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

Ascent Resources Utica Holdings, LLC

As of September 30, 2018 and December 31, 2017 and for the Three and Nine Months Ended September 30, 2018 and 2017.

Explanatory Note

Ascent Resources Utica Holdings, LLC (ARUH), together with its wholly-owned subsidiaries (collectively, the Company), is issuing this amended report (Amended Report) to restate its unaudited condensed consolidated financial statements, related footnote disclosures and Management's Discussion and Analysis of Financial Condition and Results of Operations as of September 30, 2018 and for the three and nine months ended September 30, 2018 (Original Report) to correct errors in accounting for incentive units as described below.

This Amended Report is presented as of the issuance date of the Original Report and does not reflect events occurring after that date, or modify or update disclosures in any way other than as required to reflect the restatement described in further detail in Note 2 of this report.

Management of the Company has determined that incentive units issued by certain of the Company's affiliates did not meet the requirements for liability classification in accordance with ASC 718 *Compensation - Stock Compensation* (ASC 718), and alternatively, met either the requirements for equity classification under ASC 718 or the requirements for treatment in accordance with ASC 710, *Compensation* (ASC 710). The most notable difference between the accounting treatment of liability-classified awards versus equity-classified awards under ASC 718 is the measurement basis for recognition of compensation cost. Equity-classified awards are measured on the grant date at fair value and compensation cost is recognized over the requisite service period, whereas liability-classified awards are remeasured each reporting period to the then current fair value and compensation cost is recognized for the change in fair value and for the incremental vesting of incentive units until the awards are settled.

The Company has restated the condensed consolidated financial statements as of September 30, 2018 and for the three and nine months ended September 30, 2018 to correct the accounting for certain of these incentive units from liability-classified awards under ASC 718 to equity-classified awards under ASC 718. Additionally, the Company has reversed accruals for other units previously accounted for as liability-classified awards under ASC 718. Compensation cost for these units will be recognized when a distribution on the units becomes probable, in accordance with ASC 710. The principal effect of the restatement is a decrease to our incentive unit expense of $15.9 million for the three months ended September 30, 2018 and a decrease of $24.5 million for the nine months ended September 30, 2018, which represents a cumulative adjustment for compensation cost recognized since the initial issuances of the incentive units in the fourth quarter of 2016. The restated incentive unit expense is presented within general and administrative expense in these restated financial statements. The impact for all prior interim and annual periods was not material. This correction does not affect previously reported net cash provided by (used in) operating, investing or financing activities, although certain presentation changes have been made in our condensed consolidated statement of cash flows to correspond to the statement of operations.

ASCENT RESOURCES UTICA HOLDINGS, LLC
INDEX TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(RESTATED)

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

($ in thousands)	September 30, 2018 (Restated)	December 31, 2017
Current Assets:		
Cash and cash equivalents	$ 10,868	$ 119,215
Accounts receivable – natural gas, oil and NGL sales	277,995	146,788
Accounts receivable – joint interest and other	58,372	40,934
Short-term derivative assets	43,643	76,439
Other current assets	4,782	3,057
Total Current Assets	395,660	386,433
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	6,732,504	4,441,612
Other property and equipment	26,986	19,625
Less: accumulated depreciation, depletion and amortization	(1,026,649)	(678,274)
Property and Equipment, net	5,732,841	3,782,963
Other Assets:		
Long-term derivative assets	40,719	31,441
Other long-term assets	17,491	13,032
Total Assets	$ 6,186,711	$ 4,213,869
Current Liabilities:		
Accounts payable	$ 125,652	$ 75,665
Revenue payable	138,031	63,211
Accrued interest	81,705	42,438
Short-term derivative liabilities	52,205	8,660
Acquisition obligation	18,791	60,083
Other current liabilities	292,646	200,100
Total Current Liabilities	709,030	450,157
Long-Term Liabilities:		
Long-term debt, net	2,312,635	1,564,774
Long-term derivative liabilities	64,282	4,869
Other long-term liabilities	10,129	11,569
Total Long-Term Liabilities	2,387,046	1,581,212
Commitments and contingencies (Note 9)		
Member's Equity	3,090,635	2,182,500
Total Liabilities and Member's Equity	$ 6,186,711	$ 4,213,869

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,	
	2018	2017	2018	2017
($ in thousands)	(Restated)		(Restated)	
Revenues:				
Natural gas	$ 364,580	$ 177,646	$ 884,857	$ 457,797
Oil	49,064	25,609	95,997	87,409
NGL	33,634	17,047	68,077	53,474
Commodity derivative (loss) gain	(43,000)	(17,248)	(111,370)	105,185
Total Revenues	404,278	203,054	937,561	703,865
Operating Expenses:				
Lease operating expenses	11,393	10,174	34,427	24,650
Gathering, processing and transportation expenses	176,726	77,660	456,605	227,053
Production and ad valorem taxes	7,512	3,467	15,665	9,714
Exploration expenses	39,030	22,936	115,937	137,868
General and administrative expenses	11,656	1,273	37,082	3,724
General and administrative expenses – related party	—	8,148	—	26,640
Acquisition expenses	9,130	—	9,130	—
Natural gas and oil depreciation, depletion and amortization	135,853	80,034	342,446	208,405
Depreciation and amortization of other assets	997	487	2,882	1,435
Total Operating Expenses	392,297	204,179	1,014,174	639,489
Income (Loss) from Operations	11,981	(1,125)	(76,613)	64,376
Other (Expense) Income:				
Interest expense, net	(25,908)	(23,668)	(65,465)	(46,517)
Acquisition obligation accretion expense	(137)	(967)	(1,030)	(3,531)
Change in fair value of embedded derivative	8,503	(633)	14,161	(18,603)
Losses on purchases or exchanges of debt	—	—	—	(114,052)
Other income	482	489	312	1,383
Total Other Expense	(17,060)	(24,779)	(52,022)	(181,320)
Net Loss	$ (5,079)	$ (25,904)	$ (128,635)	$ (116,944)

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)

($ in thousands)	Nine Months Ended September 30, 2018 (Restated)
Balance, beginning of period	$ 2,182,500
Contributions from Member	568,201
Contributions from Member - non-cash	468,569
Net loss	(128,635)
Balance, end of period	$ 3,090,635

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)

($ in thousands)	Nine Months Ended September 30, 2018 (Restated)	2017
Cash Flows from Operating Activities:		
Net loss	$ (128,635)	$ (116,944)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	345,328	209,840
Change in fair value of commodity derivatives	132,892	(96,042)
Impairment of unproved natural gas and oil properties	113,816	136,738
Non-cash interest expense	12,790	—
Acquisition obligation accretion expense	1,030	3,531
Change in fair value of embedded derivative	(14,161)	18,603
Losses on purchases or exchanges of debt	—	114,052
Other	(1,298)	(2)
Changes in operating assets and liabilities:		
Increase in accounts receivable and other assets	(154,591)	(54,221)
Increase in accounts payable, liabilities and other	200,120	84,322
Net Cash Provided by Operating Activities	507,291	299,877
Cash Flows from Investing Activities:		
Drilling and completion costs	(635,434)	(434,087)
Acquisitions of natural gas and oil properties	(1,294,821)	(249,646)
Proceeds from divestitures of natural gas and oil properties	6,564	—
Deposit on natural gas and oil property acquisition	—	(6,200)
Reductions in deposits on pipeline capacity	—	147,715
Additions to other property and equipment	(1,424)	(140)
Proceeds from sale of other property and equipment	175	13
Net Cash Used in Investing Activities	(1,924,940)	(542,345)
Cash Flows from Financing Activities:		
Proceeds from credit facility borrowings	1,035,000	—
Repayment of credit facility borrowings	(285,000)	—
Proceeds from issuance of long-term debt, net	—	1,466,250
Repayment of long-term debt	—	(1,290,264)
Cash paid for debt issuance costs	(8,899)	(14,366)
Cash paid for debt prepayment costs	—	(70,999)
Contributions from Member	568,201	132,000
Net Cash Provided by Financing Activities	1,309,302	222,621
Net Decrease in Cash and Cash Equivalents	(108,347)	(19,847)
Cash and Cash Equivalents, Beginning of Period	119,215	268,493
Cash and Cash Equivalents, End of Period	$ 10,868	$ 248,646
Supplemental disclosures of cash flow information:		
Interest paid, net of capitalized interest and interest paid in kind	$ 12,259	$ 7,625
Supplemental disclosures of significant non-cash investing and financing activities:		
Increase in accrued capital expenditures	$ 49,776	$ 54,028
Contributions from Member	$ 468,569	$ 11,942

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 Company is engaged in the acquisition, exploration, development, production and operation of natural gas and oil properties located in the Utica Shale in Ohio (Utica Shale).

The accompanying unaudited condensed consolidated financial statements and notes of 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 (First Reserve). 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, 2017.

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.

Business Segment Information

The Company evaluated how it is organized and managed and has identified only one operating segment, which is the exploration, development and production of natural gas, oil, and natural gas liquids (NGL) in the United States. Operating segments are defined as components of an enterprise that engage in business activities from which it may earn revenues and incur expenses for which discrete operational financial information is available and this information is regularly reviewed by the chief operating decision makers to make decisions about the allocation of resources and assessment of performance.

The Company has a single, company-wide management team that administers all properties as a whole rather than by distinct operating segments. The Company measures financial performance as a single enterprise and not on a geographical basis.

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.

Reclassifications

Certain reclassifications have been made to the Company's 2017 unaudited condensed consolidated financial statements to conform to the presentation used for the 2018 unaudited condensed consolidated financial statements.

Restatement of Financial Statements

See Note 2 for a discussion of the restatement of the accompanying unaudited condensed consolidated financial statements.

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,	
	2018	2017	2018	2017
Tenaska Marketing Ventures	23%	19%	23%	25%
Sequent Energy Management, L.P.	14%	30%	17%	25%

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 August 2018, the FASB issued ASU 2018-13, *Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement (Topic 820)*. The amendments in this ASU remove, modify and add to the disclosure requirements for fair value measurements. The new standard clarifies that entities should disclose information about the uncertainty of fair value measurements as of the reporting date. This amendment is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019 for both public and non-public entities. The guidance on changes in unrealized gains and losses, the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements and the narrative description of measurement uncertainty should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption. All other amendments should be applied retrospectively to all periods presented upon their effective date. Entities are permitted to early adopt any removed or modified disclosures and delay the adoption of the additional disclosures until their effective date. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

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 for public business entities and for periods beginning after December 15, 2018 for non-public entities, though the FASB has permitted entities to adopt one year earlier if they choose (i.e., the original effective date). The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented on 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 in the process of completing its evaluation of the impact of this ASU on its consolidated financial statements 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, among other things, the review of all material revenue contracts within each of the revenue streams identified. The Company has identified expanded revenue disclosures and internal control changes necessary for adoption and is in the process of finalizing documentation of new policies, procedures and controls. The Company will adopt the new standard using 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. Classification of leases as either a finance or operating lease will determine the recognition, measurement and presentation of expenses. This accounting standards update also requires certain quantitative and qualitative disclosures about leasing arrangements. Lessees and lessors can apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented on the financial statements. In July 2018, the FASB issued ASU 2018-11, *Leases (Topic 842), Targeted Improvements*. This ASU would permit an entity to apply a transition method at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption instead of recasting prior year results. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018 for public business entities and for periods beginning after December 15, 2019 for non-public entities, with early adoption permitted. The Company is in the process of evaluating the impact of this ASU on its consolidated financial statements and related disclosures. Based on the Company's preliminary review, the Company expects to have leases with durations greater than twelve months on its balance sheet along with expanded lease disclosures and internal control changes necessary for adoption. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842), Land Easement Practical Expedient for Transition to Topic 842*. This ASU would permit an entity to not apply Topic 842 to land easements and rights-of-way that existed or expired before the effective date of Topic 842 and that were not previously assessed under Topic 840. An entity would continue to apply its current accounting policy for land easements that existed before the effective date of Topic 842. Once an entity adopts Topic 842, it would be applied prospectively to all new (or modified) land easements and rights-of-way to determine whether the arrangement should be accounted for as a lease.

