MANAGEMENT'S DISCUSSION AND ANALYSIS AND
CONSOLIDATED FINANCIAL STATEMENTS

Ascent Resources Utica Holdings, LLC

As of December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016.

ASCENT RESOURCES UTICA HOLDINGS, LLC
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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 consolidated financial statements and related notes, included herein. The following discussion and analysis contains forward-looking statements that involve known and unknown risks, uncertainties and assumptions. The forward-looking statements are not historical facts, but rather reflect our future plans, estimates, beliefs and expected performance. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

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

Overview

We are an independent exploration and production company engaged in the acquisition, exploration and development of natural gas 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. For example, in December 2018, we achieved 2.4 bcfe per day of gross production and 1.9 bcfe per day of net production from only 390 gross (341 net) operated producing wells.

2018 Highlights

- In March, June, August and December, 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 $2.0 billion, decreased the sublimit for letters of credit from $647.5 million to $500.0 million, decreased the applicable interest margins by 1.25% and increased the aggregate maximum credit amount from $1.5 billion to $2.5 billion.

- In October, we issued $600.0 million in aggregate principal amount of 7.00% senior unsecured notes due November 2026 (2026 Notes). 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.

- 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 $463.9 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 $766.1 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 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 $501.7 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 year ended December 31, 2018, we spud 119 wells, hydraulically fractured 119 wells and turned-in-line 102 new wells.

Well Data

As of December 31, 2018, we held an interest in approximately 647 gross (360 net) productive wells, including 580 gross (360 net) properties in which we held a working interest and 67 gross properties in which we only held an overriding or royalty interest. Of the wells in which we had a working interest, 547 gross (343 net) were classified as natural gas productive wells and 33 gross (17 net) were classified as oil productive wells. We operated approximately 396 gross (343 net) of our 580 gross (360 net) productive wells in which we had a working interest. During 2018, we drilled 102 gross (80 net) wells as operator and held an overriding or royalty interest in another 8 gross wells drilled by other operators. We operated approximately 98% of our daily production volumes in 2018.

Drilling Activity

The following table describes the productive wells we drilled or participated in during the years ended December 31, 2018, 2017 and 2016:

	Productive Wells Drilled during the Years Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development	110	80	100	76	85	27

As of December 31, 2018, we had 77 gross (64 net) wells in the process of drilling, completing or turning-in-line. We did not drill any exploratory or dry development wells during the years ended December 31, 2018, 2017 or 2016.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2018 related to our leasehold acreage position. Developed acreage is acreage spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas or oil, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional working interests owned in gross acres equals one.

The following table sets forth our gross and net acres of developed and undeveloped natural gas and oil leasehold as of December 31, 2018:

Developed Acres		Undeveloped Acres		Total Acres	
Gross	Net[(a)]	Gross	Net[(a)(b)]	Gross	Net[(a)]
83,304	82,211	268,591	228,786	351,895	310,997

(a) We also own royalty interests on approximately 71,000 fee mineral acres.
(b) Approximately 50% of our net undeveloped leasehold acreage is not subject to expiration because it is held by production, or it is acreage for which we own the mineral rights.

The following table sets forth the number of total undeveloped acres as of December 31, 2018 that will expire unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such leasehold rights are extended or renewed:

	Acres Subject to Expiration	
	Gross	Net
2019	22,014	19,799
2020	14,086	12,851
2021	14,871	13,871
2022	40,604	39,838
2023 and thereafter	28,869	27,286
Total	120,444	113,645

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell natural gas and ethane. We believe we will have sufficient production quantities and firm transportation capacity to meet substantially all of such commitments; however, we may be required to purchase natural gas or ethane from third parties to satisfy shortfalls should they occur. The following table includes our firm sales commitments as of December 31, 2018:

	Natural Gas (mmbtu)	Ethane (bbl)
2019	101,413,340	1,418,750
2020	105,977,620	1,409,100
2021	104,780,550	3,229,155
2022	104,780,550	3,229,155
2023	104,780,550	3,229,155
2024	27,143,370	3,238,002
2025	—	3,229,155
2026	—	3,229,155
Total	548,875,980	22,211,627

Production Volumes, Sales Prices, Lease Operating Expenses and Gathering, Processing and Transportation Expenses

The following table sets forth information regarding our production volumes, average sales prices received, lease operating expenses and gathering, processing and transportation 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.

