CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) AND MANAGEMENT'S DISCUSSION AND ANALYSIS

Ascent Resources Utica Holdings, LLC

As of September 30, 2017 and December 31, 2016, and for the Three and Nine Months Ended September 30, 2017 and 2016.

ASCENT RESOURCES UTICA HOLDINGS, LLC
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ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2017	December 31, 2016
	($ in thousands)	
Current Assets:		
Cash and cash equivalents	$ 248,646	$ 268,493
Accounts receivable – natural gas, oil and NGL sales	117,832	75,350
Accounts receivable – joint interest and other	14,173	3,224
Short-term derivative assets	13,766	—
Other current assets	2,957	1,067
Total Current Assets	397,374	348,134
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	4,294,769	3,638,619
Other property and equipment	19,618	19,508
Less: accumulated depreciation, depletion and amortization	(580,754)	(370,955)
Property and Equipment, net	3,733,633	3,287,172
Other Assets:		
Deposits on pipeline transportation	3,478	151,193
Long-term derivative assets	1,076	—
Other long-term assets	16,437	6,959
Total Assets	$ 4,151,998	$ 3,793,458
Current Liabilities:		
Accounts payable	$ 55,136	$ 37,916
Revenue payable	49,739	34,167
Accrued interest	78,189	11,829
Short-term derivative liabilities	4,738	74,489
Acquisition obligation	84,371	47,121
Other current liabilities	206,107	114,435
Total Current Liabilities	478,280	319,957
Long-Term Liabilities:		
Long-term debt, net	1,560,564	1,325,325
Long-term derivative liabilities	7,354	19,414
Acquisition obligation	—	50,824
Other long-term liabilities	11,620	10,755
Total Long-Term Liabilities	1,579,538	1,406,318
Commitments and contingencies (Note 8)		
Member’s Equity	2,094,180	2,067,183
Total Liabilities and Member’s Equity	$ 4,151,998	$ 3,793,458

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	($ in thousands)			
Revenues:				
Natural gas	$ 177,646	$ 73,179	$ 457,797	$ 167,590
Oil	25,609	16,876	87,409	50,880
NGL	17,047	7,556	53,474	25,719
Commodity derivative (loss) gain	(17,248)	9,338	105,185	(8,753)
Total Revenues	203,054	106,949	703,865	235,436
Operating Expenses:				
Lease operating expenses	10,174	3,010	24,650	19,622
Gathering, processing and transportation expenses	77,660	44,483	227,053	140,857
Production and ad valorem taxes	3,467	1,909	9,714	5,995
Exploration expenses	22,936	60,596	137,868	124,921
General and administrative expenses	1,239	1,491	3,804	5,446
General and administrative expenses – related party	8,182	9,136	26,560	23,375
Litigation settlement benefit	—	—	—	(4,147)
Natural gas and oil depreciation, depletion and amortization	80,034	61,890	208,405	170,798
Depreciation and amortization of other assets	487	461	1,435	1,391
Impairment of other property and equipment	—	—	—	2,222
Total Operating Expenses	204,179	182,976	639,489	490,480
(Loss) Income From Operations	(1,125)	(76,027)	64,376	(255,044)
Other (Expense) Income:				
Interest expense, net	(23,668)	(23,528)	(46,517)	(76,273)
Acquisition obligation accretion expense	(967)	(2,301)	(3,531)	(8,509)
Change in fair value of embedded derivative	(633)	—	(18,603)	8,241
(Losses) gains on purchases or exchanges of debt	—	(336)	(114,052)	304,817
Other income	489	299	1,383	1,752
Total Other (Expense) Income	(24,779)	(25,866)	(181,320)	230,028
Net Loss	$ (25,904)	$ (101,893)	$ (116,944)	$ (25,016)

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENT OF MEMBER'S EQUITY
(Unaudited)

	Nine Months Ended September 30, 2017
	($ in thousands)
Balance, beginning of period	$ 2,067,183
Contributions from Member	132,000
Contribution of debt held by Member	11,942
Incentive unit compensation	(1)
Net loss	(116,944)
Balance, end of period	$ 2,094,180

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
	2017	2016
	($ in thousands)	
Cash Flows from Operating Activities:		
Net loss	$ (116,944)	$ (25,016)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	209,840	172,189
Impairment of other property and equipment	—	2,222
Change in fair value of commodity derivatives	(96,653)	16,245
Impairment of natural gas and oil unproved properties	136,738	111,145
Non-cash interest expense	—	74,888
Acquisition obligation accretion expense	3,531	8,509
Change in fair value of embedded derivative	18,603	(8,241)
Losses (gains) on purchases or exchanges of debt	43,053	(305,154)
Litigation settlement benefit	—	(4,147)
Other	(2)	255
Changes in assets and liabilities:		
Increase in accounts receivable and other assets	(54,221)	(18,105)
Increase in accounts payable, liabilities and other	84,933	1,581
Net Cash Provided by Operating Activities	228,878	26,371
Cash Flows from Investing Activities:		
Drilling and completion costs	(434,087)	(201,003)
Acquisitions of proved and unproved natural gas and oil properties	(249,646)	(315,530)
Proceeds from divestitures of unproved natural gas and oil properties	—	16,664
Proceeds from sale of other property and equipment	13	—
Deposit on natural gas and oil property acquisition	(6,200)	—
Reductions in (additions to) deposits on pipeline transportation	147,715	(35,394)
Additions to other property and equipment	(140)	(715)
Net Cash Used in Investing Activities	(542,345)	(535,978)
Cash Flows from Financing Activities:		
Proceeds from issuance of long-term debt, net	1,466,250	—
Repayment of debt	(1,290,264)	—
Cash paid for debt issuance costs	(14,366)	(7,846)
Repayment of note payable to third party	—	(37,170)
Contributions from Member	132,000	677,229
Net Cash Provided by Financing Activities	293,620	632,213
Net (Decrease) Increase in Cash and Cash Equivalents	(19,847)	122,606
Cash and Cash Equivalents, Beginning of Period	268,493	84,187
Cash and Cash Equivalents, End of Period	$ 248,646	$ 206,793
Supplemental disclosures of cash flow information:		
Interest paid, net of capitalized interest and interest paid in kind	$ 7,625	$ 273
Supplemental disclosures of significant non-cash investing and financing activities:		
Increase (decrease) in accrued capital expenditures	$ 54,028	$ (56,056)
Contribution of debt held by Member	$ 11,942	$ —
Contributions from Member - non-cash issuance of Parent equity	$ —	$ 237,122

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Consolidation

The accompanying unaudited condensed consolidated financial statements and notes of Ascent Resources Utica Holdings, LLC (ARUH) and together with its wholly-owned subsidiaries (collectively, "the Company") were prepared in accordance with United States generally accepted accounting principles (US GAAP). ARUH is a wholly-owned subsidiary of Ascent Resources Operating, LLC (the Member), which is an indirect, wholly-owned subsidiary of Ascent Resources, LLC (the Parent). The Parent is majority owned by investment funds controlled by The Energy & Minerals Group (EMG) and First Reserve Corporation. Intercompany accounts and balances have been eliminated. Certain disclosures normally included in consolidated financial statements prepared in accordance with US GAAP have been omitted. The unaudited condensed consolidated financial statements and notes should be read in conjunction with the Company's audited consolidated financial statements and notes for the year ended December 31, 2016.

The unaudited condensed consolidated financial statements furnished in this report reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods. All such adjustments are of a normal recurring nature. The results for any interim period are not necessarily indicative of the expected results for the entire year.

The Company operates in one industry segment, which is the exploration, development and production of natural gas, oil and natural gas liquids (NGL). The Company's current operational activities and its consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long-lived assets located outside the U.S.

Risks and Uncertainties

A substantial or extended decline in natural gas, oil and NGL prices could have a material impact on the Company's financial position, results of operations, cash flows and quantities of natural gas, oil and NGL reserves that may be economically produced. Furthermore, in a low commodity price environment the Company's ability to generate positive operating cash flows, maintain its natural gas, oil and NGL production and reserves, sell assets, or take any other action to improve its liquidity is subject to risks and uncertainties that exist in its industry, some of which the Company may not be able to anticipate at this time or control. Other risks and uncertainties that could affect the Company include, but are not limited to, counterparty credit risk, access to capital markets, regulatory risk and its ability to meet financial ratios and other covenants in its debt agreements.

Accounting Estimates

The preparation of condensed consolidated financial statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures in the condensed consolidated financial statements. Actual amounts could differ from these estimates.

Estimates of natural gas, oil and NGL reserves and their values, future production rates and future costs and expenses are the most significant of the Company's estimates. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, commodity prices, operating costs and other factors. These revisions could materially affect the Company's financial statements. The volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. Changes in natural gas, oil or NGL prices could result in actual results differing significantly from the Company's estimates.

Concentration of Credit Risk

The Company is subject to credit risk resulting from the concentration of its natural gas, oil and NGL receivables. The following table provides the concentration of sales to individual purchasers that constitute 10% or more of the Company's revenues, before the effects of derivatives, for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Tenaska Marketing Ventures	19%	47%	25%	48%
Sequent Energy Management, L.P.	30%	12%	25%	—
Marathon Petroleum Company, L.P.	—	14%	—	18%
DTE Energy Trading, Inc.	—	10%	—	—

The Company does not believe the loss of any single purchaser would materially impact its operating results, as natural gas, oil and NGL are fungible products with well-established markets and numerous purchasers in the Company's operating region.

Adopted and Recently Issued Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The standard's core principle is that an entity shall recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The new standard will also result in enhanced revenue disclosures, provide guidance for transactions that were not previously addressed comprehensively and improve guidance for multiple-element arrangements. In August 2015, the FASB issued ASU 2015-14, which deferred the effective date of the new revenue standard by one year. This amendment is effective for periods beginning after December 15, 2017, though the FASB has permitted entities to adopt one year earlier if they chose (i.e., the original effective date). The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the consolidated financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. In December 2016, the FASB issued ASU 2016-20 which updates narrow aspects of the guidance issued in ASU 2014-09. The Company is currently evaluating the impact of this ASU on its consolidated financial statements and working to identify any potential differences that would result from applying the requirements of the ASU to existing contracts and current accounting policies and practices. This evaluation includes the review of contracts for each revenue stream identified within the Company's business. The Company is still in the process of determining whether or not it will use the retrospective method or the modified retrospective approach for implementation.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*. The amendments in this update require, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018. The Company is currently evaluating the impact of this ASU on its consolidated financial statements and disclosures.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments*. This guidance addresses eight specific cash flow issues. This amendment is effective for periods beginning after December 15, 2017, with early adoption permitted. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and does not anticipate it will have a material effect on its consolidated financial statements and disclosures.

In November 2016, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*. This update is intended to reduce diversity in practice by adding or clarifying guidance on classification and presentation of changes in restricted cash on the statement of cash flows. This amendment is effective for annual and interim periods beginning after December 15, 2017, with early adoption permitted, and should be applied retrospectively to all periods presented. The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements and does not anticipate it will have a material effect on its consolidated financial statements and disclosures.

In January 2017, the FASB issued ASU 2017-01 - *Business Combinations (Topic 805): Clarifying the Definition of a Business*. This update clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This amendment is effective for annual periods beginning after December 15, 2018 and interim periods within annual periods beginning after December 15, 2019. This guidance is applicable to business combinations completed after the adoption of the guidance. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and disclosures.