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 for public business entities and for periods beginning after December 15, 2018 for non-public entities, with early adoption permitted, and should be applied retrospectively to all periods presented. The Company adopted this guidance in the fourth quarter of 2017. The primary effect from adoption is that all payments for debt prepayment or debt extinguishment costs, excluding accrued interest, are classified as cash outflows for financing activities. A retrospective change to the September 30, 2017 condensed consolidated statement of cash flows as previously presented is required pursuant to this standard, which resulted in an increase to losses on purchases or exchanges of debt in cash flows from operating activities and an increase to cash paid for debt prepayment costs in cash flows from financing activities of $71.0 million.

2. Restatement of Previously Issued Financial Statements

Overview

This Amended Report is presented as of the issuance date of the Original Report to correct errors in accounting for incentive units as described below and does not reflect events occurring after issuance date of the Original Report, or modify or update disclosures in any way other than as required to reflect the restatement described below.

In order to provide incentives to certain officers, employees and professionals of the Company, the Company and certain of its affiliates established incentive compensation plans and awarded incentive units to individuals for past and future performance of services to the Company. Holders of incentive units are entitled to potential future distributions to be funded by specific members of the Parent, which are triggered after specified members of the Parent recover their capital contributions and achieve certain investment return thresholds. These incentive units are intended to constitute profits interests.

Management of the Company has determined that incentive units issued by certain of the Company's affiliates did not meet the requirements for liability classification in accordance with ASC 718, and alternatively, met either the requirements for equity classification under ASC 718 or the requirements for treatment in accordance with ASC 710. The most notable difference between the accounting treatment of liability-classified awards versus equity-classified awards under ASC 718 is the measurement basis for recognition of compensation cost. Equity-classified awards are measured on the grant date at fair value and compensation cost is recognized over the requisite service period, whereas liability-classified awards are remeasured each reporting period to the then current fair value and compensation cost is recognized for the change in fair value and for the incremental vesting of incentive units until the awards are settled.

The Company has restated the condensed consolidated financial statements as of September 30, 2018 and for the three and nine months ended September 30, 2018 to correct the accounting for certain of these incentive units from liability-classified awards under ASC 718 to equity-classified awards under ASC 718. Additionally, the Company has reversed accruals for other units previously accounted for as liability-classified awards under ASC 718. Compensation cost for these units will be recognized when a distribution on the units becomes probable, in accordance with ASC 710. The principal effect of the restatement is a decrease to our incentive unit expense of

$15.9 million for the three months ended September 30, 2018 and a decrease of $24.5 million for the nine months ended September 30, 2018, which represents a cumulative adjustment for compensation cost recognized since the initial issuances of the incentive units in the fourth quarter of 2016. The restated incentive unit expense is presented within general and administrative expense in these restated financial statements. The impact for all prior interim and annual periods was not material. This correction does not affect previously reported net cash provided by (used in) operating, investing or financing activities, although certain presentation changes have been made in our condensed consolidated statement of cash flows to correspond to the statement of operations.

Financial Statement Presentation

In this Amended Report, the Company is restating the condensed consolidated financial statements as of September 30, 2018 and for the three and nine months ended September 30, 2018. The effect of the restatement on the condensed consolidated statements of operations, condensed consolidated balance sheets, condensed consolidated statement of Member's equity and condensed consolidated statement of cash flows are as follows:

	Three Months Ended September 30, 2018		Nine Months Ended September 30, 2018	
($ in thousands)	(Previously Reported)	(As Restated)	(Previously Reported)	(As Restated)
Condensed Consolidated Statements of Operations:				
General and administrative expenses	$ 11,474	$ 11,656	$ 38,507	$ 37,082
Incentive units expense	$ 16,102	$ —	$ 23,119	$ —
Total Operating Expenses	$ 408,217	$ 392,297	$ 1,038,718	$ 1,014,174
(Loss) Income from Operations	$ (3,939)	$ 11,981	$ (101,157)	$ (76,613)
Net Loss	$ (20,999)	$ (5,079)	$ (153,179)	$ (128,635)

	September 30, 2018	
($ in thousands)	(Previously Reported)	(As Restated)
Condensed Consolidated Balance Sheets:		
Long-Term Liabilities		
Other long-term liabilities	$ 36,645	$ 10,129
Total Long-Term Liabilities	$ 2,413,562	$ 2,387,046
Member's Equity	$ 3,064,119	$ 3,090,635

	September 30, 2018	
($ in thousands)	(Previously Reported)	(As Restated)
Condensed Consolidated Statement of Member's Equity:		
Contributions from Member - non-cash	$ 466,597	$ 468,569
Net loss	$ (153,179)	$ (128,635)
Balance, end of period	$ 3,064,119	$ 3,090,635

($ in thousands)	September 30, 2018 (Previously Reported)	September 30, 2018 (As Restated)
Condensed Consolidated Statement of Cash Flows:		
Cash Flows from Operating Activities:		
Net loss	$ (153,179)	$ (128,635)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Incentive units expense	$ 23,119	$ —
Other	$ 127	$ (1,298)
Supplemental disclosures of significant non-cash investing and financing activities:		
Contributions from Member	$ 466,597	$ 468,569

The restatement had no impact on net cash provided by (used in) operating, investing or financing activities.

3. Acquisitions and Divestitures

2018 Acquisitions

During the third quarter of 2018, the Company acquired approximately 113,600 net leasehold acres and royalty interests on approximately 69,600 acres of fee minerals upon the closing of the CNX and Hess Acquisition, the Salt Fork Acquisition and the UMD Acquisition, all of which are defined and discussed below.

CNX and Hess Acquisition. On August 30, 2018, the Company acquired producing and non-producing natural gas and oil properties in the Utica Shale, which included approximately 24,000 net leasehold acres, 46,000 acres of unencumbered fee minerals and royalties on 8,400 acres of fee minerals, from CNX Resources Corporation and Hess Corporation (together, the CNX and Hess Acquisition) for consideration of approximately $765.7 million, subject to post-closing adjustments. Funding for the CNX and Hess Acquisition consisted of borrowings under the Credit Facility and cash proceeds contributed to the Company from a common equity offering by the Parent. In connection with the CNX and Hess Acquisition, the Company paid approximately $6.8 million of acquisition expenses, consisting primarily of legal services, due diligence expenses and filing fees, which are presented as acquisition expenses on the condensed consolidated statements of operations.

The CNX and Hess Acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the acquisition date in accordance with FASB ASC 805, *Business Combinations*. The fair value of the assets acquired and liabilities assumed was estimated using assumptions that represent Level 3 inputs. See Note 7, *Fair Value Measurement on a Non-recurring Basis,* for additional discussion of the fair value estimates. No goodwill or bargain purchase gain was recognized in conjunction with the acquisition. The following table presents the fair value of the assets acquired and liabilities assumed in the CNX and Hess Acquisition as of the acquisition date:

($ in thousands)	Assets Acquired/ (Liabilities Assumed)	
Consideration:		
Cash, net of purchase price adjustments	$	765,709
Assets acquired:		
Proved natural gas and oil properties	$	400,825
Unproved natural gas and oil properties		366,041
Liabilities assumed:		
Other current liabilities		(817)
Asset retirement obligations		(340)
Fair Value of Net Assets Acquired	$	765,709

Salt Fork Acquisition. In August 2018, the Company acquired primarily non-producing natural gas and oil properties in the Utica Shale, which consisted of approximately 23,000 net unproved leasehold acres and approximately 1,000 acres of unencumbered fee minerals, from Salt Fork Resources Employer, LLC (Salt Fork) for $223.0 million (the Salt Fork Acquisition), subject to customary closing adjustments. The Salt Fork Acquisition was funded entirely with common equity issued directly to the seller from the Parent.

UMD Acquisition. On July 13, 2018, the Company acquired producing and non-producing natural gas and oil assets in the Utica Shale, which included approximately 5,400 net leasehold acres and 14,200 acres of unencumbered fee minerals, from Utica Minerals Development, LLC (UMD) for consideration of approximately $501.4 million (the UMD Acquisition), including customary closing adjustments and approximately $238.6 million of common equity issued directly from the Parent. The cash consideration was funded using proceeds contributed to the Company from a common equity offering by the Parent. Upon the closing of the UMD Acquisition in July 2018, the agreements between the Company and UMD discussed in Note 8, *UMD Agreements*, were terminated. In connection with the UMD Acquisition, the Company paid approximately $2.3 million of acquisition expenses, consisting primarily of legal services and filing fees, which are presented as acquisition expenses on the condensed consolidated statements of operations.

The UMD Acquisition qualified as a business combination, and as such, the Company estimated the fair value of these properties as of the acquisition date in accordance with FASB ASC 805, *Business Combinations*. The fair value of the assets acquired and liabilities assumed was estimated using assumptions that represent Level 3 inputs. See Note 7, *Fair Value Measurement on a Non-recurring Basis,* for additional discussion of the fair value estimates. No goodwill or bargain purchase gain was recognized in conjunction with the purchase. The following table presents the fair value of the assets acquired and liabilities assumed in the UMD Acquisition as of the acquisition date:

($ in thousands)		Assets Acquired/ (Liabilities Assumed)
Consideration:		
Cash, net of purchase price adjustments	$	262,842
Equity issued directly from Parent		238,560
Total Consideration	$	501,402
Assets acquired:		
Proved natural gas and oil properties	$	270,271
Unproved natural gas and oil properties		222,311
Commodity derivative assets		8,826
Liabilities assumed:		
Asset retirement obligations		(6)
Fair Value of Net Assets Acquired	$	501,402

2017 Acquisitions and Divestitures

In November 2017, the Company acquired and contemporaneously sold both producing and non-producing natural gas and oil properties located in the Utica Shale in the following series of transactions:

- The Company acquired approximately 16,400 net acres, which included both producing and non-producing natural gas and oil properties (the 2017 Utica Acquisition) for a purchase price of $62.0 million, subject to customary closing adjustments. The Company funded the 2017 Utica Acquisition with funds from the 2017 Utica Divestiture described below. The 2017 Utica Acquisition primarily consisted of non-producing natural gas and oil properties and was accounted for as an asset acquisition. The 2017 Utica Acquisition includes contingent consideration if the price of oil is greater than certain pre-defined prices in 2018, 2019 and 2020. See Note 9, *Contingency*, for further discussion of the contingent liability. A portion of the acquired assets were divested as described below.

