ 2.25
Natural Gas Call/Put Options:			
Put sold	16,800	July 2016 – December 2016	$ 2.75
Call sold	40,000	January 2018 – December 2018	$ 3.75

Oil Derivatives

Description	Volume (Bbls/d)	Production Period	Weighted Average Price ($/Bbl)
Oil Swaps:			
	850	July 2016 – December 2016	$ 45.55
Oil Three-way Collars:			
Floor purchase price (put)	1,000	July 2016 – December 2016	$ 60.00
Ceiling sold price (call)	1,000	July 2016 – December 2016	$ 70.10
Floor sold price (put)	1,000	July 2016 – December 2016	$ 45.00
Floor purchase price (put)	2,000	January 2017 – September 2017	$ 46.00
Ceiling sold price (call)	2,000	January 2017 – September 2017	$ 59.50
Floor sold price (put)	2,000	January 2017 – September 2017	$ 38.00

Floor purchase price (put)	2,000	January 2017 – December 2017	$ 46.00
Ceiling sold price (call)	2,000	January 2017 – December 2017	$ 60.00
Floor sold price (put)	2,000	January 2017 – December 2017	$ 38.00
Oil Call/Put Options:			
Call sold	1,000	January 2018 – December 2018	$ 50.00

NGL Derivatives

Description	Volume (Gal/d)	Production Period	Weighted Average Price ($/Gal)
Propane Swaps:			
	42,000	July 2016 – December 2016	$ 0.46
	10,500	July 2016 – September 2016	$ 0.46

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

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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 NA. We believe both institutions currently are an acceptable credit risk. As of June 30, 2016, 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, 2016. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $20.3 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $21.3 million. A hypothetical 10 percent decrease in future oil prices would increase future earnings related to derivatives by $5.2 million. Similarly, a hypothetical 10 percent increase in future oil prices would decrease future earnings related to derivatives by $6.0 million.

Subsequent to June 30, 2016, we entered into the following derivative instruments to mitigate our exposure to natural gas and oil prices:

Description	Volume (MMbtu/d)	Production Period	Weighted Average Price ($/MMbtu)	
Natural Gas Collars:				
Floor purchase price (put)	20,000	January 2017 – December 2018	$	2.90
Ceiling sold price (call)	20,000	January 2017 – December 2018	$	3.25
Floor purchase price (put)	30,000	January 2018 – December 2018	$	2.75
Ceiling sold price (call)	30,000	January 2018 – December 2018	$	3.28

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. As a result of the increase in commodity forward prices during the second quarter of 2016, we increased our 2016 capital expenditure budget by approximately 17 percent, or $28 million, from $167.8 million to $196 million. We expect to fund our capital expenditures for 2016 with cash generated by operations, the net proceeds we received from our recently completed common stock offering, borrowings under our Revolving Credit Facility, proceeds from asset sales, and proceeds from additional debt or equity offerings. 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, 2016 and December 31, 2015, our total debt, excluding debt discount, and capitalization were as follows (in millions):

	June 30, 2016	December 31, 2015
Senior Unsecured Notes	510.5	550.0
Stockholders Equity	510.2	620.6
Total Capitalization	1,020.7	1,170.6

During the six months ended June 30, 2016, the Company repurchased and retired $39.5 million of the outstanding Notes on the open market for $23.4 million.

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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, 2016 and December 31, 2015, 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, 2016 reflects accrued interest payable of $20.9 million, compared to $23.8 million as of December 31, 2015.

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, 2016, we had $510.5 million as compared to $550.0 million as of December 31, 2015, 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.

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior 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 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 Senior PIK Notes on July 13, 2015. We intend to use the remaining net proceeds to fund our capital expenditure plan and for general corporate purposes.

We have also entered into a $500 million senior secured revolving bank credit facility, which matures in 2018. 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 semiannual redeterminations. The borrowing base under our Revolving Credit Facility is $125 million. After giving effect to our outstanding letters of credit, totaling $27.8 million, we had available borrowing capacity under our Revolving Credit Facility of $97.2 million at June 30, 2016. The next borrowing base redetermination is expected to be completed by October 2016.

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 2016 to continue to be a function of supply and demand.

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. 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 Revolving Credit Facility and the Indentures.

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 loss from operations to Adjusted EBITDAX for the periods presented:

	Three Months Ended		Six Months Ended	
	June 30, 2016	2015	June 30, 2016	2015
Net loss	$(73,011)	$(41,970)	$(113,698)	$(76,073)
Depreciation, depletion and amortization	20,949	60,641	36,062	103,073
Exploration expense	17,444	6,243	33,100	19,696
Rig termination and standby	1,292	366	3,955	7,423
Impairment of proved oil and gas properties	—	—	17,665	—
Stock-based compensation	2,226	1,410	3,701	2,157
Accretion of asset retirement obligations	89	399	175	785
(Gain) loss on derivative instruments	29,596	3,523	19,046	(7,848)
Net cash receipts (payments) on settled derivatives	12,880	8,457	31,258	14,422
Interest expense, net	12,439	14,401	25,900	28,422
(Gain) loss on sale of assets	(1,024)	(5,553)	(1,046)	(5,473)
Gain on early extinguishment of debt	(5,825)	—	(14,489)	—
Other (income) expense	2	2	141	(400)
Income tax (benefit) expense	—	(16,412)	540	(33,991)
Adjusted EBITDAX	$17,057	$31,507	$42,310	$52,193

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, 2015 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 79% of our December 31, 2015 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 notes due 2023 at an issue price of 97.903% of the principal amount of the Notes, plus accrued and unpaid interest, if any. At June 30, 2016, the cash interest rate with respect to the 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, 2016, the borrowing base was $125 million and we had no outstanding borrowings. After giving effect to our outstanding letters of credit, totaling $27.8 million, we had available borrowing capacity under the Revolving Credit Facility of $97.2 million at June 30, 2016.

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, 2016, 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 12—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, you should carefully consider the factors discussed in "Risk Factors" in our Annual Report on Form 10-K filed with the SEC on March 4, 2016, 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.

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.

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, 2016	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	Form of Performance Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on April 26, 2016).
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.