In May 2017, the FASB issued ASU 2017-09 - *Stock Compensation (Topic 718): Scope of Modification Accounting*. This update clarifies the guidance for changes to the terms or conditions of share-based payment awards which require an entity to apply modification accounting in Topic 718. This amendment is effective for annual and interim periods beginning after December 15, 2017, with early adoption permitted, and should be applied prospectively to awards modified on or after the adoption date without revising the amounts reported from prior periods. The Company is in the process of evaluating the impact of this guidance on its consolidated financial statements and does not anticipate it will have a material effect on its consolidated financial statements and disclosures.

Subsequent Events

The Company evaluated its September 30, 2017 condensed consolidated financial statements for subsequent events through November 13, 2017, the date the unaudited condensed consolidated financial statements were available to be issued, and such events are noted herein.

2. Property and Equipment

Net property and equipment included the following:

	September 30, 2017	December 31, 2016
	($ in thousands)	
Proved natural gas and oil properties	$ 3,144,826	$ 2,094,137
Unproved natural gas and oil properties	1,149,943	1,544,482
Other property and equipment	19,618	19,508
Total Property and Equipment	4,314,387	3,658,127
Accumulated depreciation, depletion and amortization	(580,754)	(370,955)
Property and Equipment, net	$ 3,733,633	$ 3,287,172

3. Acquisitions

In August 2017, Utica Minerals Development, LLC (UMD) and the Company acquired approximately 10,400 net acres in the Utica Shale in Ohio from an unaffiliated seller (the Acquisition Properties) for a purchase price of $98.2 million, subject to customary post-closing adjustments. At closing, the Company received an undivided 25% interest in the Acquisition Properties for $33.4 million with UMD receiving the remaining undivided 75% interest in the Acquisition Properties. The Company funded this acquisition with cash on hand and $32.0 million that was contributed from the Member. The Acquisition Properties consisted of unproved leasehold and was accounted for as an asset acquisition.

Pursuant to an agreement between the Company and UMD (the Earn-In Agreement), the Company may earn an additional undivided 25% interest in the Acquisition Properties from UMD by drilling and operating a designated set of wells on the Acquisition Properties and carrying 100% of UMD's drilling and completion costs (carried costs) of approximately $22.0 million. Upon the Company's full payment of the UMD carried costs, each party will own an undivided 50% interest in the Acquisition Properties. In accordance with the Earn-In Agreement, the Company will have the right to pay the outstanding balance of the carry, and any prepayment penalty (if applicable), at any time prior to December 31, 2018 (the Term Date). Should the Company fail to satisfy its obligations with regards to the UMD carried costs by the Term Date, the Company will be required to forfeit and assign to UMD its rights and title in any interest earned by the Company pursuant to the Earn-In Agreement. See Note 7 for a discussion of a joint development agreement with UMD.

In August 2017, the Company entered into a purchase and sale agreement with an unaffiliated third party to purchase proved and unproved natural gas and oil properties in the Utica Shale for a purchase price of $62.0 million. A non-refundable deposit of $6.2 million was paid and recorded to other long-term assets on the condensed consolidated balance sheet as of September 30, 2017. This acquisition is expected to close during the fourth quarter of 2017.

4. Long-Term Debt

The Company's long-term debt consisted of the following:

	September 30, 2017	December 31, 2016
	($ in thousands)	
Senior notes due 2022[a]	$ 1,500,000	$ —
Second lien term loans due 2018[b]	—	1,290,263
Convertible notes due 2021[c]	92,093	82,870
Net unamortized debt issuance costs	(3,077)	(40,169)
Net unamortized debt discounts	(28,452)	(7,639)
Total Long-Term Debt, net	$ 1,560,564	$ 1,325,325

(a) The interest rate was 10.0% as of September 30, 2017.
(b) The interest rate was 11.0% at the time of its retirement in April 2017 and as of December 31, 2016.
(c) The interest rate was 5.5% and 4.5% as of September 30, 2017 and December 31, 2016, respectively.

Senior Notes

In April 2017, the Company issued $1.5 billion in aggregate principal amount of senior unsecured notes (2022 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.0% on April 1 and October 1 of each year, commencing on October 1, 2017. Gross proceeds to the Company were $1.466 billion. The proceeds were used to repay and retire all of the Company's outstanding second lien term loans (Second Lien Term Loans) and for general corporate purposes. The Company's obligations under the 2022 Notes are fully and unconditionally guaranteed, jointly and severally by any current and future material subsidiaries of the Company. The Company's 2022 Notes are governed by an indenture containing covenants limiting, among other things, its ability to incur additional indebtedness, make investments or loans, create liens, consummate mergers and similar fundamental changes, make restricted payments, make investments in unrestricted subsidiaries and enter into certain transactions with affiliates. The Company was in compliance with all applicable covenants under the indenture as of September 30, 2017.

At any time prior to April 1, 2020, the Company may redeem up to 35% of the aggregate principal amount of the 2022 Notes at a price equal to 110% of the principal amount, plus accrued and unpaid interest to, but excluding, the redemption date, using the net proceeds of certain equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020, the Company may redeem some or all of the 2022 Notes subject to a make-whole premium plus accrued and unpaid interest to, but excluding, the redemption date. On or after April 1, 2020, the Company may redeem some or all of the 2022 Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below:

Redemption on or after	Redemption Price
April 1, 2020	107.5%
April 1, 2021	105.0%
October 1, 2021 and thereafter	100.0%

The Company and its affiliates are not prohibited from acquiring the 2022 Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise, so long as the acquisition does not violate the terms of the indenture. Upon the occurrence of a qualifying change of control, the Company is required to offer to repurchase all or any part of the 2022 Notes at a purchase price in cash equal to 101% of the aggregate principal amount of the 2022 Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the date of purchase, subject to the rights of the note holders on the relevant record date to receive interest due on an interest payment date that is on or prior to the date the Company repurchased the notes from the holder.

The 2022 Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of its existing and future senior debt, and will rank senior in right of payment to all of its future subordinated debt. The 2022 Notes will be effectively subordinated to all of the Company's existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

In connection with the issuance and sale of the 2022 Notes, the Company entered into a registration rights agreement with the initial purchasers. Pursuant to the registration rights agreement, the Company has agreed to file a registration statement with the Securities and Exchange Commission subsequent to an initial public offering of the Company so that the holders may exchange the 2022 Notes for registered notes that have substantially identical terms. In addition, the Company has agreed to exchange the guarantee related to the 2022 Notes for a registered guarantee having substantially the same terms. The Company will use commercially reasonable efforts to cause the exchange to be completed within 365 days following the closing date of an underwritten public offering by ARUH or any parent entity. If the Company fails to comply with certain obligations to register the 2022 Notes, then for the first 90-day period immediately following such failure the interest rate on the 2022 Notes will increase by 0.25% per annum. The interest rate on the 2022 Notes will increase by an additional 0.25% per annum with respect to each subsequent 90-day period the Company fails to comply with its obligations under the registration rights agreement, up to a maximum aggregate increase of 1.0% per annum. Upon regaining compliance with the terms of the registration rights agreement, the increase in interest rate on the 2022 Notes will cease, and the interest rate will return to the initial annual rate of 10.0%.

Second Lien Term Loans

In September 2013, the Company entered into the Second Lien Term Loans due September 30, 2018. In November 2016, the Company received equity contributions from the Parent of approximately $654.5 million. These equity contributions, combined with previously received equity contributions, surpassed a defined Additional Equity Contribution threshold within the Second Lien Term Loans credit agreement, which resulted in the interest rate decreasing to 9.5% plus the greater of 1.5% or the 3-month London Interbank Offered Rate (LIBOR). Additionally, the Company no longer had the ability to elect to pay up to 2.0% of interest in kind. Previously, the Second Lien Term Loans bore interest at a rate of 11.5% plus the greater of 1.5% or the 3-month LIBOR with the option to elect to pay up to 2.0%, on a per annum basis, of interest in kind, which was compounded and added to the unpaid principal amount of the loan.

In April 2017, the outstanding $1.290 billion in principal of the Second Lien Term Loans was repaid using proceeds from the issuance of the Company's 2022 Notes as discussed herein. The Company paid approximately $1.372 billion in cash, consisting of $1.290 billion applied to the outstanding principal balance, $71.0 million in early redemption fees and $11.0 million in accrued and unpaid interest, resulting in a loss of $108.4 million, including the write-off of unamortized debt issuance costs and discounts, for the nine months ended September 30, 2017.

Convertible Notes

In February 2014, the Company issued $750.0 million of convertible notes due 2021 (Convertible Notes) at a discount to par value of 5.433%. The proceeds were used for the acquisition of natural gas and oil properties and for general corporate purposes. In August 2014, the Company issued an additional $250.0 million of the Convertible Notes at par for the acquisition of natural gas and oil properties. The Company identified certain embedded features in the Convertible Notes that were required to be bifurcated and accounted for as a derivative. The derivative financial instrument was recorded at fair value as of the date of issuance of the Convertible Notes and is re-measured to fair value as of each subsequent balance sheet date and classified as long-term debt in the condensed consolidated balance sheets. See Note 6 for further discussion of the fair value of the embedded derivative.

The Convertible Notes are due on March 1, 2021. Interest may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year and originally was payable at an annual rate of 3.5%. On March 1, 2016, the interest rate began escalating by 0.5% on each subsequent interest payment date, subject to a maximum interest rate of 6.5% per annum, if a preliminary prospectus relating to a qualified initial public offering (Qualified PO) had not been filed under the Securities Act by such date. The Company has elected to pay interest in kind on each interest payment date since September 2015 and the current interest rate, as of September 1, 2017, is 5.5%. Upon maturity, unless earlier paid or converted, the Company will be required to redeem the Convertible Notes at 153.8% of the outstanding principal value, which represents repayment of outstanding principal plus a premium. The Company amortizes the discount on the Convertible Notes to interest expense through the maturity date using the effective interest method.

Conversion of the Convertible Notes into common shares of the qualified public offering issuer (Qualified PO Issuer) following a Qualified PO is at the option of the noteholders. The Qualified PO Issuer may be a business entity that possesses a significant interest in the Company. A Qualified PO is the first public offering of common stock in which the aggregate gross proceeds to the Qualified PO Issuer and the shareholders selling such common stock, if any, equal or exceed $200.0 million and, following such offering, such common stock is listed on a United States securities exchange. Upon conversion, the noteholders will receive common shares of the Qualified PO Issuer equal to the greater of:

1. The aggregate principal amount and accrued interest of the Convertible Notes outstanding on the closing date of the Qualified PO divided by the applicable conversion price. The applicable conversion price is defined as the price per share of common stock in the Qualified PO multiplied by the applicable percentage of the public offering price, which ranges from 80% down to 65% dependent upon the passage of time from the issuance date of the Convertible Notes to the pricing date of the Qualified PO, or

2. The difference between a. and b., as follows:

    a. The common shares of the Qualified PO Issuer immediately prior to considering the effects of conversion divided by one minus a fraction, the numerator is the aggregate principal amount and accrued interest of the Convertible Notes outstanding on the closing date of the Qualified PO and the denominator is the valuation threshold. The valuation threshold refers to an initial equity value of the Company, which is defined as $5.0 billion, subject to adjustments for the Qualified PO. The valuation threshold adjustment will be calculated based upon the equity value of both the Company and the Qualified PO Issuer as of the pricing date of the Qualified PO. The valuation threshold will be adjusted by multiplying the valuation threshold by a fraction. The numerator of said fraction is the equity value of such Qualified PO Issuer, and the denominator is the equity value of the Company.

    b. The common shares of the Qualified PO Issuer immediately prior to considering the effects of conversion.