- The Company sold a partial interest in producing and non-producing natural gas and oil properties, which included certain properties acquired in the 2017 Utica Acquisition and other properties partially developed by us, for a sales price of $74.6 million, subject to customary closing adjustments (the 2017 Utica Divestiture). The proceeds were used to fund the 2017 Utica Acquisition and for general corporate purposes. As part of the 2017 Utica Divestiture, the Company entered into a development agreement whereby the buyer is required to pay 75.0% of the Company's development costs (Carried Costs) for the development of 34 wells in exchange for 58.5% of the Company's working interest in such wells. The Carried Costs are subject to a ceiling of approximately 105.0% of the mutually agreed upon development costs; after which, the Company is required to pay 90.0% of all of its and the buyer's remaining development costs. As of September 30, 2018, the buyer had carried $31.7 million of the Company's associated development costs.

- In conjunction with the joint venture participation agreement related to an area of mutual interest (AMI) with one of the Company's joint venture partners, the Company sold a partial interest in certain producing and non-producing natural gas and oil properties and 3,270 net acres, which were acquired in the 2017 Utica Acquisition. Additionally, the Company sold approximately 1,130 net unproved acres within the AMI. The total sales price for this transaction was $21.8 million, subject to customary closing adjustments. The consideration for the sales price was a reduction to the Company's carry obligations to the joint venture partner. See Note 9, *Joint Venture Commitment*, for more details of this transaction.

In August 2017, the Company and UMD acquired approximately 10,400 net acres of primarily unproved leasehold in the Utica Shale (the 2017 Acquisition Properties) for a purchase price of $98.0 million, subject to customary closing adjustments. At closing, the Company received an undivided 25% interest in the 2017 Acquisition Properties for $33.4 million with UMD receiving the remaining undivided 75% interest in the 2017 Acquisition Properties. The Company funded this acquisition with $32.0 million that was contributed from the Member and cash on hand. The acquisition consisted primarily of unproved leasehold and was accounted for as an asset acquisition.

4. Property and Equipment

Net property and equipment included the following:

($ in thousands)	September 30, 2018	December 31, 2017
Proved natural gas and oil properties	$ 5,173,876	$ 3,322,876
Unproved natural gas and oil properties	1,558,628	1,118,736
Other property and equipment	26,986	19,625
Total Property and Equipment	6,759,490	4,461,237
Accumulated depreciation, depletion and amortization	(1,026,649)	(678,274)
Property and Equipment, net	$ 5,732,841	$ 3,782,963

5. Long-Term Debt

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

($ in thousands)	September 30, 2018	December 31, 2017
Senior notes due 2022[(a)]	$ 1,500,000	$ 1,500,000
Credit Facility[(b)]	750,000	—
Convertible notes due 2021[(c)]	72,937	69,802
Embedded derivative	9,730	23,891
Net unamortized debt issuance costs	(5,198)	(3,087)
Net unamortized debt discounts	(14,834)	(25,832)
Total Long-Term Debt, net	$ 2,312,635	$ 1,564,774

(a) The interest rate was 10.00% as of September 30, 2018 and December 31, 2017.
(b) The interest rate was 4.43% as of September 30, 2018.
(c) The interest rate was 6.50% and 5.50% as of September 30, 2018 and December 31, 2017, 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 10.00% on April 1 and October 1 of each year, which commenced on October 1, 2017. Net 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 2022 Notes are governed by an indenture containing covenants limiting, among other things, the Company's 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, 2018.

In October 2018, the Company issued $600.0 million in aggregate principal amount of 7.00% senior unsecured notes (2026 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The Company used net proceeds from the issuance of the 2026 Notes to exercise its right to redeem 35%, or $525.0 million, of the aggregate principal amount of the 2022 Notes (the Redemption) at a redemption price equal to 110% of the principal thereof, plus accrued and unpaid interest to, but excluding, the date of the Redemption. The Company used the remaining net proceeds to repay borrowings under the Credit Facility. See Note 11, *Debt Refinancing*, for further discussion.

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 is 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 unsecured debt, and the 2022 Notes 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 1.00% 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 stated annual rate of 10.00%.

Second Lien Term Loans

In September 2013, the Company 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 and extinguished 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 for the nine months ended September 30, 2017, including the write-off of unamortized debt issuance costs and discounts. At the time the Company extinguished the Second Lien Term Loans, the interest rate was 9.50% plus the greater of 1.50% or the 3-month London Interbank Offered Rate (LIBOR).

Credit Facility

In April 2017, the Company entered into a $1.5 billion senior secured revolving credit facility (Credit Facility) with a fully committed borrowing base of $650.0 million and a sublimit for letters of credit of $450.0 million that matures on December 31, 2021. In 2017, the Company executed two amendments to the Credit Facility, which, in aggregate, increased the borrowing base from the initial $650.0 million to a fully committed $925.0 million and increased the sublimit for letters of credit from $450.0 million to $647.5 million. The Company also executed amendments to the Credit Facility in March, June and August of 2018, which, in aggregate, increased the borrowing base from $925.0 million to a fully committed $1.85 billion, increased the sublimit for letters of credit from $647.5 million to $750.0 million, decreased the applicable interest margins by 1.00% and increased the aggregate maximum credit amount from $1.5 billion to $2.5 billion. The amendment to the Credit Facility in August 2018 set the next redetermination for November 2018. The Credit Facility is secured by liens on substantially all of the Company's assets, including its natural gas and oil properties, and the amount available to be borrowed under the Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about April 1 and October 1 of each year based on the estimated value and future net cash flows of the Company's proved natural gas, oil and NGL reserves and the value of its commodity hedge positions. Additionally, the Company may request an interim redetermination of the borrowing base in certain circumstances, including in connection with acquisitions of proved reserves in excess of certain thresholds. As of September 30, 2018, the Company had borrowings of $750.0 million and $423.5 million of letters of credit outstanding under the Credit Facility. As of November 14, 2018, the Company had borrowings of $973.0 million and $404.3 million of letters of credit outstanding. The Credit Facility replaced a prior credit facility established in September 2016, resulting in a write-off of $5.6 million in unamortized debt issuance costs in April 2017.

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 0.50% or (iii) the rate for 1-month Eurodollar loans, plus an applicable margin ranging from 0.75% to 1.75% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 1.75% to 2.75% per annum. Due to the weighted average 1-month LIBOR being 2.18% for the applicable interest periods on the most recent election dates, the Company was subject to a weighted average rate of 4.43% per annum as of September 30, 2018. 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 Credit Facility agreement, the Company is subject to commitment fees payable to the administrative agent at a rate of 0.50% per annum 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 applicable margins, ranging from 1.75% to 2.75% per annum, 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% per annum of the balance of outstanding letters of credit issued. During the three and nine months ended September 30, 2018, the Company incurred $11.4 million and $24.5 million in commitment, participation and fronting fees on letters of credit outstanding and interest on principal borrowings under the Credit Facility, which is presented as interest expense on the condensed consolidated statement of operations.

The 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 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 4.00 to 1.00 for each 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. As of September 30, 2018, the Company was in compliance with the financial covenants of the Credit Facility.

As of September 30, 2018, the Company had incurred $17.2 million in unamortized debt issuance costs associated with the Credit Facility, which are presented as other long-term assets on the condensed consolidated balance sheets.

Convertible Notes

As of September 30, 2018, the Company had $72.9 million in aggregate principal, including accrued and unpaid interest, outstanding under the convertible notes due 2021 (Convertible Notes). The Convertible Notes are subordinate to the 2022 Notes, which rank senior in right of payment. 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 on the condensed consolidated balance sheets. See Note 7, *Fair Value of Derivative Instruments,* 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 3.50%. On March 1, 2016, the interest rate began escalating by 0.50% on each subsequent interest payment date, subject to a maximum interest rate of 6.50% per annum, which was achieved on September 1, 2018, because 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. Upon maturity, unless earlier repurchased 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 65.0% of the public offering price, 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.

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% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any. The Convertible Notes also provide for cash redemption upon a change of control event at the option of the holders at a premium of 153.8% of the principal amount of the Convertible Notes. The Convertible Notes are not redeemable by the holders prior to a change of control or the closing of a Qualified PO.

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.

The $72.9 million in aggregate principal, including accrued and unpaid interest, outstanding under the Convertible Notes as of September 30, 2018, and all future paid in kind interest, will be accreted to a maturity date value of $130.9 million over the scheduled maturity period of the debt.

Interest Expense

Interest expense was comprised of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ in thousands)	2018	2017	2018	2017
Interest expense	$ 50,263	$ 44,221	$ 141,028	$ 125,504
Long-term debt accretion expense	3,795	3,703	10,998	9,929
Deferred debt issuance cost amortization	2,300	831	5,208	8,061
Capitalized interest	(30,450)	(25,087)	(91,769)	(96,977)
Total Interest Expense, net	$ 25,908	$ 23,668	$ 65,465	$ 46,517

6. Commodity Derivative Instruments

The Company uses commodity derivative instruments 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, oil or NGL 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. From time to time, the Company may sell future call options, the premiums from which are used to obtain higher strike prices on swap and collar contracts. 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 are periodically used at the following basis points to fix the differential between product prices at one market location versus another: Chicago (Citygate), Dawn (Ontario), MichCon, Rex Zone 3, TCO and Tetco M-2.

All commodity derivative instruments are recognized at their current fair value as either assets or liabilities on 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. To minimize such risk, the Company's derivative contracts are with multiple counterparties, reducing its exposure to any individual counterparty. Also, the Company only enters into derivative contracts with counterparties that are creditworthy. The creditworthiness of the Company's counterparties is subject to periodic review.