The Convertible Notes also provide for cash redemption upon a change in control event at the option of the holders at a premium, which as of September 30, 2017 ranged from 142.9% to 153.8% of the principal amount of the Convertible Notes, depending on the change of control date relative to the date issued. The Convertible Notes are not redeemable prior to a change of control or the closing of a Qualified PO. If the closing of a Qualified PO occurs, the Company has the option to redeem all of the Convertible Notes that were not converted at a price equal to 100.0% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any.

In January 2016, the Company announced an offer to exchange (Exchange Offer) the outstanding Convertible Notes for newly issued Convertible Notes due 2021 (New Convertible Notes) and an incremental amount of the Company's previously outstanding junior lien debt, which was retired in November 2016. In exchange for each $1,000 principal amount of the Convertible Notes that was validly tendered and not validly withdrawn, the eligible holder received total exchange consideration consisting of (i) $50 principal amount of the junior lien plus an additional principal amount of junior lien corresponding to 5% of any accrued and unpaid interest on the Convertible Notes and (ii) $950 principal amount of the New Convertible Notes plus an additional principal amount of New Convertible Notes corresponding to 95% of any accrued and unpaid interest on the Convertible Notes. The Exchange Offer closed in February 2016, with $661.9 million in aggregate principal amount of the Convertible Notes, representing 90% of the then outstanding principal amount of the Convertible Notes, validly tendered and not validly withdrawn. As a result of the Exchange Offer, the Company issued $639.3 million in aggregate principal amount of the New Convertible Notes, with a discount of $377.2 million, and recognized a gain on exchange of debt of $306.8 million, including the write-off of unamortized debt issuance costs and discounts associated with the Convertible Notes, for the nine months ended September 30, 2016.

In March 2016, the Company completed a qualified equity sale (Qualified Equity Sale) as defined in the Second Lien Term Loans and on April 1, 2016 provided notice to the holders of the New Convertible Notes that the Company would exercise its option to redeem the New Convertible Notes under the Qualified Equity Sale condition. The redemption price for every $950 principal amount of the New Convertible Notes under the Qualified Equity Sale consisted of $200 principal amount of incremental junior lien together with an additional principal amount for accrued interest and a certain number of the Parent's equity units. In connection with the redemption, the Company issued $138.3 million of incremental junior lien debt, with a discount of $110.7 million, and approximately $237.1 million of equity was issued by the Parent. The redemption resulted in a loss of $4.7 million during the nine months ended September 30, 2016, including the write-off of unamortized debt issuance costs and discounts.

In March 2017, the Company retired $11.1 million of outstanding principal and accrued and unpaid interest associated with the Convertible Notes contributed to the Company by the Member. Additionally, the Company wrote off $0.8 million of associated discounts and embedded derivative liability, which resulted in an increase to equity of $11.9 million.

Credit Facilities

2017 Credit Facility. In April 2017, the Company entered into a $1.5 billion senior secured revolving credit facility (2017 Credit Facility) with a fully committed initial borrowing base of $650.0 million and a sublimit for letters of credit of $450.0 million that matures on December 31, 2021. The 2017 Credit Facility is secured by liens on substantially all of the Company's assets, including its natural gas and oil properties. The amount available to be borrowed under the 2017 Credit Facility is subject to a borrowing base that is redetermined semiannually as of each April 1 and October 1 based on the volumes of the Company's proved natural gas, oil and NGL reserves and estimated cash flows from these reserves and its commodity hedge positions. As of September 30, 2017, the Company had no borrowings under the 2017 Credit Facility with $424.2 million letters of credit outstanding. In October 2017, the borrowing base was increased to a fully committed $925.0 million and the sublimit for letters of credit was increased to $647.5 million. As of November 13, 2017, the Company had no borrowings under the 2017 Credit Facility with $427.7 million letters of credit outstanding.

Principal amounts borrowed are payable on the maturity date and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the prime rate announced by the administrative agent, (ii) the Federal Reserve Bank of New York federal funds rate plus 0.5% and (iii) the rate for 1-month Eurodollar loans, plus an applicable margin ranging from 1.75% and 2.75% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 2.75% to 3.75% per annum. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Under the 2017 Credit Facility agreement, the Company is subject to commitment fees payable to the administrative agent at a rate of 0.5% of the unutilized available borrowing base. Additionally, the Company is subject to letter of credit participation fees payable to the administrative agent which escalate based on pre-determined tiers in accordance with the balance of outstanding letters of credit issued. In connection with the participation fee, the Company is also subject to a fronting fee that is payable to the issuing bank at a rate of 0.125% of the balance of outstanding letters of credit issued. During the three and nine months ended September 30, 2017, the Company incurred $4.9 million and $9.0 million, respectively, in commitment, participation and fronting fees associated with the 2017 Credit Facility, which are presented as interest expense in the condensed consolidated statements of operations.

The 2017 Credit Facility contains restrictive covenants including, but not limited to, restrictions on the Company's ability to incur additional indebtedness, create certain liens on assets, make certain investments or restricted payments, make loans to others, make certain payments, consolidate or merge, hedge hydrocarbons, enter into transactions with affiliates, dispose of assets, or engage in certain other transactions without the prior consent of the lenders. The 2017 Credit Facility also requires the Company to maintain the following two financial ratios: 1) a consolidated leverage ratio, which requires the Company to maintain a consolidated funded indebtedness to consolidated EBITDAX (as defined in the agreement) ratio of not more than 4.25 to 1.00 for the fiscal quarter ending June 30, 2017 and not more than 4.00 to 1.00 for each fiscal quarter thereafter. For purposes of the consolidated leverage ratio, consolidated EBITDAX is calculated over the trailing four fiscal quarter period ending on the date of calculation, provided that for the fiscal quarters ended June 30, 2017, September 30, 2017 and December 31, 2017, consolidated EBITDAX is calculated as the annualized consolidated EBITDAX based on the period from April 1, 2017 through the end of such fiscal quarter, and 2) a modified current ratio per the covenants, which requires the Company to maintain consolidated current assets to consolidated current liabilities of not less than 1.00 to 1.00 as of the end of each fiscal quarter beginning with the quarter ending June 30, 2017. As of September 30, 2017, the Company was in compliance with the financial covenants of the 2017 Credit Facility.

As of September 30, 2017, the Company had incurred $10.2 million in unamortized debt issuance costs associated with the 2017 Credit Facility which are presented as other long-term assets in the condensed consolidated balance sheets.

2016 Credit Facility. In September 2016, the Company entered into a credit facility (2016 Credit Facility) that was collateralized by first lien mortgages on all of the Company's natural gas and oil properties. The 2016 Credit Facility had a borrowing base of $100.0 million and was scheduled to mature on June 30, 2018. In April 2017, the 2016 Credit Facility was replaced by the 2017 Credit Facility. This resulted in the write-off of $5.6 million in unamortized debt issuance costs.

Interest Expense

Interest expense was comprised of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
	($ in thousands)			
Interest expense[(a) (b)]	$ 44,221	$ 73,258	$ 125,504	$ 216,133
Capitalized interest	(25,087)	(58,040)	(96,977)	(172,866)
Long-term debt accretion expense[(c)]	3,703	4,722	9,929	21,766
Deferred debt issuance cost amortization	831	3,588	8,061	11,240
Total interest expense, net	$ 23,668	$ 23,528	$ 46,517	$ 76,273

(a) Includes interest paid in kind of $0.9 million for the three months ended September 30, 2017 compared to $35.9 million for the same period in 2016 and $2.6 million for the nine months ended September 30, 2017 compared to $107.3 million for the same period in 2016.

(b) The three and nine months ended September 30, 2016 includes interest on the junior lien debt of $28.6 million and $80.1 million, respectively, which was retired in November 2016.

(c) Includes accretion of the discount on the Convertible Notes of $2.0 million for the three months ended September 30, 2017 and 2016 and $6.1 million for the nine months ended September 30, 2017 compared to $15.6 million for the same period in 2016.

5. Commodity Derivative Instruments

The Company uses commodity derivative instruments to secure attractive pricing and margins on its share of expected production, to reduce its exposure to fluctuations in future commodity prices and to protect its anticipated operating cash flow against significant market movements or volatility. The Company does not use commodity derivative instruments for speculative or trading purposes. Under the terms of a swap, the Company receives a fixed price for its natural gas or oil production and pays a variable market price to the counterparty. Options are used to establish a floor price (put), a ceiling price (call), or a floor and a ceiling price (collar) for anticipated production. A sold call establishes the maximum price that the Company will receive for contracted commodity volumes. A purchased put establishes the minimum price that the Company will receive for the contracted volumes. Given that the Company's natural gas production is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX, basis swaps may be periodically used to fix or float the differential between product prices at one market location versus another.

All commodity derivative instruments are recognized at their current fair value as either assets or liabilities in the condensed consolidated balance sheets. Changes in the fair value of these commodity derivative instruments are recorded in earnings unless specific hedge accounting criteria are met. The Company elected not to designate any of its commodity derivative instruments for hedge accounting treatment. By using commodity derivative instruments, the Company is exposed to credit risk associated with its hedge counterparties. The Company has entered into commodity derivative instruments with investment-grade rated counterparties.

The following table sets forth the average volumes per day associated with the Company's outstanding natural gas derivative instruments as of September 30, 2017 and the contracted weighted average natural gas prices:

	Average Volume (mmbtu/d)	Weighted Average Prices Swap fixed price	Sold call strike price	Purchased put strike price
			($/mmbtu)	
Natural gas:				
Swaps:				
Remaining in 2017	725,000	$ 3.16		
2018	892,000	$ 3.03		
2019	683,000	$ 2.92		
2020	40,000	$ 2.87		
Basis Swaps:				
Remaining in 2017	84,000	$ (0.11)		
2018	107,500	$ (0.15)		
2019	102,500	$ (0.15)		
Collars:				
2018	134,000		$ 3.27	$ 3.00
Call options:				
Remaining in 2017	50,000		$ 3.25	
2018	50,000		$ 3.25	

The following table sets forth the average volumes per day associated with the Company's outstanding oil derivative instruments as of September 30, 2017 and the contracted weighted average oil prices:

	Average Volume (bbl/d)	Weighted Average NYMEX ($/bbl)
Oil :		
Swaps:		
Remaining in 2017	5,300	$ 54.19
2018	3,500	$ 53.42
2019	1,000	$ 50.94

The following tables summarize the classification and fair value amounts of all commodity derivative instruments in the condensed consolidated balance sheets as of September 30, 2017 and December 31, 2016, as well as the gross recognized derivative assets and liabilities and amounts offset in the condensed consolidated balance sheets:

	Condensed Consolidated Balance Sheet Classification	September 30, 2017 Gross Recognized Fair Value	Amounts Netted in Balance Sheet	Net Recognized Fair Value in Balance Sheet
			($ in thousands)	
Derivative assets:				
Natural gas and oil commodity derivatives	Short-term derivative assets	$ 35,114	$ (21,348)	$ 13,766
Natural gas and oil commodity derivatives	Long-term derivative assets	$ 27,660	$ (26,584)	$ 1,076
Derivative liabilities:				
Natural gas and oil commodity derivatives	Short-term derivative liabilities	$ (26,086)	$ 21,348	$ (4,738)
Natural gas and oil commodity derivatives	Long-term derivative liabilities	$ (33,938)	$ 26,584	$ (7,354)

	Condensed Consolidated Balance Sheet Classification	December 31, 2016 Gross Recognized Fair Value	Amounts Netted in Balance Sheet	Net Recognized Fair Value in Balance Sheet
		($ in thousands)		
Derivative assets:				
Natural gas and oil commodity derivatives	Short-term derivative assets	$ 342	$ (342)	$ —
Natural gas and oil commodity derivatives	Long-term derivative assets	$ 652	$ (652)	$ —
Derivative liabilities:				
Natural gas and oil commodity derivatives	Short-term derivative liabilities	$ (74,831)	$ 342	$ (74,489)
Natural gas and oil commodity derivatives	Long-term derivative liabilities	$ (20,066)	$ 652	$ (19,414)

The following table summarizes the effects of commodity derivative instruments in the condensed consolidated statements of operations for the three and nine months ended September 30, 2017 and 2016:

	Condensed Consolidated Statements of Operations Earnings Caption	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
		($ in thousands)			
Natural gas and oil commodity derivatives	Commodity derivative (loss) gain	$ (17,248)	$ 9,338	$ 105,185	$ (8,753)

6. Fair Value Measurements

The Company uses a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. The three levels are defined as follows:

Level 1 – Unadjusted quoted prices for identical assets or liabilities in active markets.

Level 2 – Quoted prices for similar assets or liabilities in active markets; quoted prices for identical or similar assets or liabilities in markets that are not active; and model-derived valuations whose inputs or significant value drivers are observable.

Level 3 – Unobservable inputs that reflect the Company’s own assumptions.

Fair Value of Derivative Instruments

The following tables summarize the valuation of financial instruments by pricing levels that were accounted for at fair value on a recurring basis as of September 30, 2017 and December 31, 2016. The fair values of the natural gas and oil commodity derivatives are based primarily on inputs that are derived from observable data at commonly quoted intervals and are therefore classified as Level 2. See Note 5 for further information on commodity derivative instruments.

Description	Fair value measurements at September 30, 2017 using: Level 1	Level 2	Level 3	Total
	($ in thousands)			
Derivative assets:				
Natural gas and oil commodity derivatives	$ —	$ 14,842	$ —	$ 14,842
Total	$ —	$ 14,842	$ —	$ 14,842
Derivative liabilities:				
Natural gas and oil commodity derivatives	$ —	$ 12,092	$ —	$ 12,092
Embedded derivative [1]	—	—	23,233	23,233
Total	$ —	$ 12,092	$ 23,233	$ 35,325

[1] This is included in long-term debt on the condensed consolidated balance sheet as of September 30, 2017.

Description	Fair value measurements at December 31, 2016 using: Level 1	Level 2	Level 3	Total
	($ in thousands)			
Derivative liabilities:				
Natural gas and oil commodity derivatives	$ —	$ 93,903	$ —	$ 93,903
Embedded derivative [1]	—	—	5,403	5,403
Total	$ —	$ 93,903	$ 5,403	$ 99,306

(1) This is included in long-term debt on the condensed consolidated balance sheet as of December 31, 2016.

The Company determined that certain embedded features in the Convertible Notes were required to be bifurcated and accounted for as a derivative. The Company determined the fair value of the embedded derivative using a "with" and "without" analysis. This requires (a) estimating the fair value of the Convertible Notes with all the features (including the change of control or Qualified PO premium and the conversion option) within an option pricing framework and (b) subtracting the fair value of the host excluding the embedded derivative. The Company has classified the fair value of the embedded derivative related to the Convertible Notes as Level 3 due to the fact that the valuation is based upon significant unobservable inputs.

The key inputs used to calculate the fair value of the embedded derivative are as follows:

	September 30, 2017	December 31, 2016
Trading price of Convertible Notes	98.0%	15.0%
Probability of Qualified PO or change in control	5% - 75% with a total of 100% over the expected term	5% - 50% with a total of 100% over the expected term
Expected term	Between 0 and 4 years	Between 1 and 3 years
Discount rate with and without embedded features pre-exit	8.0%	46.0%
Discount rate without embedded features post-exit	2.5%	41.0%

The following table presents a summary of changes in the fair value of the embedded derivative liability classified as a Level 3 measurement:

	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	($ in thousands)			
Balance, beginning of period	$ (22,600)	$ (778)	$ (5,403)	$ (16,025)
Change due to purchases or exchanges of debt	—	—	773	7,006
Change in fair value [a]	(633)	—	(18,603)	8,241
Balance, end of period	$ (23,233)	$ (778)	$ (23,233)	$ (778)

(a) Included in change in fair value of embedded derivative on the condensed consolidated statements of operations.

Fair Value of Debt

The carrying amount and estimated fair value of long-term debt as of September 30, 2017 and December 31, 2016 is shown in the table below. The fair value was estimated using Level 2 market data inputs. See Note 4 for further information regarding long-term debt.

	September 30, 2017		December 31, 2016	
	Carrying Value	Fair Value	Carrying Value	Fair Value
	($ in thousands)			
2022 Notes	$ 1,466,936	$ 1,610,625	$ —	$ —
Second Lien Term Loans	—	—	1,247,082	1,293,490
Convertible Notes	93,628	90,251	78,243	66,296
Total	$ 1,560,564	$ 1,700,876	$ 1,325,325	$ 1,359,786

7. Related Party Transactions

Management Services Agreement

The Company entered into a management services agreement with the Member (ARO MSA) effective August 1, 2015. Under the ARO MSA, the Member performs any and all general management, administrative and operating services requested by and at the direction of the Company. The Member invoices the Company monthly for cash it paid for any costs expended on behalf of the Company in performance of the services. The initial term of the agreement was twelve months, and on August 1, 2016 it was automatically extended for an additional twelve months. On August 1, 2017, the agreement was automatically extended on a month-to-month basis and can be terminated by either party upon not less than 30 days notice. The ARO MSA will be automatically terminated at the earlier of the Company ceasing to hold assets or an initial public offering of the Parent. During the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016, the Company incurred approximately $14.4 million, $12.8 million, $42.6 million and $34.0 million respectively, for the services performed under the ARO MSA, of which $6.2 million, $3.8 million, $15.9 million and $10.9 million, respectively, related to direct labor or overhead and was recognized in lease operating expenses or natural gas and oil properties, as applicable.

UMD Agreements

The Company and UMD are each indirectly, majority owned by investment funds controlled by EMG and First Reserve Corporation. In May 2017, the Company and UMD entered into a development agreement (Development Agreement) whereby an area of mutual interest (AMI) was established encompassing Jefferson county in Ohio. Within the AMI, each party will have the option to participate in the acquisition of natural gas and oil interests made by the other party according to an agreed upon pro-rata share of up to 50% for UMD and up to 50% for the Company. Properties acquired by UMD, and not subject to a pre-existing unit operating agreement, will be operated by the Company. Unless terminated at an earlier date by the mutual agreement of the parties, the AMI will remain in effect for the shorter of three years or the date that UMD has, in the aggregate, elected to participate with its pro-rata share of 5,000 net acres within the AMI. As of September 30, 2017, UMD had paid the Company $1.4 million for 276 acres pursuant to the Development Agreement.

In August 2017, the Company and UMD completed an acquisition of the Acquisition Properties and entered into the Earn-In Agreement that is discussed in Note 3.

Incentive Units

In order to provide incentives to certain officers, employees, consultants and professionals of the Parent and certain of its affiliates, the Parent and certain of its affiliates established incentive compensation plans. Holders of incentive units are entitled to certain future distributions which are triggered after the recovery of specified members' capital contributions plus a rate of return. For the three and nine months ended September 30, 2017 and 2016, the Company had nominal expenses or (income) associated with incentive units, which is included on the condensed consolidated statements of operations in general and administrative expenses - related party.

Transactions Related to Ascent Resources - Marcellus, LLC

The Company may have excess capacity available on certain firm transportation delivery routes. To minimize excess capacity charges, the Company regularly enters into asset management agreements (AMA) with third parties. Under the AMAs, the Company may direct the third party to purchase natural gas production from Ascent Resources - Marcellus, LLC (ARM), an affiliated entity, to utilize the Company's excess capacity, in the same manner the AMA third party would negotiate and purchase gas from a third party producer. The Company receives a percentage of the margin on the AMA third parties' ultimate sales price to its customers over the price the third parties paid to ARM to purchase the natural gas production. This margin is classified as a reduction to gathering, processing and transportation expenses. For the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016, the Company recognized $0, $13.5 million, $3.2 million and $24.3 million, respectively, related to ARM's production as a reduction to gathering, processing and transportation expenses.

Related Party Gas Gathering, Firm Transportation and Processing Agreements

In August 2015, the Company entered into a gas gathering agreement with Jefferson Gas Gathering Company, LLC (Jefferson). EMG has significant influence over Jefferson through its equity investment in Jefferson's parent, MarkWest EMG Jefferson Dry Gas Gathering Company, LLC. The costs incurred under the gas gathering agreement with Jefferson for the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016 were approximately $12.0 million, $1.7 million, $22.2 million and $3.4 million, respectively. At September 30, 2017 and December 31, 2016, the Company had a payable to Jefferson of $9.0 million and $1.8 million, respectively.

In September 2014, the Company entered into a gas gathering agreement with Ohio Gathering Company, LLC (Ohio Gathering). Ohio Gathering is a joint venture of MarkWest Utica EMG, LLC (MWU EMG). EMG has significant influence over Ohio Gathering through its equity investment in MWU EMG. The Company also entered into a gas processing and fractionation agreement with MWU EMG. The costs incurred for the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016 under the gas gathering agreement with Ohio Gathering were $9.6 million, $5.8 million, $27.1 million and $16.8 million, respectively. The costs incurred under the gas processing and fractionation agreement with MWU EMG for the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016 were $8.7 million, $5.7 million, $27.5 million and $19.4 million, respectively. At September 30, 2017 and December 31, 2016, the Company had a payable to Ohio Gathering of $3.1 million and $8.0 million, respectively.

In April 2014, the Company entered into a firm transportation agreement with Rockies Express Pipeline LLC (REX). REX is a joint venture of Tallgrass Development, LP and Tallgrass Energy Partners, LP (together, Tallgrass). EMG has significant influence over REX through its equity investments in Tallgrass. Transportation commitments commenced on August 1, 2015, and continue through 2035. Furthermore, in October 2014, the Company entered into an additional firm transportation agreement with REX. Transportation commitments commenced in December 2016 and will continue through 2031. The costs incurred under the firm transportation agreements with REX for the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016 were $28.1 million, $20.5 million, $84.0 million and $61.6 million, respectively. At September 30, 2017 and December 31, 2016, the Company had a payable to REX of $9.4 million and $7.6 million, respectively. For information regarding the credit support requirements due to REX, see Note 8.