The following table sets forth the average volumes per day associated with the Company's outstanding natural gas derivative instruments as of September 30, 2018 and the contracted weighted average natural gas prices:

		Weighted Average Prices ($/mmbtu)		
	Average Volume (mmbtu/d)	Swap Fixed Price	Sold Call Strike Price	Purchased Put Strike Price
Natural gas:				
Swaps:				
Remaining in 2018	1,218,000	$ 3.00		
2019	1,801,000	$ 2.86		
2020	1,340,000	$ 2.74		
2021	172,500	$ 2.74		
Collars:				
Remaining in 2018	195,000		$ 3.30	$ 2.96
2019	15,000		$ 3.40	$ 2.75
2020	140,000		$ 3.09	$ 2.59
2021	10,000		$ 2.91	$ 2.50
Call options:				
Remaining in 2018	50,000		$ 3.25	
2019	70,500		$ 3.00	
2020	250,000		$ 3.00	
2021	335,000		$ 3.02	
2022	102,500		$ 3.00	
Basis swaps:				
Remaining in 2018	224,500	$ (0.21)		
2019	249,500	$ (0.28)		
2020	70,000	$ (0.54)		

The following table sets forth the average volumes per day associated with the Company's outstanding oil derivative instruments as of September 30, 2018 and the contracted weighted average oil prices:

		Weighted Average Prices ($/bbl)	
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price
Oil:			
Swaps:			
Remaining in 2018	5,600	$ 55.18	
2019	7,750	$ 56.92	
2020	7,500	$ 57.20	
2021	1,000	$ 60.06	
Call options:			
Remaining in 2018	1,000		$ 70.00
2019	2,000		$ 70.00
2020	4,750		$ 70.00
2021	3,500		$ 70.00

The following table sets forth the average volumes per day associated with the Company's outstanding NGL derivative instruments as of September 30, 2018 and the contracted weighted average NGL prices:

		Weighted Average Prices ($/bbl)	
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price
NGL:			
Swaps - Propane:			
Remaining in 2018	2,000	$ 38.69	
2019	3,000	$ 38.33	
2020	1,000	$ 35.07	
Call options - Propane:			
2019	1,600		$ 33.60
2020	3,150		$ 33.60
Swaps - Ethane:			
2019	1,000	$ 17.01	

The following tables summarize the classification and fair value amounts of all commodity derivative instruments on the condensed consolidated balance sheets as of September 30, 2018 and December 31, 2017, as well as the gross recognized derivative assets and liabilities and amounts offset on the condensed consolidated balance sheets:

		September 30, 2018		
($ in thousands)	Condensed Consolidated Balance Sheet Classification	Gross Recognized Fair Value	Amounts Netted on Balance Sheet	Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative assets	$ 74,183	$ (30,540)	$ 43,643
Natural gas, oil and NGL commodity derivatives	Long-term derivative assets	$ 101,744	$ (61,025)	$ 40,719
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative liabilities	$ (82,745)	$ 30,540	$ (52,205)
Natural gas, oil and NGL commodity derivatives	Long-term derivative liabilities	$ (125,307)	$ 61,025	$ (64,282)

		December 31, 2017		
($ in thousands)	Condensed Consolidated Balance Sheet Classification	Gross Recognized Fair Value	Amounts Netted on Balance Sheet	Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas and oil commodity derivatives	Short-term derivative assets	$ 85,522	$ (9,083)	$ 76,439
Natural gas and oil commodity derivatives	Long-term derivative assets	$ 53,275	$ (21,834)	$ 31,441
Derivative liabilities:				
Natural gas and oil commodity derivatives	Short-term derivative liabilities	$ (17,743)	$ 9,083	$ (8,660)
Natural gas and oil commodity derivatives	Long-term derivative liabilities	$ (26,703)	$ 21,834	$ (4,869)

The following table summarizes the effects of commodity derivative instruments on the condensed consolidated statements of operations for the periods presented:

		Three Months Ended September 30,		Nine Months Ended September 30,	
($ in thousands)	Condensed Consolidated Statements of Operations Earnings Caption	2018	2017	2018	2017
Natural gas, oil and NGL commodity derivatives	Commodity derivative (loss) gain	$ (43,000)	$ (17,248)	$ (111,370)	$ 105,185

7. 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, 2018 and December 31, 2017. The fair values of the natural gas, oil and NGL 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 6 for further information on commodity derivative instruments.

	Fair value measurements at September 30, 2018 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 84,362	$ —	$ 84,362
Total	$ —	$ 84,362	$ —	$ 84,362
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 116,487	$ —	$ 116,487
Embedded derivative[(a)]	—	—	9,730	9,730
Total	$ —	$ 116,487	$ 9,730	$ 126,217

(a) This is presented as long-term debt on the condensed consolidated balance sheet as of September 30, 2018.

	Fair value measurements at December 31, 2017 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas commodity derivatives	$ —	$ 107,880	$ —	$ 107,880
Total	$ —	$ 107,880	$ —	$ 107,880
Derivative liabilities:				
Natural gas and oil commodity derivatives	$ —	$ 13,529	$ —	$ 13,529
Embedded derivative[(a)]	—	—	23,891	23,891
Total	$ —	$ 13,529	$ 23,891	$ 37,420

(a) This is presented as long-term debt on the condensed consolidated balance sheet as of December 31, 2017.

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 Convertible Notes 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, 2018	December 31, 2017
Estimated price of Convertible Notes' principal value	138.5%	98.0%
Probability of Qualified PO or change of control	5% - 65% with a total of 95% over the expected term	5% - 50% with a total of 100% over the expected term
Expected term	Between 0 and 3 years	Between 0 and 3 years
Discount rate with and without embedded features	13.9%	11.5%

The following table presents a summary of changes in the fair value of the embedded derivative liability, which is presented as long-term debt on the condensed consolidated balance sheets and as a Level 3 measurement:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ in thousands)	2018	2017	2018	2017
Balance, beginning of period	$ 18,233	$ 22,600	$ 23,891	$ 5,403
Change due to purchases or exchanges of debt	—	—	—	(773)
Change in fair value[(a)]	(8,503)	633	(14,161)	18,603
Balance, end of period	$ 9,730	$ 23,233	$ 9,730	$ 23,233

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

Fair Value of Debt

The carrying amounts and estimated fair values of long-term debt as of September 30, 2018 and December 31, 2017 are shown in the table below. The fair values were estimated using Level 2 market data inputs. See Note 5 for further information regarding long-term debt.

	September 30, 2018		December 31, 2017	
($ in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
2022 Notes	$ 1,469,602	$ 1,687,500	$ 1,467,465	$ 1,608,750
Credit Facility	750,000	750,000	—	—
Convertible Notes	83,303	100,473	73,418	67,175
Total	$ 2,302,905	$ 2,537,973	$ 1,540,883	$ 1,675,925

Fair Value Measurement on a Non-recurring Basis

The Company used a discounted cash flow model to estimate the fair value of the natural gas and oil properties acquired in business combinations. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of natural gas and oil properties include the Company's estimates of (i) quantities of natural gas and oil reserves, (ii) future commodity prices, (iii) future operating and development costs, (iv) projections of future timing and rates of production, (v) reserve risk adjustments and (vi) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates. The asset retirement obligations assumed as part of the business combinations were estimated using the same assumptions and methodology as described below. See Note 3, *2018 Acquisitions*, for further discussion of the CNX and Hess Acquisition and the UMD Acquisition.

The key inputs used to estimate the fair value of the natural gas and oil properties acquired in the CNX and Hess Acquisition and the UMD Acquisition are as follows:

Market-based weighted average cost of capital rate	9.0%
Reserve risk factors	10% - 100%
Natural gas price	Three years NYMEX Henry Hub forward curve
Oil price	Three years NYMEX WTI forward curve
NGL price	36% - 46% of oil price
Price escalation after end of forward curve	2.0%

The initial measurement of asset retirement obligations is recorded at fair value and calculated using discounted cash flow techniques based on internal estimates, including reserve lives and plugging costs, of future retirement costs associated with the Company's natural gas and oil properties. The Company has classified the fair value of the additions to asset retirement obligations as Level 3 due to the fact that the valuation is based upon significant unobservable inputs.

8. Related Party Transactions

Management Services Agreement

In August 2015, the Company and the Member entered into a management services agreement (Ascent MSA). Under the Ascent MSA, the Member performed any and all general management, administrative and operating services requested by and at the direction of the Company. The Member invoiced the Company monthly for cash it paid for any costs expended on behalf of the Company in performance of the services. During the three and nine months ended September 30, 2017, the Company incurred expenses of approximately $14.4 million and $42.6 million for the services performed under the Ascent MSA, of which $6.2 million and $15.9 million related to direct labor or overhead and was recognized in lease operating expenses, exploration expense or natural gas and oil properties, as applicable. On January 1, 2018, the Member assigned the Ascent MSA to Ascent Resources Management Services, LLC (ARMS), a wholly-owned subsidiary of ARUH, in an effort to bring all management services under direct control of the Company (the MSA Assignment). Due to the MSA Assignment, all costs for the services performed under the Ascent MSA are consolidated by the Company, and therefore, there are no related party expenses in 2018 related to the Ascent MSA. As part of the MSA Assignment, the Member contributed all of its non-cash assets and liabilities to ARMS, resulting in an increase to equity of $3.5 million in January 2018.

UMD Agreements

UMD was indirectly, majority owned by investment funds controlled by EMG and First Reserve. In May 2017, the Company and UMD entered into a development agreement whereby an AMI was established encompassing Jefferson County, Ohio. Prior to the closing of the UMD Acquisition and within the AMI, each party had 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. Properties acquired by UMD, and not subject to a pre-existing unit operating agreement, were operated by the Company. In August 2017, the Company and UMD acquired the 2017 Acquisition Properties and entered into an earn-in agreement, where the Company could have earned an additional undivided 25% interest in the 2017 Acquisition Properties from UMD by drilling and operating a designated set of wells on the 2017 Acquisition Properties and carrying 100% of UMD's carried costs. Upon completion of the UMD Acquisition in July 2018, discussed in Note 3, *2018 Acquisitions*, the development agreement and the earn-in agreement were terminated.

Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements

The Company has entered into certain business relationships with entities in which EMG or First Reserve have control or significant influence. The gathering, processing and transportation (GP&T) expenses incurred and NGL revenues realized with the Company's related parties, excluding any reimbursement to or from working interest and royalty interest owners, where appropriate, or credits for third party volumes, are presented below for the periods indicated:

($ in thousands)	Condensed Consolidated Statements of Operations Earnings Caption	Three Months Ended September 30, 2018	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Crestwood Services, LLC[a]	NGL revenues	$ 29,627	$ —	$ 47,059	$ —
Jefferson Gas Gathering Company, LLC[b]	GP&T expenses	$ (29,017)	$ (12,000)	$ (71,822)	$ (22,200)
MarkWest Utica EMG, LLC[c]:	GP&T expenses	$ (10,104)	$ (8,700)	$ (26,662)	$ (27,500)
	NGL revenues	$ 11,483	$ 24,335	$ 48,297	$ 71,375
Ohio Gathering Company, LLC[c]	GP&T expenses	$ (11,743)	$ (9,600)	$ (30,337)	$ (27,100)
Ohio River System LLC[d]	GP&T expenses	$ (14,622)	$ (6,500)	$ (37,394)	$ (14,000)
Rover Pipeline LLC[e]	GP&T expenses	$ (61,619)	$ —	$ (143,053)	$ —
Rockies Express Pipeline LLC[f]	GP&T expenses	$ (28,067)	$ (28,100)	$ (84,186)	$ (84,000)

The receivables due from or (payables due to) the Company's related parties, excluding any reimbursement to or from working interest and royalty interest owners, where appropriate, or credits for third party volumes, are presented below for the periods indicated:

($ in thousands)	Condensed Consolidated Balance Sheets Classification	September 30, 2018	December 31, 2017
Crestwood Services, LLC[a]	Accounts receivable - natural gas, oil and NGL sales	$ 11,186	$ —
Jefferson Gas Gathering Company, LLC[b]	Accounts payable	$ (19,827)	$ (12,800)
MarkWest Utica EMG, LLC[c]:	Accounts receivable - natural gas, oil and NGL sales	$ 7,589	$ 10,400
Ohio Gathering Company, LLC[c]:	Accounts payable	$ (15,293)	$ (7,000)
Ohio River System LLC[d]	Accounts payable	$ (9,800)	$ (3,200)
Rover Pipeline LLC[e]	Accounts payable	$ (19,975)	$ (9,300)
Rockies Express Pipeline LLC[f]	Accounts payable	$ (9,353)	$ (9,400)

[a] In March 2018, the Company entered into an NGL sales agreement with Crestwood Services, LLC (Crestwood). First Reserve has significant influence over Crestwood through its indirect equity investment in the general partner of Crestwood Equity Partners, LP.