In August 2014, the Company entered into a gathering and compression agreement with Ohio River System LLC (ORS). Traverse Midstream Partners LLC (Traverse), an EMG controlled entity, through its subsidiaries owns a 25% interest in ORS. ORS operates a 52-mile natural gas gathering system which was placed in service in the fourth quarter of 2015. The primary term of the agreement is 15 years with an option for the Company to extend the term for one renewal term of five years. The costs incurred during the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016 under the gathering and compression agreement with ORS were approximately $6.5 million, $1.9 million, $14.0 million and $4.3 million, respectively. At September 30, 2017 and December 31, 2016, the Company had a payable to ORS of $2.6 million and $1.5 million, respectively. For information regarding the credit support requirements due to ORS, see Note 8.

In June 2014, the Company entered into a firm transportation agreement with Rover Pipeline LLC (Rover). Traverse, through its subsidiaries, owns a 35% interest in Rover. In October 2017, partial transportation services per the Company's agreement with Rover began and full transportation services provided under the agreement are expected to commence by March 31, 2018. The firm transportation agreement has a primary term of 15 years with an option for the Company to extend the term up to four consecutive times for a term of five years per extension. There were no costs incurred under the firm transportation agreement with Rover during the three and nine months ended September 30, 2017. At September 30, 2017, the Company had no payables to Rover. For information regarding the credit support requirements due to Rover, see Note 8.

Convertible Notes

In March 2017, the Company retired $11.1 million of outstanding principal and accrued and unpaid interest associated with Convertible Notes contributed to the Company by the Member. Additionally, the Company wrote off $0.8 million of associated discounts and embedded derivative liability, which resulted in an increase to equity of $11.9 million.

8. Commitments and Contingencies

Litigation Matters

The Company is periodically involved in litigation and regulatory proceedings, investigations and disputes, including matters relating to commercial transactions, operations, landowner disputes, royalty claims and environmental, health and safety matters. A liability is recognized for any contingency that is probable of occurrence and reasonably estimable. The Company continually assesses the likelihood of adverse judgments or outcomes in these matters, as well as potential ranges of possible losses, based on a careful analysis of each matter with the assistance of legal counsel and, if applicable, other experts. The Company will continue to monitor the impact that litigation could have on the Company and will assess the impact of future events. Legal defense costs are accounted for in the period the costs are incurred.

Based on management's current assessment, the Company is of the opinion that no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its future consolidated financial position, results of operations or cash flows. The final resolution of such matters could exceed amounts accrued, however, and actual results could differ materially from management's estimates

Environmental Matters

The Company is subject to existing federal, state and local laws and regulations governing environmental matters, such as the Comprehensive Environmental Response, Compensation and Liability Act and similar statutes. From time to time, the Company is party to various environmental and regulatory proceedings in the ordinary course of business. Management does not believe the results of these environmental proceedings, individually or in the aggregate, will have a material adverse effect on the Company.

Commitments

The following table presents the Company's undiscounted commitments under unconditional purchase obligations, excluding any reimbursement from working interest and royalty interest owners, where appropriate, or credits for third party volumes, as of September 30, 2017:

Period	Pipeline Transportation	Drilling Rigs	Other Commitments	Total
		($ in thousands)		
Remaining in 2017	$ 102,855	$ 4,258	$ 210	$ 107,323
2018	555,770	12,988	695	569,453
2019	604,106	5,224	573	609,903
2020	627,561	—	224	627,785
2021	646,587	—	—	646,587
Thereafter	8,025,607	—	—	8,025,607
Total	$ 10,562,486	$ 22,470	$ 1,702	$ 10,586,658

Pipeline Transportation Commitments

As of September 30, 2017, the Company had certain pipeline transportation commitments which will reduce the impact of possible production curtailments that may arise due to limited transportation capacity. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. To enter into certain of these commitments, the Company made certain deposits, which have been primarily reimbursed and replaced by letters of credit. As of September 30, 2017, the remaining deposits are shown as deposits on pipeline transportation on the condensed consolidated balance sheets. Subsequent to September 30, 2017, the deposits outstanding on pipeline transportation were fully reimbursed and replaced by letters of credit, and there are no deposits outstanding.

As discussed in Note 7, the Company entered into certain firm transportation agreements with ORS and Rover. The Company is obligated to provide ORS with credit support ranging from $40.0 million to $70.0 million. The Company is obligated to provide Rover with credit support in the amount of one year of demand charges, which may reach $250.1 million.

Pursuant to an agreement (the Pledge Agreement) between the Company and Traverse, Traverse was required to satisfy the Company's credit obligation to ORS (the ORS Pledge) and to Rover (the Rover Pledge). Commencing February 1, 2016 for the ORS Pledge and July 1, 2016 for the Rover Pledge and until such time as the Pledge Agreement was terminated, the Company paid Traverse an amount equal to 2.75% per annum, increasing on each August 1 and July 1, respectively, thereafter by 0.25% per annum (capped at 4.0%), payable quarterly in arrears, on the value of the collateral posted by Traverse under the Pledge Agreement. In April 2017, the Pledge Agreement, and corresponding ORS and Rover Pledges, were terminated after the Company purchased and retired the Second Lien Term Loans and provided collateral directly to ORS and Rover in the form of letters of credit under the 2017 Credit Facility. During the three months ended September 30, 2017 and 2016 and the nine months ended September 30, 2017 and 2016, the Company incurred $0, $1.7 million, $2.1 million and $2.1 million, respectively, in interest expense associated with the credit support obligations for the ORS and Rover Pledges. As of September 30, 2017, the Company had issued a $40.0 million letter of credit to ORS and $241.3 million in letters of credit to Rover.

As discussed in Note 7, the Company entered into certain firm transportation agreements with REX. The Company is obligated to provide REX with credit support for its shipping commitments. During 2017, the Company was refunded $50.8 million in cash deposits previously made upon the issuance of letters of credit under the 2017 Credit Facility for the same amount to satisfy the obligation. As of September 30, 2017, the Company has issued $67.8 million in the form of letters of credit and has $61.6 million in surety bonds outstanding as collateral to satisfy its shipping commitments with REX.

Drilling Rig Commitments

The Company has entered into various drilling rig contracts to utilize drilling services at market-based pricing. The Company's drilling rig commitments were entered into in the ordinary course of business to ensure rig availability allowing the Company to execute its business objectives. These commitments are reflected in the table above.

Fixed Price Contract Commitments

The Company occasionally enters into agreements in the ordinary course of business to sell certain physical volumes of its natural gas and oil production at fixed prices. These contracts can be for one month or longer and provide pricing certainty with respect to a portion of the Company's natural gas and oil production volumes.

The Company has entered into the following contracts as of September 30, 2017:

	Natural Gas	
Period	Volumes (mmbtu/d)	Fixed Price $/mmbtu
Q4 2017	50,000	$ 3.01

Joint Venture Commitments

In 2013, the Company entered into a joint venture participation agreement with RHDK Oil and Gas, LLC in order to acquire interests in unproved leasehold. Under the agreement, the Company is required to pay the seller's retained share of development costs ("carried costs") for certain wells and other development operations that occur within an area of mutual interest as defined in the agreement. The acquisition obligation represents the difference in the purchase price of the interests in unproved leasehold and the cash paid by the Company. The agreement further stipulates that if the Company fails to repay its obligation for such carried costs by certain periods of time, then the Company will be required to pay the seller any shortfall in cash. On February 19, 2016, the Company executed an amendment to extend the payment terms of carried costs from four years to five years. As of September 30, 2017 and December 31, 2016, the Company owed $86.2 million and $103.3 million, respectively, for this obligation. This obligation was discounted using an 11% discount rate, to reflect the imputation of interest, and is classified as a current liability on the condensed consolidated balance sheet as of September 30, 2017.

In 2014, the Company entered into a joint venture participation agreement with XTO Energy, Inc. (XTO) and Phillips Exploration, Inc. (Phillips). The participation agreement governs the funding, exploration, and development of the parties' jointly owned interests through the earliest to occur of either (a) January 29, 2024, (b) the point in time when all the lands covered by the leases have been made the subject of assignments, delivered to the respective receiving party or (c) the date at which the cumulative carry bank (Carry Bank), as defined in the agreement, equals zero dollars. The initial agreement provided that the Company would acquire a 40% interest in non-operated wells upon certain defined acreage and a 95% interest in operated wells upon certain defined acreage. In exchange, the Company would carry 100% of XTO and Phillips' share of development costs until the Carry Bank is depleted. The Carry Bank was defined in the initial agreement as the positive amount, if any, by which (a) the sum of 40% of the aggregate allocated value of the XTO core leases (as defined in the agreement), and 95% of the aggregate allocated value of the XTO non-core leases (as defined in the agreement) exceeds (b) the sum of 60% of the aggregate allocated value of the Company's core leases and the amount of all carried costs previously paid by the Company.

In March 2016, the Company and XTO amended the joint venture participation agreement such that the interest the Company would acquire would be reduced to a 5% interest in non-operated wells across a smaller amount of defined acreage and a 95% interest in operated wells across a larger amount of defined acreage. This included an adjustment to already earned acreage, which resulted in a reduction to the Carry Bank of approximately $80.0 million. The amendment revised certain contractual leasehold interests as defined in the agreement to provide XTO with a greater percentage interest in leases in a smaller XTO operated core area, with the Company obtaining an additional area to operate at a 95% working interest. As of September 30, 2017 and December 31, 2016, the Carry Bank was $7.3 million and $79.7 million, respectively. Participation in the joint venture is required by all parties while the Carry Bank has a positive balance.

9. Other Current Liabilities

The Company's other current liabilities consisted of the following as of September 30, 2017 and December 31, 2016:

	September 30, 2017	December 31, 2016
	($ in thousands)	
Drilling and completion accrual	$ 116,109	$ 60,448
Gathering, processing and transportation expense accrual	41,231	28,915
Other	48,767	25,072
Total other current liabilities	$ 206,107	$ 114,435

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

Our Management's Discussion and Analysis of our Financial Condition and Results of Operations ("MD&A") should be read in conjunction with our condensed consolidated financial statements and related notes, included herein. The following discussion and analysis contains forward-looking statements that involve known and unknown risks, uncertainties and assumptions. The forward-looking statements are not historical facts, but rather reflect our future plans, estimates, beliefs and expected performance. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

Unless otherwise indicated or the context otherwise requires, references in this MD&A section to "we", "our", and "us" refer to Ascent Resources Utica Holdings, LLC together with its wholly-owned subsidiaries.

Overview

We are an independent exploration and production company engaged in the acquisition, exploration and development of natural gas, oil and natural gas liquids (NGL) properties in the Utica Shale of the Appalachian Basin. We are a wholly-owned subsidiary of Ascent Resources Operating, LLC (the Member), an indirect wholly-owned subsidiary of Ascent Resources, LLC (the Parent). We were formed in 2013, by our private equity sponsors, primarily The Energy & Minerals Group (EMG) and First Reserve Corporation, to utilize our technical expertise to acquire and exploit assets in the Utica Shale. Our asset base is concentrated in southern Ohio, where we target primarily the Point Pleasant interval of the Utica, one of the premier North American shale plays. Our largely contiguous acreage lies within the core of the southern Utica and, as supported by our drilling results and those of offset operators, offers development opportunities with predictable and repeatable production profiles, low breakeven costs and industry-leading rates of return. We have strategically assembled our position in the southern Utica because of advantageous geological and petrophysical characteristics, including significant overpressure, strong formation seals, favorable rock mechanics (fracturability) and low water saturations in this region, resulting in substantial hydrocarbons in place and well results that are among the most productive in the Utica.