[b] 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.

[c] 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.

[d] 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. For information regarding the credit support requirements due to ORS, see Note 9, *Pipeline Commitments*.

[e] 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 commenced in June 2018. For information regarding the credit support requirements due to Rover, see Note 9, *Pipeline Commitments*.

(f) In April and October 2014, the Company entered into firm transportation agreements with Rockies Express Pipeline LLC (REX). REX is majority owned by Tallgrass Energy Partners, LP (Tallgrass). EMG has significant influence over REX through its indirect equity investments in Tallgrass. For information regarding the credit support requirements due to REX, see Note 9, *Pipeline Commitments*.

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.

9. 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 and, if necessary, with the assistance of legal counsel and 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, that have initial or remaining non-cancelable terms in excess of one year as of September 30, 2018:

($ in thousands)	Pipeline Commitments	Operating Leases	Other Purchase Obligations	Total
Remaining in 2018	$ 147,532	$ 887	$ 42	$ 148,461
2019	610,374	3,672	394	614,440
2020	641,204	3,283	156	644,643
2021	657,426	631	46	658,103
2022	661,053	—	—	661,053
Thereafter	7,489,566	—	—	7,489,566
Total	$ 10,207,155	$ 8,473	$ 638	$ 10,216,266

Pipeline Commitments

As of September 30, 2018, the Company had certain pipeline capacity commitments which will reduce the impact of possible production curtailments that may arise due to limited capacity. Working interest owners and royalty interest owners, where appropriate, will be responsible for their proportionate share of these costs. To satisfy credit support requirements for these commitments, the Company has issued letters of credit and/or surety bonds to certain transportation providers, as discussed below.

As discussed in Note 8, *Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements,* the Company entered into certain firm transportation commitments with ORS, Rover and REX. Pursuant to these commitments, the Company is obligated to provide (i) ORS with credit support ranging from $40.0 million to $75.0 million; (ii) Rover with credit support in the amount of one year of demand charges, which may reach $250.8 million; and (iii) REX with credit support ranging from nine months of fees to 27 months of fees, pursuant to specific commitments, totaling $128.6 million. As of September 30, 2018, the Company had issued $40.0 million in letters of credit to ORS, $241.3 million in letters of credit to Rover, $67.0 million in letters of credit to REX and $75.2 million in letters of credit to certain other firm transportation providers. Additionally, the Company has $61.6 million in surety bonds outstanding as collateral to satisfy its remaining firm transportation commitments with REX.

Operating Lease Commitments

The Company leases certain equipment and office space. Lease expense related to operating leases totaled $1.4 million, $0.6 million, $4.2 million and $1.3 million during the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Increases in lease expense related to operating leases are primarily due to the MSA Assignment, as discussed in Note 8, *Management Services Agreement*.

Joint Venture Commitment

In 2013, the Company entered into a joint venture participation agreement in order to acquire interests in unproved leasehold. Under the agreement, the Company was required to pay the seller's retained share of carried costs for certain wells and other development operations that occurred within an AMI as defined in the agreement. The acquisition obligation represented the difference in the purchase price of the interests in unproved leasehold and the cash paid by the Company. The agreement further stipulated that if the Company failed to repay its obligation for such carried costs by certain periods of time, then the Company would have been required to pay the seller any shortfall in cash. In February 2016, the Company executed an amendment which extended the payment terms of carried costs from four years to five years. In November 2017, the Company executed a second amendment which expanded the AMI and reduced the carry obligations by $21.8 million in lieu of a cash payment with the closing of the Company's divestiture of certain natural gas and oil properties to the seller. As of September 30, 2018 and December 31, 2017, the Company owed $18.8 million and $61.1 million, respectively, for this obligation. This obligation was discounted using an 11% discount rate, to reflect the imputation of interest, and was presented as a current liability on the condensed consolidated balance sheets. The joint venture participation agreement expired on September 30, 2018, and the Company satisfied and paid the remaining obligation in October 2018, as discussed in Note 11, *Joint Venture Commitment*.

Contingency

In November 2017, the Company acquired both producing and non-producing natural gas and oil properties located in the Utica Shale. See Note 3, *2017 Acquisitions and Divestitures*, for further discussion. This acquisition includes contingent consideration of up to $15.0 million if the average West Texas Intermediate (WTI) daily price of crude oil is greater than certain pre-defined prices in 2018, 2019 and 2020, respectively. Due to recent oil prices and projections for the remainder of 2018, the Company recognized a liability of $5.0 million as of September 30, 2018. The Company's joint venture partner is responsible for 20% of any contingent consideration payments made. This contingency will be reassessed quarterly to determine if additional accruals should be recorded in the future.

10. Other Current Liabilities

The Company's other current liabilities consisted of the following as of September 30, 2018 and December 31, 2017:

($ in thousands)	September 30, 2018	December 31, 2017
Drilling and completion accrual	$ 109,774	$ 96,944
Gathering, processing and transportation expense accrual	105,058	55,541
Other	77,814	47,615
Total Other Current Liabilities	$ 292,646	$ 200,100

11. Subsequent Events

The Company evaluated its September 30, 2018 condensed consolidated financial statements for subsequent events through November 14, 2018, the date the unaudited condensed consolidated financial statements were available to be issued, and such events are noted below.

Debt Refinancing

In October 2018, the Company issued the 2026 Notes with an aggregate principal amount of $600.0 million in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act at 99.24% of par. The 2026 Notes are due on November 1, 2026, and interest is payable at an annual rate of 7.00% on May 1 and November 1 of each year, beginning with May 1, 2019. The Company used approximately $579.0 million of the net proceeds from the issuance of the 2026 Notes to fund the Redemption of $525.0 million aggregate principal amount of the 2022 Notes at a redemption price equal to 110% of the principal thereof, plus $1.5 million of accrued and unpaid interest to, but excluding, the date of the Redemption. The Company used the remaining net proceeds to repay borrowings under the Credit Facility.

Joint Venture Commitment

In October 2018, the Company satisfied and paid the remaining obligation of $18.8 million under a joint venture participation agreement. See Note 9, *Joint Venture Commitment*, for further discussion of the joint venture participation agreement.

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 audited consolidated financial statements, the related notes and "Management's Discussion and Analysis of Financial Condition and Results of Operations" for the year ended December 31, 2017, in addition to the unaudited condensed consolidated financial statements and related notes, included within this quarterly report. 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.

Restatement of Financial Information

As described further in Note 2 to the accompanying unaudited condensed consolidated financial statements included in this report, we have restated our unaudited condensed consolidated financial statements and related footnote disclosures as of September 30, 2018 and for the three and nine months ended September 30, 2018. The following discussion and analysis of the Company's financial condition and results of operations incorporates the restated amounts. For this reason, the data set forth in this Management's Discussion and Analysis of Financial Condition and Results of Operations may not be comparable to the discussion and data in our previously issued report (Original Report) as of September 30, 2018 and for the three and nine months ended September 30, 2018.

Overview

We are an independent exploration and production company engaged in the acquisition, exploration and development of natural gas and oil properties in the Utica Shale of the Appalachian Basin in Ohio. We are a wholly-owned subsidiary of Ascent Resources Operating, LLC (Member) and an indirect wholly-owned subsidiary of Ascent Resources, LLC (Parent). We were formed in 2013 by our private equity sponsors, primarily The Energy & Minerals Group 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 Shale, one of the premier North American natural gas and oil shale plays. Our largely contiguous footprint of approximately 311,000 net leasehold acres lies within the core of the southern Utica Shale 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 also own royalty interests on approximately 71,000 fee mineral acres that provide enhanced value without additional capital or operating expenses. We have strategically assembled our position in the southern Utica Shale 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 Shale.

We are continuously focused on enhancing our drilling and completion techniques, minimizing costs and maximizing the ultimate recovery of natural gas, oil and natural gas liquids (NGL) 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.

Segment and Geographical Information

We have one reportable operating segment in the United States and a single company-wide management team that administers all properties as a whole rather than by distinct operating segments. We measure financial performance as a single enterprise and not on a geographical basis.

2018 Highlights

- In October, we issued $600.0 million in aggregate principal amount of 7.00% senior unsecured notes (2026 Notes) due November 2026. The net proceeds from the 2026 Notes were used to redeem $525.0 million aggregate principal amount of our 2022 Notes (the Redemption) at a redemption price equal to 110% of the principal thereof, plus accrued and unpaid interest to, but excluding, the date of the Redemption. The remaining net proceeds were used to repay borrowings under our Credit Facility (as defined below).

- In June, July and August, we received cash proceeds of approximately $575.4 million from our Parent's issuance of common equity to fund the CNX and Hess Acquisition and the UMD Acquisition (both as defined below). Additionally, our Parent issued approximately $463.8 million, in aggregate, of its common equity directly to the sellers in the UMD Acquisition and the Salt Fork Acquisition (as defined below) bringing total equity contributions to approximately $1.04 billion to fund these acquisitions.

- In August, we acquired producing and non-producing natural gas and oil properties in the Utica Shale, which included approximately 24,000 net leasehold acres, 46,000 acres of unencumbered fee minerals and royalties on 8,400 acres of fee minerals, from CNX Resources Corporation and Hess Corporation (together, the CNX and Hess Acquisition) for consideration of approximately $765.7 million, subject to post-closing adjustments. Funding for the CNX and Hess Acquisition consisted of borrowings from our Credit Facility (as defined below) and cash proceeds contributed to us from a common equity offering by our Parent.

- In August, we acquired primarily non-producing natural gas and oil properties in the Utica Shale, which consisted of approximately 23,000 net unproved leasehold acres and approximately 1,000 acres of unencumbered fee minerals, from Salt Fork Resources Employer, LLC (Salt Fork) for $223.0 million (the Salt Fork Acquisition), subject to customary closing adjustments. The Salt Fork Acquisition was funded entirely with common equity issued to the seller directly from our Parent.

- In March, June and August, we executed amendments to our $2.5 billion revolving credit facility (Credit Facility), which, in aggregate, increased the borrowing base from $925.0 million to a fully committed $1.85 billion, increased the sublimit for letters of credit from $647.5 million to $750.0 million, decreased the applicable interest margins by 1.00% and increased the aggregate maximum credit amount from $1.5 billion to $2.5 billion. The amendment to the Credit Facility in August set the next redetermination for November 2018.

- In July, we acquired producing and non-producing natural gas and oil assets in the Utica Shale, which included approximately 5,400 net leasehold acres and 14,200 acres of unencumbered fee minerals, from Utica Minerals Development, LLC (UMD) for consideration of approximately $501.4 million (the UMD Acquisition), including customary closing adjustments and approximately $238.6 million of common equity issued from our Parent. The cash portion of the purchase price was funded using proceeds contributed to us from a common equity offering by our Parent.

- During the three months ended September 30, 2018, we spud 31 wells, hydraulically fractured 29 wells and turned-in-line 30 new wells. During the nine months ended September 30, 2018, we spud 92 wells, hydraulically fractured 91 wells and turned-in-line 82 new wells.

Non-GAAP Financial Measures

In evaluating our current and future financial results, we focus on production and revenue growth, lease operating expenses and general and administrative expenses. In addition to these metrics, we use adjusted net income, EBITDAX and adjusted EBITDAX (non-GAAP measures) to evaluate our financial results. We define adjusted net income as net income (loss) before unproved leasehold impairment; losses or gains on purchases or exchanges of debt; changes in fair value of commodity derivatives; changes in fair value of embedded derivative; acquisition expenses; and incentive units expense (income). We define EBITDAX as net income (loss) before exploration expenses; depreciation, depletion and amortization (DD&A); interest expense, net; and acquisition obligation accretion. We define adjusted EBITDAX as EBITDAX before changes in fair value of embedded derivative; changes in fair value of commodity derivatives; acquisition expenses; incentive units expense (income); and other unusual items. These non-GAAP measures are not measures of net income (loss) as determined by United States generally accepted accounting principles (US GAAP).

Non-GAAP measures, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and are not measures of performance calculated in accordance with US GAAP. Non-GAAP measures should not be considered in isolation or as substitutes for operating income, net income or loss, cash flows provided by operating, investing and financing activities or other income or cash flow statement data prepared in accordance with US GAAP. Non-GAAP measures provide no information regarding a company’s capital structure, borrowings, interest costs, capital expenditures and working capital movement. Non-GAAP measures do not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, taxes, exploration expenses and other commitments and obligations. However, our management team believes our non-GAAP measures are useful to an investor in evaluating our financial performance because these measures:

- Are widely used by investors in the natural gas and oil industry to measure a company’s operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

- Are more comparable to estimates used by analysts;

- Help investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure;

- Excludes one-time items, non-cash items or items whose timing cannot be reasonably estimated; and

- Are used by our management team for various purposes, including as a measure of operating performance, in presentations to our Board of Managers and as a basis for strategic planning and forecasting.

There are significant limitations to using non-GAAP measures as measures of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating non-GAAP measures reported by different companies.

Reconciliations of Non-GAAP Financial Measures

The following table represents a reconciliation of net loss, the most directly comparable US GAAP financial measure, to adjusted net income:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
($ in thousands)	(Restated)		(Restated)	
Net Loss	$ (5,079)	$ (25,904)	$ (128,635)	$ (116,944)
Adjustments to reconcile net loss to adjusted net income:				
Exploration expenses - unproved leasehold impairment	38,291	22,633	113,816	136,738
Losses on purchases or exchanges of debt	—	—	—	114,052
Change in fair value of commodity derivatives	42,460	27,304	132,892	(96,042)
Change in fair value of embedded derivative	(8,503)	633	(14,161)	18,603
Acquisition expenses	9,130	—	9,130	—
Incentive units expense (income)	182	34	(1,425)	(80)
Adjusted Net Income (Non-GAAP)	$ 76,481	$ 24,700	$ 111,617	$ 56,327

The following table represents a reconciliation of net loss, the most directly comparable US GAAP financial measure, to EBITDAX and then to adjusted EBITDAX:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
($ in thousands)	(Restated)		(Restated)	
Net Loss	$ (5,079)	$ (25,904)	$ (128,635)	$ (116,944)
Adjustments to reconcile net loss to EBITDAX:				
Exploration expenses	39,030	22,936	115,937	137,868
Natural gas and oil depreciation, depletion and amortization	135,853	80,034	342,446	208,405
Depreciation and amortization of other assets	997	487	2,882	1,435
Interest expense, net	25,908	23,668	65,465	46,517
Acquisition obligation accretion expense	137	967	1,030	3,531
EBITDAX (Non-GAAP)	196,846	102,188	399,125	280,812
Adjustments to reconcile EBITDAX to Adjusted EBITDAX:				
Change in fair value of embedded derivative	(8,503)	633	(14,161)	18,603
Loss on purchases or exchanges of debt	—	—	—	114,052
Change in fair value of commodity derivatives	42,460	27,304	132,892	(96,042)
Acquisition expenses	9,130	—	9,130	—
Incentive units expense (income)	182	34	(1,425)	(80)
Adjusted EBITDAX (Non-GAAP)	$ 240,115	$ 130,159	$ 525,561	$ 317,345

Adjusted net income was $76.5 million and $24.7 million for the three months ended September 30, 2018 and 2017, respectively, an increase of 210%, and adjusted EBITDAX was $240.1 million and $130.2 million for the three months ended September 30, 2018 and 2017, respectively, an increase of 84%. Adjusted net income was $111.6 million and $56.3 million for the nine months ended September 30, 2018 and 2017, respectively, an increase of 98%, and adjusted EBITDAX was $525.6 million and $317.3 million for the nine months ended September 30, 2018 and 2017, respectively, an increase of 66%. The increases in these non-GAAP measures for the three and nine months ended September 30, 2018 compared to the same periods in 2017 are primarily due to increases in the volumes of natural gas produced, which were partially offset by increases in gathering, processing and transportation expenses.

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, proceeds from the issuance of debt, draws on our credit facility, cash flow from operations and asset sales. Equity contributions from our Parent, draws on our credit facility, cash on hand, cash flow from operations and other capital market transactions will be our primary sources of liquidity in the future.

As of September 30, 2018, we had a cash balance of $10.9 million. In August 2018, the borrowing base under the Credit Facility was redetermined and adjusted to a fully committed amount of $1.85 billion, and the aggregate maximum credit amount was increased to $2.5 billion in June 2018. As of November 14, 2018, we had borrowings of $973.0 million and $404.3 million of letters of credit outstanding. Based on our current cash balance, credit facility availability and expected operating cash flows, we anticipate being able to satisfy all of our financial obligations and commitments for the next twelve months.

We anticipate an increase in our revenues during the remainder of 2018 compared to 2017 due to expected increased production related to our drilling program and the closing of the acquisitions discussed in Note 3, *2018 Acquisitions*. 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 from operations and the 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 liquidity is subject to risks and uncertainties that exist in our industry, some of which we may not be able to anticipate or control.

Sources of Funds

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

	Nine Months Ended September 30,	
($ in thousands)	2018	2017
Cash provided by operating activities	$ 507,291	$ 299,877
Proceeds from credit facility borrowings	1,035,000	—
Contributions from Member	568,201	132,000
Proceeds from divestitures of natural gas and oil properties	6,564	—
Proceeds from sales of other property and equipment	175	13
Proceeds from issuance of long-term debt, net	—	1,466,250
Reductions in deposits on pipeline capacity	—	147,715
Total Sources of Cash and Cash Equivalents	$ 2,117,231	$ 2,045,855

Net cash flow provided by operating activities was approximately $507.3 million and $299.9 million for the nine months ended September 30, 2018 and 2017, respectively. The increase in operating cash flow was primarily the result of increased natural gas production.

We received $568.2 million and $132.0 million in net cash contributions from equity capital raised by our Parent during the nine months ended September 30, 2018 and 2017, respectively. We borrowed $1.035 billion from our Credit Facility during the nine months ended September 30, 2018 and repaid $285.0 million during the same period. Additionally, we paid $8.9 million of debt issuance costs related to redeterminations of our Credit Facility. We also received $6.6 million during the nine months ended September 30, 2018 for costs incurred related to the 2017 Utica Divestiture, as discussed in Note 3, *2017 Acquisitions and Divestitures*, of the notes to our condensed consolidated financial statements included in this report.

During the nine months ended September 30, 2017 we received a net $1.466 billion in cash from the issuance of the 2022 Notes. The proceeds were used to repay the $1.290 billion of outstanding principal plus any accrued and unpaid interest and prepayment penalty of the Second Lien Term Loans. Additionally, we paid $14.4 million of debt issuance costs related to the 2022 Notes and the Credit Facility. The remaining proceeds were used for general corporate purposes. See Note 5 of the notes to our condensed consolidated financial statements included in this report for further information regarding our long-term debt.

Uses of Funds

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

($ in thousands)	Nine Months Ended September 30, 2018	Nine Months Ended September 30, 2017
Natural Gas and Oil Expenditures:		
Drilling and completion costs	$ (635,434)	$ (434,087)
Acquisitions of natural gas and oil properties	(1,226,063)	(202,073)
Interest capitalized on unproved leasehold	(68,758)	(47,573)
Deposit on natural gas and oil property acquisition	—	(6,200)
Total Natural Gas and Oil Expenditures	(1,930,255)	(689,933)
Other Uses of Cash and Cash Equivalents:		
Repayment of credit facility borrowings	(285,000)	—
Cash paid for debt issuance costs	(8,899)	(14,366)
Additions to other property and equipment	(1,424)	(140)
Repayment of debt	—	(1,290,264)
Cash paid for debt prepayment costs	—	(70,999)
Total Other	(295,323)	(1,375,769)
Total Uses of Cash and Cash Equivalents	$ (2,225,578)	$ (2,065,702)

Our drilling and completion costs were $635.4 million and $434.1 million for the nine months ended September 30, 2018 and 2017, respectively. The increase is primarily the result of increased drilling and completion activity. During the nine months ended September 30, 2018, our average operated rig count was seven rigs, compared to an average operated rig count of five rigs during the same period in 2017, and we spud 92 wells, hydraulically fractured 91 wells and turned-in-line 82 new wells during the nine months ended September 30, 2018, compared to the same period in 2017 during which we spud 62 wells, hydraulically fractured 58 wells and turned-in-line 72 new wells.

We spent cash of $765.7 million to fund the CNX and Hess Acquisition and $262.8 million to fund the UMD Acquisition, which is included in our natural gas and oil property acquisition costs during the nine months ended September 30, 2018. Funding for the CNX and Hess Acquisition consisted of borrowings under our Credit Facility and cash proceeds contributed to us from a common equity offering by our Parent. The cash consideration for the UMD Acquisition was funded using proceeds contributed to us from a common equity offering by our Parent, and $238.6 million of common equity was issued directly from our Parent to the seller. For further discussion of these acquisitions, see Note 3, *2018 Acquisitions*, of the notes to our condensed consolidated financial statements included in this report. We spent additional cash of $197.5 million and $202.1 million during the nine months ended September 30, 2018 and 2017, respectively, primarily related to the acquisition of leases, which arose during the ordinary course of business.

Certain Indebtedness

Credit Facility

The amount available to be borrowed under the Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about April 1 and October 1 of each year based on the estimated value and future net cash flows of our proved natural gas, oil and NGL reserves and our commodity derivative positions. In 2017, the borrowing base increased from the initial $650.0 million to a fully committed $925.0 million and the sublimit for letters of credit increased from $450.0 million to $647.5 million. We also executed amendments to the Credit Facility in March, June and August of 2018, which, in aggregate, increased the borrowing base from $925.0 million to a fully committed $1.85 billion, increased the sublimit for letters of credit from $647.5 million to $750.0 million, decreased the applicable interest margins by 1.00% and increased the aggregate maximum credit amount from $1.5 billion to $2.5 billion. The amendment to the Credit Facility in August 2018 set the next redetermination for November 2018. As of September 30, 2018, we had borrowings of $750.0 million and $423.5 million of letters of credit outstanding under the Credit Facility. As of November 14, 2018, we had borrowings of $973.0 million and $404.3 million of 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 0.50% or (iii) the rate for 1-month Eurodollar loans, plus an applicable margin ranging from 0.75% to 1.75% per annum. Eurodollar loans bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 1.75% to 2.75% per annum. Due to the weighted average 1-month LIBOR being 2.18% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.43% per annum as of September 30, 2018. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. The 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, 2018, we were in compliance with all applicable financial covenants under the Credit Facility. See Note 5, *Credit Facility*, of the notes to our condensed consolidated financial statements for further discussion of the terms of the Credit Facility.