We are continuously focused on enhancing our drilling and completion techniques, minimizing costs and maximizing the ultimate recovery of hydrocarbons from our assets, with the goal of generating top-tier corporate-level returns. The success of our differentiated operational approach is evident in the results of our operated wells. For example, in October 2017, we achieved one bcfe per day of net production from only 185 gross (156 net) operated wells.

As of September 30, 2017, we had approximately 180 gross (152 net) operated wells producing and an interest in 186 gross (13 net) non-operated producing wells compared to 100 gross (82 net) operated wells producing and an interest in 156 gross (12 net) non-operated producing wells at September 30, 2016.

2017 Highlights

- In October, we executed the first amendment for the $1.5 billion revolving credit facility (2017 Credit Facility), which was entered into in April and replaced the existing credit facility (2016 Credit Facility). The borrowing base was increased from $650.0 million to $925.0 million and the sublimit for letters of credit was increased from $450.0 million to $647.5 million.
- In August, we, together with Utica Minerals Development, LLC (UMD), acquired approximately 10,400 net acres in the Utica Shale in Ohio from an unaffiliated seller (the Acquisition Properties) for a purchase price of $98.2 million, subject to customary post-closing adjustments. At closing, we received an undivided 25% interest in the Acquisition Properties for $33.4 million with UMD receiving the remaining undivided 75% interest in the Acquisition Properties. The Acquisition Properties consisted of unproved leasehold.
- Pursuant to an agreement between us and UMD (the Earn-In Agreement), we may earn an additional undivided 25% interest in the Acquisition Properties from UMD by drilling and operating a designated set of wells on the Acquisition Properties and carrying 100% of UMD's drilling and completion costs (carried costs) of approximately $22.0 million. Upon our full payment of the UMD carried costs, each party will own an undivided 50% interest in the Acquisition Properties. In accordance with the Earn-In Agreement, we will have the right to pay the outstanding balance of the carry, and any prepayment penalty (if applicable), at any time prior to December 31, 2018 (the Term Date). Should we fail to satisfy our obligations with regards to the UMD carried costs by the Term Date, we will be required to forfeit and assign to UMD our rights and title in any interest earned by us pursuant to the Earn-In Agreement. See Note 7 of the notes to our condensed consolidated financial statements for a discussion of a joint development agreement with UMD.
- In August, we entered into a purchase and sale agreement with an unaffiliated third party to purchase proved and unproved natural gas and oil properties in the Utica Shale for a purchase price of $62.0 million. A non-refundable deposit of $6.2 million was paid and recorded to other long-term assets on the condensed consolidated balance sheet as of September 30, 2017. This acquisition is expected to close during the fourth quarter of 2017.

- In April, we closed on the issuance of $1.5 billion in aggregate principal amount of 10.0% senior unsecured notes (2022 Notes). The net proceeds were used to repay and retire all of our outstanding second lien term loans (Second Lien Term Loans) and for general corporate purposes.
- In March, we retired $11.1 million of outstanding principal and accrued and unpaid interest associated with certain Convertible Notes (defined below) contributed to us by the Member.

Financial Data

The following table sets forth certain information regarding our production volumes, natural gas, oil and NGL sales, average sales prices received, and certain of our operating expenses for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Net Production Volumes:				
Natural gas (mmcf)	66,495	29,725	155,987	75,246
Oil (mbbls)	604	432	2,006	1,650
NGL (mbbls)	779	655	2,519	2,065
Natural Gas Equivalent (mmcfe)	74,793	36,246	183,137	97,534
Natural Gas, Oil, and NGL Sales ($ in thousands):				
Natural gas	$ 177,646	$ 73,179	$ 457,797	$ 167,590
Oil	25,609	16,876	87,409	50,880
NGL	17,047	7,556	53,474	25,719
Commodity derivative (loss) gain	(17,248)	9,338	105,185	(8,753)
Total	$ 203,054	$ 106,949	$ 703,865	$ 235,436
Average Daily Production Volumes:				
Natural gas (mmcf/d)	723	323	571	275
Oil (mbbls/d)	7	5	7	6
NGL (mbbls/d)	9	7	9	8
Natural Gas Equivalent (mmcfe/d)	813	394	671	356
Average Sales Prices, Before Derivatives:				
Natural gas ($/mcf)	$ 2.67	$ 2.46	$ 2.93	$ 2.23
Oil ($/bbl)	$ 42.40	$ 39.05	$ 43.58	$ 30.84
NGL ($/bbl)	$ 21.89	$ 11.54	$ 21.22	$ 12.46
Natural Gas Equivalent ($/mcfe)	$ 2.95	$ 2.69	$ 3.27	$ 2.50
Settlements of commodity derivatives ($/mcfe)	0.13	(0.17)	0.05	0.08
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.08	$ 2.52	$ 3.32	$ 2.58
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.14	$ 0.08	$ 0.13	$ 0.20
Gathering, processing and transportation expenses	$ 1.04	$ 1.23	$ 1.24	$ 1.44
Production and ad valorem taxes	$ 0.05	$ 0.05	$ 0.05	$ 0.06
General and administrative expenses	$ 0.02	$ 0.04	$ 0.02	$ 0.06
General and administrative expenses – related party	$ 0.11	$ 0.25	$ 0.15	$ 0.24
Natural gas and oil depreciation, depletion and amortization	$ 1.07	$ 1.71	$ 1.14	$ 1.75
Depreciation and amortization of other assets	$ 0.01	$ 0.01	$ 0.01	$ 0.01

Liquidity and Capital Resources

Liquidity Overview

Our natural gas, oil and NGL operations, including our exploration, drilling and production operations, are capital intensive activities that require access to significant capital. We continually evaluate our capital needs and compare them to our capital resources. Historically, our primary sources of funds have been through equity contributions from our Parent, asset sales and proceeds from the issuance of debt. Equity contributions from our Parent, cash on hand, cash flow from operations, future draws on our credit facility and other capital market transactions will be the primary sources of liquidity in the future.

As of September 30, 2017, we had a cash balance of $248.6 million. In April 2017, we issued $1.5 billion in aggregate principal amount of 2022 Notes in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. Gross proceeds were $1.466 billion. The proceeds were used to repay and retire all of our outstanding Second Lien Term Loans and for general corporate purposes. Contemporaneously, we entered into the 2017 Credit Facility to replace the 2016 Credit Facility with a fully committed initial borrowing base of $650.0 million and a maturity date of December 31, 2021. In October 2017, the borrowing base was redetermined and adjusted to a fully committed amount of $925.0 million. As of November 13, 2017, we had no borrowings under the 2017 Credit Facility with $427.7 million letters of credit outstanding. Based on our current cash balance, credit facility availability and expected operating cash flows, we anticipate to be able to satisfy all of our financial obligations and commitments for the next twelve months.

We anticipate a significant increase in our revenues for the remainder of 2017 and throughout 2018 due to expected increased production and higher realized prices compared to 2016. Substantial capital expenditures are required to replace reserves as well as sustain and increase production. A substantial or extended decline in natural gas, oil and NGL prices could have a material impact on our financial position, results of operations, cash flows and quantities of natural gas, oil and NGL reserves that may be economically produced. Furthermore, in a low commodity price environment our ability to generate positive operating cash flows, maintain our natural gas, oil and NGL production and reserves, raise additional capital, sell assets, or take any other action to improve our liquidity is subject to risks and uncertainties that exist in our industry, some of which we may not be able to anticipate at this time or control.

Sources of Funds

The following table presents the sources of cash and cash equivalents:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	($ in thousands)	
Cash provided by operating activities	$ 228,878	$ 26,371
Proceeds from divestitures of unproved natural gas and oil properties	—	16,664
Proceeds from sale of other property and equipment	13	—
Reduction in deposits on pipeline transportation	147,715	—
Proceeds from issuance of long-term debt, net	1,466,250	—
Contributions from Member	132,000	677,229
Total Sources of Cash and Cash Equivalents	$ 1,974,856	$ 720,264

Net cash flow provided by operating activities was approximately $228.9 million for the nine months ended September 30, 2017, compared to $26.4 million provided by operating activities for the nine months ended September 30, 2016. The increase in operating cash flow from the nine months ended September 30, 2016 to the nine months ended September 30, 2017 was primarily the result of higher realized prices and increased natural gas, oil and NGL production.

Uses of Funds

The following table presents the uses of cash and cash equivalents:

	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
	($ in thousands)	
Oil and Natural Gas Expenditures:		
Drilling and completion costs	$ (434,087)	$ (201,003)
Acquisitions of proved and unproved natural gas and oil properties [(a)]	(249,646)	(315,530)
Deposit on natural gas and oil property acquisition	(6,200)	—
Additions to deposits on pipeline transportation	—	(35,394)
Other Uses of Cash and Cash Equivalents:		
Repayment of debt	(1,290,264)	—
Additions to other property and equipment	(140)	(715)
Cash paid for debt issuance costs	(14,366)	(7,846)
Repayment of note payable to third party	—	(37,170)
Total Uses of Cash and Cash Equivalents	$ (1,994,703)	$ (597,658)

[(a)] Includes capitalized interest of $47.6 million and $107.0 million for the nine months ended September 30, 2017 and 2016, respectively.

Certain Indebtedness

Credit Facilities

2017 Credit Facility. The 2017 Credit Facility is subject to a borrowing base that is redetermined semiannually as of each April 1 and October 1 based on the volumes of our proved natural gas, oil and NGL reserves and estimated cash flows from these reserves and our commodity hedge positions. As of September 30, 2017, we had no borrowings under the 2017 Credit Facility with $424.2 million letters of credit outstanding. In October 2017, the borrowing base was increased to $925.0 million and the sublimit for letters of credit was increased to $647.5 million. As of November 13, 2017, we had no borrowings under the 2017 Credit Facility with $427.7 million letters of credit outstanding.

Principal amounts borrowed are payable on the maturity date and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the prime rate announced by the administrative agent, (ii) the Federal Reserve Bank of New York federal funds rate plus 0.5% and (iii) the rate for one month Eurodollar loans, plus an applicable margin ranging from 1.75% to 2.75% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 2.75% to 3.75% per annum. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. The 2017 Credit Facility is secured by liens on substantially all of our properties, including our natural gas and oil properties, and guarantees from our subsidiaries other than any subsidiary that we have designated as an unrestricted subsidiary. As of September 30, 2017, we were in compliance with all applicable financial covenants under the credit agreement. See Note 4 of the notes to our condensed consolidated financial statements for further discussion of the terms of the 2017 Credit Facility.

2016 Credit Facility. The 2016 Credit Facility had a borrowing base of $100.0 million and was scheduled to mature on June 30, 2018. In April 2017, the 2016 Credit Facility was replaced by the 2017 Credit Facility. This resulted in the write-off of $5.6 million in unamortized debt issuance costs.