Senior Notes

In October 2018, we issued the 2026 Notes with an aggregate principal amount of $600.0 million in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. We used proceeds from the issuance of the 2026 Notes to fund the Redemption through which we exercised our right to redeem 35%, or $525.0 million, of the aggregate principal amount of the 2022 Notes at a redemption price equal to 110% of the principal thereof, plus accrued and unpaid interest to, but excluding the date of the Redemption. We used the remaining net proceeds to repay borrowings under the Credit Facility. See Note 11, *Debt Refinancing*, of the notes to our condensed consolidated financial statements for further discussion.

The 2022 Notes are due on April 1, 2022, and interest is payable at an annual rate of 10.00% on April 1 and October 1 of each year, which commenced on October 1, 2017. 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 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.

The 2022 Notes are our senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured 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, 2018, we were in compliance with all applicable covenants of the 2022 Notes indenture. See Note 5, *Senior Notes*, of the notes to our condensed consolidated financial statements for further discussion of the terms of the 2022 Notes.

Convertible Notes

As of September 30, 2018, we had $72.9 million in aggregate principal, including accrued and unpaid interest, outstanding under the convertible notes due 2021 (Convertible Notes). The Convertible Notes are subordinate to the 2022 Notes, which rank senior in right of payment.

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 3.50%. On March 1, 2016, the interest rate began escalating by 0.50% on each interest payment date, subject to a maximum interest rate of 6.50% per annum, which was achieved on September 1, 2018, because 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. 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 and at the option of the noteholders, the Convertible Notes may be converted into common shares of the initial public offering issuer at a premium to the principal of the notes.

The Convertible Notes also provide for cash redemption upon a change of control event at the option of the holders at a premium of 153.8% of the principal amount of the Convertible Notes. The Convertible Notes are not redeemable by the holders 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% of the principal of the Convertible Notes to be redeemed, plus accrued and unpaid interest, if any. See Note 5, *Convertible Notes*, of the notes to our condensed consolidated financial statements for further discussion of the terms of the Convertible Notes.

In March 2017, we retired $11.1 million of outstanding principal and accrued and unpaid interest associated with Convertible Notes contributed to us by our 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.

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 commitments, drilling rig commitments and various other commitments in the ordinary course of business. See Note 9 of the notes to our condensed consolidated financial statements for further details of our commitments.

New Accounting Pronouncements

See Note 1, *Adopted and Recently Issued Accounting Pronouncements,* of the notes to our condensed consolidated financial statements for a description of recent accounting pronouncements.

Results of Operations

The following table sets forth certain information regarding our net production volumes, natural gas, oil and NGL sales, average sales prices received, and certain of our operating expenses for the periods indicated. Average sales prices listed in the table below are based on thousand cubic feet (mcf) of natural gas and barrels (bbls) of oil and NGL.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2018	2017	2018	2017
Net Production Volumes:				
Natural gas (mmcf)	126,283	66,495	308,932	155,987
Oil (mbbls)	774	604	1,549	2,006
NGL (mbbls)	1,035	779	2,290	2,519
Natural Gas Equivalent (mmcfe)	137,145	74,793	331,978	183,137
Natural Gas, Oil, and NGL Sales ($ in thousands):				
Natural gas	$ 364,580	$ 177,646	$ 884,857	$ 457,797
Oil	49,064	25,609	95,997	87,409
NGL	33,634	17,047	68,077	53,474
Settlements of commodity derivatives	(540)	10,056	21,522	9,143
Change in fair value of commodity derivatives	(42,460)	(27,304)	(132,892)	96,042
Total	$ 404,278	$ 203,054	$ 937,561	$ 703,865
Average Daily Net Production Volumes:				
Natural gas (mmcf/d)	1,373	723	1,132	571
Oil (mbbls/d)	8	7	6	7
NGL (mbbls/d)	11	9	8	9
Natural Gas Equivalent (mmcfe/d)	1,491	813	1,216	671
Average Sales Prices:				
Natural gas ($/mcf)	$ 2.89	$ 2.67	$ 2.86	$ 2.93
Oil ($/bbl)	$ 63.36	$ 42.40	$ 61.97	$ 43.58
NGL ($/bbl)	$ 32.47	$ 21.89	$ 29.73	$ 21.22
Natural Gas Equivalent ($/mcfe)	$ 3.26	$ 2.95	$ 3.16	$ 3.27
Settlements of commodity derivatives ($/mcfe)	—	0.13	0.06	0.05
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.26	$ 3.08	$ 3.22	$ 3.32
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.08	$ 0.14	$ 0.10	$ 0.13
Gathering, processing and transportation expenses	$ 1.29	$ 1.04	$ 1.38	$ 1.24
Production and ad valorem taxes	$ 0.05	$ 0.05	$ 0.05	$ 0.05
General and administrative expenses, including related party (Restated)	$ 0.08	$ 0.13	$ 0.11	$ 0.17
Natural gas and oil depreciation, depletion and amortization	$ 0.99	$ 1.07	$ 1.03	$ 1.14
Depreciation and amortization of other assets	$ 0.01	$ 0.01	$ 0.01	$ 0.01

General. For the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, we had net losses of $5.1 million, $25.9 million, $128.6 million and $116.9 million, respectively, on total revenues of $404.3 million, $203.1 million, $937.6 million and $703.9 million, respectively. The net losses in 2018 were primarily driven by unrealized commodity derivative losses, increased interest expense associated with our long-term debt, and increased gathering, processing and transportation expenses. However, these were largely offset by increased natural gas, oil and NGL sales and a decrease in lease operating expenses per mcfe from 2018 to 2017. The net loss during the three months ended September 30, 2017 was primarily driven by unrealized commodity derivative losses and interest expense associated with our long-term debt. The net loss during the nine months ended September 30, 2017 was primarily driven by losses on our debt repurchase transactions in April 2017, interest expense associated with our long-term debt and higher rates of lease operating expenses, which were largely offset by unrealized commodity derivative gains.

Natural Gas Sales. During the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, natural gas sales (excluding the effects of derivatives) were $364.6 million, $177.6 million, $884.9 million and $457.8 million, respectively. During the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, we sold 126.3 bcf, 66.5bcf, 308.9 bcf and 156.0 bcf of natural gas, respectively, at weighted average prices of $2.89, $2.67, $2.86 and $2.93 per mcf, respectively (excluding the effects of derivatives). The $187.0 million increase in natural gas sales for the three months ended September 30, 2018 compared to the three months ended September 30, 2017 was driven by a 90% increase in natural gas production and an 8% increase in the average sales price received for natural gas. The $427.1 million increase in natural gas sales for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 was driven by a 98% increase in natural gas production, which was partially offset by a 2% decrease in the average sales price received for natural gas.

Gains and losses from our natural gas derivatives resulted in a $16.8 million increase and a $10.7 million decrease in natural gas revenues for the three months ended September 30, 2018 and 2017, respectively, and a $0.9 million increase and a $90.2 million increase in natural gas revenues for the nine months ended September 30, 2018 and 2017, respectively. Natural gas hedging settlements were $7.1 million, $7.3 million, $37.9 million and $2.2 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our production levels for the three and nine months ended September 30, 2018 remained constant and without considering the effect of derivatives, an increase or decrease of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in sales and cash flows of approximately $12.6 million and $30.9 million for the three and nine months ended September 30, 2018, respectively.

Oil Sales. During the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, oil sales (excluding the effects of derivatives) were $49.1 million, $25.6 million, $96.0 million and $87.4 million, respectively. During the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, we sold 774 mbbls, 604 mbbls, 1,549 mbbls and 2,006 mbbls, respectively, at weighted average prices of $63.36, $42.40, $61.97 and $43.58 per bbl, respectively, (excluding the effects of derivatives). The $23.5 million increase in oil sales for the three months ended September 30, 2018 compared to the three months ended September 30, 2017 was driven by a 28% increase in oil production and a 49% increase in the average sales price received for oil. The $8.6 million increase in oil sales for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 was driven by a 42% increase in the average sales price received for oil, which was partially offset by a 23% decrease in oil production.

Gains and losses from our oil derivatives resulted in a $47.6 million decrease and a $6.5 million decrease in oil revenues for the three months ended September 30, 2018 and 2017, respectively, and a $100.1 million decrease and a $15.0 million increase in oil revenues for the nine months ended September 30, 2018 and 2017, respectively. Oil hedging settlements were $(7.4) million, $2.8 million, $(16.2) million and $6.9 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively.

A change in oil prices has a direct impact on our sales and cash flows. Assuming our production levels for the three and nine months ended September 30, 2018 remained constant and without considering the effects of derivatives, an increase or decrease of $1.00 per barrel of oil sold would have resulted in an increase or decrease in sales and cash flows of approximately $0.8 million and $1.5 million for the three and nine months ended September 30, 2018, respectively.

NGL Sales. During the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, NGL sales were $33.6 million, $17.0 million, $68.1 million and $53.5 million, respectively. During the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, we sold 1,035 mbbls, 779 mbbls, 2,290 mbbls and 2,519 mbbls, respectively, of NGL at weighted average prices of $32.47, $21.89, $29.73 and $21.22 per bbl, respectively. The $16.6 million increase in NGL sales for the three months ended September 30, 2018 compared to the three months ended September 30, 2017 was driven by a 48% increase in the average sales price received for NGL and a 33% increase in NGL production. The $14.6 million increase in NGL sales for the nine months ended September 30, 2018 compared to the nine months ended September 30, 2017 was driven by a 40% increase in the average sales price received for NGL, which was partially offset by a 9% decrease in NGL production.

Gains and losses from our NGL derivatives resulted in a $12.2 million decrease in NGL revenues for the both three and nine months ended September 30, 2018. NGL hedging settlements were $(0.3) million for both the three and nine months ended September 30, 2018.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our production levels for the three and nine months ended September 30, 2018 remained constant, an increase or decrease of $1.00 per barrel of NGL sold would have resulted in an increase or decrease in sales and cash flows of approximately $1.0 million and $2.3 million for the three and nine months ended September 30, 2018, respectively.

Lease Operating Expenses. Lease operating expenses were $11.4 million, $10.2 million, $34.4 million and $24.7 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. On a per unit basis, lease operating expenses were $0.08, $0.14, $0.10 and $0.13 per mcfe during the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. The per unit decreases from 2017 to 2018 were primarily the result of increased levels of production and operating efficiencies.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $176.7 million, $77.7 million, $456.6 million and $227.1 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. On a unit-of-production basis, gathering, processing and transportation expenses were $1.29, $1.04, $1.38 and $1.24 per mcfe during the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. The per unit increases from 2017 to 2018 were due to increases in contracted in-service firm transportation capacity in excess of increases in production volumes.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $7.5 million, $3.5 million, $15.7 million and $9.7 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Production taxes have increased as production volumes have increased and were $4.1 million, $2.3 million, $10.0 million and $5.4 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Production taxes are calculated using volume-based formulas that produce higher absolute costs as production increases. On a unit-of-production basis, production taxes remained consistent and were $0.03 per mcfe during the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Ad valorem taxes were $3.4 million, $1.2 million, $5.7 million and $4.3 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Ad valorem taxes are assessed annually based on wells producing at the end of each year. The amount of tax is based on an appraised value of each well including various factors such as historical production at a well level, state decline curves and prices set by the state.

Exploration Expenses. Exploration expenses were $39.0 million, $22.9 million, $115.9 million and $137.9 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. We impaired $38.3 million, $22.6 million, $113.8 million and $136.7 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively, of unproved natural gas and oil properties for which the leases are expected to expire. As we continue to review our acreage position and high grade our drilling inventory focusing on our core type curve areas, additional leasehold impairments and abandonments may be recorded.

General and Administrative Expenses, Including Related Party. General and administrative expenses, including related party expenses, were $11.7 million, $9.4 million, $37.1 million and $30.4 million for the three months ended September 30, 2018 as restated and 2017 and the nine months ended September 30, 2018 as restated and 2017, respectively. On a unit-of-production basis, general and administrative expenses, including related party expenses, were $0.08, $0.13, $0.11 and $0.17 per mcfe during the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Total general and administrative expenses, including related party, have increased in 2018 primarily due to an 11% increase in our employee count and related costs from September 30, 2017 to September 30, 2018. The absolute increases in general and administrative expenses, including related party, were offset by production volume increases over 80% for the three and nine months ended September 30, 2018 compared to the same periods in 2017, creating the decreases on a per unit basis.

Acquisition Expenses. Acquisition expenses were $9.1 million for both the three and nine months ended September 30, 2018, respectively. Acquisition expenses were incurred in connection with the closing of the CNX and Hess Acquisition and the UMD Acquisition, as discussed in Note 3, *2018 Acquisitions*, of the notes to our condensed consolidated financial statements included in this report. The incurred acquisition expenses were primarily related to legal services, due diligence expenses and filing fees, and, due to these acquisitions being accounted for as business combinations, they were not capitalized.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $135.9 million, $80.0 million, $342.4 million and $208.4 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs and the related underlying reserves, was $0.99, $1.07, $1.03 and $1.14 per mcfe during the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. The per unit decreases were the result of a 78% increase in total proved reserves from September 30, 2017 to September 30, 2018, which was only partially offset by a 57% increase in net capitalized costs during the same period. Our proved reserves increased organically through the drillbit and through the acquisitions discussed in Note 3, *2018 Acquisitions* of the notes to our condensed consolidated financial statements included in this report.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $1.0 million, $0.5 million, $2.9 million and $1.4 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. 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 a field office and other corporate assets.

Interest Expense. Interest expense was $25.9 million, $23.7 million, $65.5 million and $46.5 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively, detailed as follows along with weighted average borrowings:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ in thousands)	2018	2017	2018	2017
Interest expense on 2022 Notes	$ 37,500	$ 37,500	$ 112,512	$ 72,917
Interest expense on Credit Facilities	11,366	4,947	24,469	9,479
Interest expense on Convertible Notes	1,097	892	3,141	2,606
Interest expense on Second Lien Term Loans	—	—	—	37,502
Interest expense on pipeline commitments	300	882	906	3,000
Amortization of debt discount and issuance costs	6,095	4,534	16,206	17,990
Capitalized interest	(30,450)	(25,087)	(91,769)	(96,977)
Total Interest Expense, net	$ 25,908	$ 23,668	$ 65,465	$ 46,517
Weighted Average Senior Notes borrowings	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 978,022
Weighted Average Credit Facility borrowings	$ 508,424	$ —	$ 236,758	$ —
Weighted Average Convertible Notes borrowings	$ 71,120	$ 67,419	$ 70,256	$ 69,672
Weighted Average Second Lien Term Loans borrowings	$ —	$ —	$ —	$ 448,993

The increase in interest expense for the three and nine months ended September 30, 2018 compared to the same periods in 2017 was primarily due to an increase in our weighted average borrowings as a result of the issuance of the 2022 Notes in April 2017 and our Credit Facility borrowings in 2018. The increase during the nine months ended September 30, 2018 was partially offset by the retirement of the Second Lien Term Loans in April 2017.

Acquisition Obligation Accretion Expense. Acquisition obligation accretion expense was $0.1 million, $1.0 million, $1.0 million and $3.5 million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. Pursuant to a joint venture participation agreement, this obligation relates to the carried interest from an asset acquisition that requires us to pay the seller's retained share of development costs for certain wells and other development operations that occur within an AMI as defined in the agreement. This obligation has been discounted using an 11% discount rate for the three and nine months ended September 30, 2018 and 2017, to reflect the imputation of interest. See Note 9, *Joint Venture Commitment*, of the notes to our condensed consolidated financial statements for more details of this commitment.

Change in Fair Value of Embedded Derivative. The change in fair value of the embedded derivative in the Convertible Notes resulted in gains or (losses) of $8.5 million, $(0.6) million, $14.2 million and $(18.6) million for the three months ended September 30, 2018 and 2017 and the nine months ended September 30, 2018 and 2017, respectively. In general, changes in the estimated price of the Convertible Notes, the par value and accrued interest outstanding, the probability and timing of early exit, expected volatility, remaining time to maturity, the credit spread between the notes and the risk-free rate and potential Qualified PO valuations in excess of a certain threshold impact the value of the embedded derivative liability.

Losses on Purchases or Exchanges of Debt. We recognized losses 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 a prior credit facility in April 2017.

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 prices we receive for our natural gas, oil and NGL production. Approximately 89% of our September 30, 2018 proved reserves were natural gas; therefore, changes in realized natural gas pricing will affect us more than changes in realized oil or NGL pricing. 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 our natural gas, oil and NGL production will depend on many factors outside of our control, including the supply of, and demand for, natural gas, oil and NGL, the level of economic activity in the United States and globally, the performance of specific industries and the volatility of natural gas, oil and NGL prices at various delivery points. 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 that we expect to produce. During the nine months ended September 30, 2018 and 2017, the average daily Henry Hub spot market price of natural gas was $2.91 per mmbtu and $2.99 per mmbtu, respectively, and the average daily West Texas Intermediate oil price was $66.79 per bbl and $49.36 per bbl, respectively.

To mitigate our exposure to adverse commodity price changes, we utilize 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, oil or NGL 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. From time to time, we may sell future call options, the premiums from which are used to obtain higher strike prices on swap and collar contracts. 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 are periodically used at the following basis points to fix the differential between product prices at one market location versus another: Chicago (Citygate), Dawn (Ontario), MichCon, Rex Zone 3, TCO and Tetco M-2.

As of September 30, 2018, we had a net liability derivative position of $32.1 million. The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of September 30, 2018 and the contracted weighted average natural gas prices:

		Weighted Average Prices ($/mmbtu)		
	Average Volume (mmbtu/d)	Swap Fixed Price	Sold Call Strike Price	Purchased Put Strike Price
Natural gas:				
Swaps:				
Remaining in 2018	1,218,000	$ 3.00		
2019	1,801,000	$ 2.86		
2020	1,340,000	$ 2.74		
2021	172,500	$ 2.74		
Collars:				
Remaining in 2018	195,000		$ 3.30	$ 2.96
2019	15,000		$ 3.40	$ 2.75
2020	140,000		$ 3.09	$ 2.59
2021	10,000		$ 2.91	$ 2.50
Call options:				
Remaining in 2018	50,000		$ 3.25	
2019	70,500		$ 3.00	
2020	250,000		$ 3.00	
2021	335,000		$ 3.02	
2022	102,500		$ 3.00	
Basis swaps:				
Remaining in 2018	224,500	$ (0.21)		
2019	249,500	$ (0.28)		
2020	70,000	$ (0.54)		

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of September 30, 2018 and the contracted weighted average oil prices:

		Weighted Average Prices ($/bbl)	
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price
Oil:			
Swaps:			
Remaining in 2018	5,600	$ 55.18	
2019	7,750	$ 56.92	
2020	7,500	$ 57.20	
2021	1,000	$ 60.06	
Call options:			
Remaining in 2018	1,000		$ 70.00
2019	2,000		$ 70.00
2020	4,750		$ 70.00
2021	3,500		$ 70.00

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of September 30, 2018 and the contracted weighted average NGL prices:

		Weighted Average Prices ($/bbl)	
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price
NGL:			
Swaps - Propane:			
Remaining in 2018	2,000	$ 38.69	
2019	3,000	$ 38.33	
2020	1,000	$ 35.07	
Call options - Propane:			
2019	1,600		$ 33.60
2020	3,150		$ 33.60
Swaps - Ethane:			
2019	1,000	$ 17.01	

As of September 30, 2018, a $0.10 per mmbtu increase or decrease in natural gas prices would have decreased or increased the fair value of our natural gas derivatives by approximately $124.3 million, respectively. As of September 30, 2018, a $1.00 per bbl increase or decrease in oil prices would have decreased or increased the fair value of our oil derivatives by approximately $8.3 million, respectively. As of September 30, 2018, a $1.00 per bbl increase or decrease in NGL prices would have decreased or increased the fair value of our NGL derivatives by approximately $3.1 million, respectively. However, any realized derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual revenue received from the sale of our production covered by the derivative instrument.

Counterparty Credit Risk

Our derivative instruments expose us to counterparty credit risk. Credit risk is the risk of loss from counterparties not performing under the terms of the derivative instrument. Adverse moves within the financial or commodities markets could negatively impact our counterparties' ability to fulfill obligations to us. To minimize such risk, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. Also, we only enter into derivative contracts with counterparties that are creditworthy. The creditworthiness of our counterparties is subject to periodic review.

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,	
	2018	2017	2018	2017
Tenaska Marketing Ventures	23%	19%	23%	25%
Sequent Energy Management, L.P.	14%	30%	17%	25%

If our largest customers stopped purchasing natural gas, oil or NGL 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 any single purchaser would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and numerous purchasers in our operating region.

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

As of September 30, 2018, the Convertible Notes bore interest at a rate of 6.50%, and the 2022 Notes bore interest at a fixed rate of 10.00%. The 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. Borrowings under the Credit Facility bear interest at a variable tiered rate based on facility usage plus the 1-month LIBOR, and the interest rate, as of September 30, 2018, was 4.43%. The variable component of our interest exposes us to interest rate risk. A 1.00% increase in the LIBOR for the three and nine months ended September 30, 2018 would have resulted in an estimated $2.3 million and $4.9 million, respectively, increase in interest expense on borrowings under the Credit Facility. We had no outstanding interest rate derivatives at September 30, 2018.

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 during 2017 or the nine months ended September 30, 2018. 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 and drilling activity increase.