Senior Notes

The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.0% on April 1 and October 1 of each year, commencing on October 1, 2017. At any time prior to April 1, 2020, we may redeem up to 35% of the aggregate principal amount of the 2022 Notes at a price equal to 110% of the principal amount, plus accrued and unpaid interest to, but excluding, the redemption date, using the net proceeds of certain equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020, we may redeem some or all of the 2022 Notes subject to a make-whole premium plus accrued and unpaid interest to, but excluding, the redemption date. On or after April 1, 2020, we may redeem some or all of the 2022 Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below:

Redemption on or after	Redemption Price
April 1, 2020	107.5%
April 1, 2021	105.0%
October 1, 2021 and thereafter	100.0%

We and our affiliates are not prohibited from acquiring the 2022 Notes by means other than a redemption, whether pursuant to a tender offer, open market purchase or otherwise, so long as the acquisition does not violate the terms of the indenture. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2022 Notes at a purchase price in cash equal to 101% of the aggregate principal amount of the 2022 Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the date of purchase, subject to the rights of the note holders on the relevant record date to receive interest due on an interest payment date that is on or prior to the date we repurchased the notes from the holder.

The 2022 Notes are our senior unsecured obligations and rank equally in right of payment with all of our existing and future senior debt, and will rank senior in right of payment to all our future subordinated debt. The 2022 Notes will be effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

As of September 30, 2017, we were in compliance with all applicable covenants of the 2022 Notes indenture. See Note 4 of the notes to our condensed consolidated financial statements for further discussion of the terms of the 2022 Notes.

Convertible Notes

In February 2014, we issued $750.0 million of convertible notes due 2021 (Convertible Notes). In August 2014, we issued an additional $250.0 million of Convertible Notes. As a result of the offer to exchange (Exchange Offer) the outstanding Convertible Notes for newly issued Convertible Notes due 2021 (New Convertible Notes) in February 2016, and the redemption of the New Convertible Notes in April 2016, an aggregate principal amount of $68.5 million remained outstanding as of September 30, 2017.

Interest on the Convertible Notes may be paid in cash or in kind semi-annually in arrears on March 1 and September 1 of each year and originally was payable at an annual rate of 3.5%. On March 1, 2016, the interest rate began escalating by 0.5% on each interest payment date, subject to a maximum interest rate of 6.5% per annum, if a preliminary prospectus relating to a qualified initial public offering (Qualified PO) had not been filed under the Securities Act by such date. We have elected to pay interest in kind on each interest payment date since September 2015 and the current interest rate, as of September 1, 2017, is 5.5%. The Convertible Notes are subordinated in right of payment to all of our existing and future senior unsecured indebtedness, rank pari passu in right of payment with all of our existing and future subordinated indebtedness, and rank senior in right of payment to all of our existing and future junior subordinated indebtedness. The indenture governing the Convertible Notes does not restrict us or our subsidiaries from incurring additional debt or other liabilities, including secured debt. Following a qualified initial public offering, the Convertible Notes may be converted into common shares of the initial public offering issuer at the option of the noteholders.

The Convertible Notes also provide for cash redemption upon a change in control event at the option of the holders at a premium, which as of September 30, 2017 ranged from 142.9% to 153.8% of the principal amount of the Convertible Notes, depending on the change of control date relative to the date issued. The Convertible Notes are not redeemable prior to a change of control or the closing of a Qualified PO. If the closing of a Qualified PO occurs, we have the option to redeem all of the Convertible Notes that were not converted at a price equal to 100.0% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any.

In March 2017, we retired $11.1 million of outstanding principal and accrued and unpaid interest associated with Convertible Notes contributed to us by the Member. Additionally, we wrote off $0.8 million of associated discounts and embedded derivative liability, which resulted in an increase to equity of $11.9 million.

Second Lien Term Loans

In September 2013, we entered into the Second Lien Term Loans due September 30, 2018. In April 2017, the outstanding $1.290 billion in principal of the Second Lien Term Loans was repaid using proceeds from the issuance of our 2022 Notes as discussed herein. We paid approximately $1.372 billion in cash, consisting of $1.290 billion applied to the outstanding principal balance, $71.0 million in early redemption fees and $11.0 million in accrued and unpaid interest, resulting in a loss of $108.4 million, including the write-off of unamortized debt issuance costs and discounts, for the nine months ended September 30, 2017.

Contractual Obligations and Off-Balance Sheet Arrangements

We occasionally enter into arrangements that can give rise to contractual obligations and off-balance sheet commitments, such as pipeline transportation commitments, drilling rig commitments, and various other commitments in the ordinary course of business. See Note 8 of the notes to our condensed consolidated financial statements for further details of our commitments.

Adopted and Recently Issued Accounting Pronouncements

See Note 1 of the notes to our condensed consolidated financial statements for a description of recent accounting pronouncements.

Results of Operations

General. For the three and nine months ended September 30, 2017, we had net losses of $25.9 million and $116.9 million, respectively, on total revenues of $203.1 million and $703.9 million, respectively. This compares to net losses of $101.9 million and $25.0 million, respectively, on total revenues of $106.9 million and $235.4 million for the same periods in 2016. Net loss for the three months ended September 30, 2017 was primarily driven by losses on commodity derivatives. Net loss for the nine months ended September 30, 2017 was primarily driven by the $114.1 million loss related to the debt transactions in April 2017.

Natural Gas Sales. During the three and nine months ended September 30, 2017, natural gas sales were $177.6 million and $457.8 million, respectively, compared to $73.2 million and $167.6 million for the same periods in 2016. For the three and nine months ended September 30, 2017, we sold 66.5 and 156.0 bcf of natural gas at a weighted average price of $2.67 and $2.93 per mcf, respectively (excluding the effect of derivatives), compared to 29.7 and 75.2 bcf, sold in the same periods for 2016 at weighted average prices of $2.46 and $2.23 per mcf, respectively (excluding the effect of derivatives). The $104.4 million increase in natural gas sales (excluding the effect of derivatives) for the three months ended September 30, 2017 compared to the same period in 2016 was driven by a 124% increase in natural gas production, as well as a 9% increase in average sales prices received for natural gas from the three months ended September 30, 2016. The $290.2 million increase in natural gas sales (excluding the effect of derivatives) for the nine months ended September 30, 2017 compared to the same period in 2016 was driven by a 107% increase in natural gas production, as well as a 31% increase in average sales prices received for natural gas from the nine months ended September 30, 2016.

Gains and losses from our natural gas derivatives resulted in a net decrease in natural gas revenues of $10.7 million and a net increase in natural gas revenues of $90.2 million for the three and nine months ended September 30, 2017, respectively, and a net increase in natural gas revenues of $8.8 million and a net decrease in natural gas revenues of $7.5 million for the three and nine months ended September 30, 2016, respectively.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our three and nine months ended September 30, 2017 production levels and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would result in an increase or decrease in sales and cash flows of approximately $6.6 million and $15.6 million, respectively.

Oil Sales. During the three and nine months ended September 30, 2017, oil sales were $25.6 million and $87.4 million, respectively, compared to $16.9 million and $50.9 million for the same periods in 2016. For the three and nine months ended September 30, 2017, we sold 604 and 2,006 mbbls of oil at a weighted average price of $42.40 and $43.58 per bbl, respectively (excluding the effect of derivatives), compared to 432 and 1,650 mbbls, sold in the same periods for 2016 at weighted average prices of $39.05 and $30.84 per bbl, respectively (excluding the effect of derivatives). The $8.7 million increase in oil sales (excluding the effect of derivatives) for the three months ended September 30, 2017 compared to the same period in 2016 was driven by a 40% increase in oil production, as well as a 9% increase in average sales prices received for oil from the three months ended September 30, 2016. The $36.5 million increase in oil sales (excluding the effect of derivatives) for the nine months ended September 30, 2017 compared to the same period in 2016 was driven by a 22% increase in oil production, as well as a 41% increase in average sales prices received for oil from the nine months ended September 30, 2016.

Gains and losses from our oil derivatives resulted in a net decrease in oil revenues of $6.5 million and a net increase in oil revenues of $15.0 million for the three and nine months ended September 30, 2017, respectively, and a net increase in oil revenues of $0.5 million and a net decrease in oil revenues of $1.2 million for the three and nine months ended September 30, 2016, respectively.

A change in oil prices has a direct impact on our sales and cash flows. Assuming our three and nine months ended September 30, 2017 production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of oil sold would result in an increase or decrease in sales and cash flows of approximately $0.6 million and $2.0 million, respectively.

NGL Sales. During the three and nine months ended September 30, 2017, NGL sales were $17.0 million and $53.5 million, respectively, compared to $7.6 million and $25.7 million for the same periods in 2016. For the three and nine months ended September 30, 2017, we sold 779 and 2,519 mbbls of NGL at a weighted average price of $21.89 and $21.22 per bbl, respectively (excluding the effect of derivatives), compared to 655 and 2,065 mbbls, sold in the same periods for 2016 at weighted average prices of $11.54 and $12.46 per bbl, respectively (excluding the effect of derivatives). The $9.4 million increase in NGL sales (excluding the effect of derivatives) for the three months ended September 30, 2017 compared to the same period in 2016 was driven by a 19% increase in NGL production, as well as a 90% increase in average sales prices received for NGL from the three months ended September 30, 2016. The $27.8 million increase in NGL sales (excluding the effect of derivatives) for the nine months ended September 30, 2017 compared to the same period in 2016 was driven by a 22% increase in NGL production, as well as a 70% increase in average sales prices received for NGL from the nine months ended September 30, 2016.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our three and nine months ended September 30, 2017 production levels and without considering the effect of derivatives, an increase or decrease of $1.00 per barrel of NGL sold would result in an increase or decrease in sales and cash flows of approximately $0.8 million and $2.5 million, respectively.

Lease Operating Expenses. Lease operating expenses were $10.2 million and $24.7 million for the three and nine months ended September 30, 2017, respectively, compared to $3.0 million and $19.6 million for the same periods in 2016. On a per unit basis, lease operating expenses were $0.14 and $0.13 per mcfe for the three and nine months ended September 30, 2017, respectively, compared to $0.08 and $0.20 per mcfe for the same periods in 2016. The per unit decrease for the nine months ended September 30, 2017 compared to the same period in 2016 was primarily the result of operating efficiencies, including preventative maintenance programs and improved well management, facility construction and artificial lift techniques.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $77.7 million and $227.1 million for the three and nine months ended September 30, 2017, respectively, compared to $44.5 million and $140.9 million for the same periods in 2016. On a unit-of-production basis, gathering, processing and transportation expenses were $1.04 and $1.24 per mcfe for the three and nine months ended September 30, 2017, respectively, compared to $1.23 and $1.44 per mcfe for the same periods in 2016. The per unit decrease for the three and nine months ended September 30, 2017 compared to the same periods in 2016, was due to increased production in 2017, which reduced expense related to unused firm transportation.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $3.5 million and $9.7 million for the three and nine months ended September 30, 2017, respectively, compared to $1.9 million and $6.0 million for the same periods in 2016. On a unit-of-production basis, production and ad valorem taxes were $0.05 per mcfe for both the three and nine months ended September 30, 2017, respectively, compared to $0.05 and $0.06 per mcfe for the same periods in 2016. In general, production taxes are calculated using volume based formulas that produce higher absolute costs as production increases. The per unit decrease for the nine months ended September 30, 2017 compared to the same periods in 2016, was the result of ad valorem taxes lagging behind an increase in producing wells in 2017.

Exploration Expenses. Exploration expenses for the three and nine months ended September 30, 2017 were $22.9 million and $137.9 million, respectively, compared to $60.6 million and $124.9 million for the same periods in 2016. We impaired $22.6 million and $136.7 million of individually insignificant unproved natural gas and oil properties for the three and nine months ended September 30, 2017, respectively, compared to $57.1 million and $108.9 million for the same periods in 2016. We also had rig standby or other charges of nominal amounts for both the three and nine months ended September 30, 2017, and $2.0 million and $11.1 million for the same periods in 2016, respectively.

General and Administrative Expenses, Including Related Party. General and administrative expenses, including related party expenses, were $9.4 million and $30.4 million for the three and nine months ended September 30, 2017, respectively, compared to $10.6 million and $28.8 million for the same periods in 2016. On a unit-of-production basis, general and administrative expenses, including related party expenses, were $0.13 and $0.17 per mcfe for the three and nine months ended September 30, 2017, respectively, compared to $0.29 and $0.30 per mcfe for the same periods in 2016. The combined per unit expense decrease was primarily due to increased production in 2017.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) of natural gas and oil properties for the three and nine months ended September 30, 2017 was $80.0 million and $208.4 million, respectively, compared to $61.9 million and $170.8 million for the same periods in 2016. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves for the three and nine months ended September 30, 2017 was $1.07 and $1.14 per mcfe, respectively, compared to $1.71 and $1.75 per mcfe for the same periods in 2016. The per unit decrease was the result of an increase in total proved reserves.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets for the three and nine months ended September 30, 2017 was $0.5 million and $1.4 million, respectively, compared to $0.5 million and $1.4 million for the same periods in 2016. On a unit-of-production basis, depreciation and amortization of other assets was $0.01 per mcfe for the three and nine months ended September 30, 2017 compared to $0.01 per mcfe for the same periods in 2016. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. Our other property and equipment consist mainly of field offices and other corporate assets.

Impairment of Other Property and Equipment. During the nine months ended September 30, 2016, we recorded a $2.2 million impairment associated with pipeline and gathering assets determined to no longer be in service and deemed obsolete. During the nine months ended September 30, 2017, no such impairment was recorded.

Interest Expense. Interest expense for the three and nine months ended September 30, 2017 was $23.7 million and $46.5 million, respectively, compared to $23.5 million and $76.3 million, for the same periods in 2016, detailed as follows along with average borrowings:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
		($ in thousands)		
Interest expense on Senior Notes	$ 37,500	$ —	$ 72,917	$ —
Interest expense on Second Lien Term Loans	—	42,002	37,502	123,679
Interest expense on Convertible Notes	892	785	2,606	9,895
Interest expense on Credit Facilities [(a)]	4,947	—	9,479	—
Interest expense on Junior Lien Debt	—	28,587	—	80,059
Interest expense on pipeline commitments	880	1,884	2,998	2,500
Amortization of debt discount and issuance costs	4,536	8,310	17,993	33,006
Capitalized interest	(25,087)	(58,040)	(96,978)	(172,866)
Total interest expense, net	$ 23,668	$ 23,528	$ 46,517	$ 76,273
Average Senior Notes borrowings	$ 1,500,000	$ —	$ 978,022	$ —
Average Second Lien Term Loans borrowings	$ —	$ 1,284,088	$ 448,993	$ 1,277,659
Average Convertible Notes borrowings	$ 67,419	$ 75,324	$ 69,631	$ 174,248
Average Junior Lien borrowings	$ —	$ 746,182	$ —	$ 657,168
Average Credit Facilities borrowings	$ —	$ —	$ —	$ —

(a) Includes commitment, participation and fronting fees associated with the 2017 Credit Facility.

The nominal increase in interest expense and amortization of debt discounts and issuance costs for the three months ended September 30, 2017 compared to the same period in 2016, was primarily due to an increase in interest expense associated with the issuance of the 2022 Notes and 2017 Credit Facility in April 2017 and a decrease in capitalized interest, which was largely offset by a decrease in interest expense associated with the Second Lien Term Loans due to retiring the outstanding principal in April 2017 and a decrease in interest expense on junior lien debt due to the repurchase and retirement of all of the $789.3 million of outstanding principal associated with the junior lien debt and accrued and unpaid interest in November 2016. The decrease in interest expense and amortization of debt discounts and issuance costs for the nine months ended September 30, 2017 compared to the same period in 2016 was primarily due to a decrease in interest expense associated with the Second Lien Term Loans as a result of the retirement of all of the outstanding $1.290 billion in principal in April 2017, the repurchase and retirement of all of the $789.3 million of outstanding principal associated with the junior lien debt and accrued and unpaid interest in November 2016, as well as the redemption of Convertible Notes in April 2016, offset by an increase in interest expense associated with the issuance of the 2022 Notes and 2017 Credit Facility in April 2017 and a reduction in capitalized interest as a result of a lower weighted average interest rate.

Acquisition Obligation Accretion Expense. Acquisition obligation accretion expense for the three and nine months ended September 30, 2017 was $1.0 million and $3.5 million, respectively, compared to $2.3 million and $8.5 million for the same periods in 2016. This obligation relates to the carried interest from certain asset acquisitions that require us to pay the seller's retained share of development costs for certain wells and other development operations that occur within an area of mutual interest as defined in the agreement. This obligation was discounted using an 11% discount rate for the three and nine months ended September 30, 2017 and 2016, to reflect the imputation of interest.

Change in Fair Value of Embedded Derivative. The change in fair value of the embedded derivative in the Convertible Notes resulted in losses of $0.6 million and $18.6 million for the three and nine months ended September 30, 2017, respectively, compared to no gain or loss for the three months ended September 30, 2016 and an $8.2 million gain for the nine months ended September 30, 2016. In general, increases in the fair value of the associated debt, the probability of early exit, expected volatility, remaining time to maturity and the credit spread between the Convertible Notes and the risk-free rate would increase the value of the embedded derivative liability. Alternatively, decreases in these factors, including a decrease in the outstanding principal amount of Convertible Notes, would decrease the value of the embedded derivative liability.

(Losses) Gains on Purchases or Exchanges of Debt. We recognized a loss on purchases or exchanges of debt of $114.1 million for the nine months ended September 30, 2017 related to the repayment and retirement of the Second Lien Term Loans and the retirement of the 2016 Credit Facility in April 2017. During the three months ended September 30, 2016, we recognized a loss on purchases or exchanges of debt of $0.3 million primarily consisting of a loss on the redemption of the New Convertible Notes. During the nine months ended September 30, 2016, we recognized a gain on purchases or exchanges of debt of $304.8 million primarily in connection with the Exchange Offer and subsequent redemption of the Convertible Notes in February and April 2016, respectively.

Quantitative and Qualitative Disclosure 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 risk. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas, oil and NGL prices, customer credit 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 exposures.

Commodity Demand and Price Risk

Our primary market risk exposure is in the price we receive for our natural gas, oil and NGL production. Realized pricing is primarily driven by spot regional market prices applicable to our natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production is volatile and unpredictable, and we expect this volatility to continue in the future. The prices we expect to receive for production will depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price. The demand for natural gas, oil and NGL is susceptible to volatility related to, among other factors, the level of global economic activity and may also fluctuate depending on the performance of specific industries. We expect that a decrease in economic activity, in the United States and elsewhere, would adversely affect demand for the natural gas, oil and NGL we expect to produce.

To mitigate our exposure to adverse commodity price changes, we have periodically entered into commodity derivative instruments. We do not enter into commodity derivative instruments for speculative or trading purposes. Under the terms of a swap, we receive a fixed price for our natural gas or oil production and pay a variable market price to the counterparty. Options are used to establish a floor price (put), a ceiling price (call) or a floor and a ceiling price (collar) for expected future production. The sold call establishes the maximum price that we will receive for contracted commodity volumes. The purchased put establishes the minimum price that we will receive for the contracted volumes. Given that our natural gas is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX, basis swaps may be periodically used to fix or float the differential between product prices at one market location versus another.

The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of September 30, 2017 and the contracted weighted average natural gas prices:

	Volume (mmbtu/d)	Weighted Average Price: Swap fixed price	Sold call strike price ($/mmbtu)	Purchased put strike price
Natural gas:				
Swaps:				
Remaining in 2017	725,000	$ 3.16		
2018	892,000	$ 3.03		
2019	683,000	$ 2.92		
2020	40,000	$ 2.87		
Basis Swaps:				
Remaining in 2017	84,000	$ (0.11)		
2018	107,500	$ (0.15)		
2019	102,500	$ (0.15)		
Collars:				
2018	134,000		$ 3.27	$ 3.00
Call options:				
Remaining in 2017	50,000		$ 3.25	
2018	50,000		$ 3.25	

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of September 30, 2017 and the contracted weighted average oil prices:

	Average Volume (bbl/d)	Weighted Average NYMEX ($/bbl)
Oil :		
Swaps:		
Remaining in 2017	5,300	$ 54.19
2018	3,500	$ 53.42
2019	1,000	$ 50.94

At September 30, 2017, we have hedged approximately 76% of our remaining estimated 2017 natural gas production and 75% of our remaining estimated 2017 oil production. Additionally, we have hedged approximately 63% of our estimated 2018 natural gas production and 64% of our estimated 2018 oil production. At September 30, 2017, we had a net liability derivative position of $0.5 million, related to our fixed price commodity swaps.

Customer Credit Risk

We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables. The following table provides the concentration of sales to individual purchasers that constitute 10% or more of our revenues, before the effects of derivatives:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	2017	2016
Tenaska Marketing Ventures	19%	47%	25%	48%
Sequent Energy Management, L.P.	30%	12%	25%	—
Marathon Petroleum Company, L.P.	—	14%	—	18%
DTE Energy Trading, Inc.	—	10%	—	—

If our largest customers decided to stop purchasing natural gas from us, our revenues could decline and our operating results and financial condition could be harmed. Although a substantial portion of our production is purchased by these major customers, we do not believe the loss of one or more customers would have a material adverse effect on our business, as other customers or markets would be accessible to us.

We also have joint interest receivables, which arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells, nor can we require these entities to post collateral to us if these entities are judged to have sub-standard credit. We historically have not incurred losses on our joint interest receivables.

Interest Rate Risk

At September 30, 2017, the Convertible Notes bore interest at a fixed rate of 5.5% and the 2022 Notes bore interest at a fixed rate of 10.0%. The 2017 Credit Facility incurred participation fees associated with outstanding letters of credit at a variable tiered rate based on facility usage plus the 1-month LIBOR exposing us to interest rate risk. A 1.0% increase in the LIBOR for the three and nine months ended September 30, 2017 would have resulted in an estimated $1.1 million and $1.9 million, respectively, increase in interest expense on the 2017 Credit Facility, which was established April 5, 2017. We had no outstanding interest rate derivatives at September 30, 2017.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the year ended 2016 or for the nine months ended September 30, 2017. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as natural gas, oil and NGL prices increase and drilling activity in our areas of operations increases.