	Years Ended December 31,		
	2018	2017	2016
Net Production Volumes:			
Natural gas (mmcf)	457,747	240,980	109,714
Oil (mbbls)	2,262	2,492	2,035
NGL (mbbls)	3,974	3,286	2,588
Natural Gas Equivalent (mmcfe)	495,168	275,653	137,451
Average Sales Prices:			
Natural gas ($/mcf)	$ 3.16	$ 2.93	$ 2.39
Oil ($/bbl)	$ 59.15	$ 44.71	$ 33.19
NGL ($/bbl)	$ 27.48	$ 23.45	$ 14.23
Natural Gas Equivalent ($/mcfe)	$ 3.41	$ 3.25	$ 2.67
Settlements of commodity derivatives ($/mcfe)	(0.11)	0.08	0.03
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.30	$ 3.33	$ 2.70
Operating Expenses ($/mcfe):			
Lease operating expenses	$ 0.10	$ 0.13	$ 0.18
Gathering, processing and transportation expenses	$ 1.33	$ 1.24	$ 1.36

Natural Gas, Oil and NGL Reserves

The following table sets forth our proved reserves as of December 31, 2018. All of our estimated reserves are located within the Utica Shale.

	December 31, 2018			
	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)
Proved developed reserves[a]	2,846,772	16,659	47,046	3,228,997
Proved undeveloped reserves	3,889,701	25,785	57,059	4,386,766
Total	6,736,473	42,444	104,105	7,615,763

(a) Approximately 463.9 bcfe, or 14%, of our proved developed reserves were non-producing.

The table below sets forth information as of December 31, 2018, with respect to our estimated proved reserves, the associated estimated future net revenue, the present value (discounted at an annual rate of 10%) of the associated estimated future net revenue (PV-10) and the standardized measure of discounted cash flows. Neither the estimated future net revenue, PV-10 nor the standardized measure is intended to represent the current market value of the estimated natural gas, oil and NGL reserves we own. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs under existing economic conditions as of December 31, 2018. For the purpose of determining prices used in our reserve reports, we used the unweighted arithmetic average of the prices on the first day of each month within the 12-month period ended December 31, 2018. The prices used in our reserve reports were $3.10 per mmbtu of natural gas and $65.56 per bbl of oil and condensate, before basis differential adjustments. These prices should not be interpreted as a prediction of future prices, nor do they reflect the prices used to value our commodity derivative instruments in place as of December 31, 2018. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization (DD&A). PV-10 is a non-GAAP measure that typically differs from the standardized measure, because the former does not include the effects of estimated future income tax expense. However, because we are a disregarded entity for income tax purposes, we have estimated no future income tax expense and the two measures are the same as of December 31, 2018. PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis.

	December 31, 2018		
$ in thousands	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$ 5,853,432	$ 6,459,806	$ 12,313,238
PV-10	$ 3,319,818	$ 2,630,762	$ 5,950,580
Standardized measure[a]			$ 5,950,580

(a) See Note 11, *Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves*, of the notes to our consolidated financial statements included in this report for further discussion.

As of December 31, 2018, our estimated proved reserves included approximately 4.387 tcfe of reserves classified as proved undeveloped, compared to approximately 2.672 tcfe as of December 31, 2017. The table below is a summary of changes in our proved undeveloped reserves (PUDs) for 2018:

	Total (mmcfe)
Proved undeveloped reserves at December 31, 2017	2,672,218
Extensions, discoveries and other additions	1,893,104
Revisions	822,093
Purchases of reserves	409,081
Conversions into proved developed reserves	(1,409,730)
Proved undeveloped reserves at December 31, 2018	4,386,766

As of December 31, 2018, there were no PUDs that had remained undeveloped for five years or more. Our proved undeveloped extensions and discoveries of approximately 1.893 tcfe of reserves resulted from the continued development of our Utica Shale acreage. Revisions of previous estimates included upward revisions of 1.489 tcfe due to improved drilling and operating efficiencies, including the impact from extended laterals, upward revisions of 22.0 bcfe due to higher commodity prices and downward revisions of 688.9 bcfe resulting primarily from removing PUDs where it was determined development would occur outside of our five-year development plan. We added 409.1 bcfe of proved undeveloped reserves through acquisitions. In 2018, we invested $436.4 million to convert 1.410 tcfe to proved developed reserves. In 2019, we estimate that we will invest approximately $484.5 million for PUD conversions to proved developed reserves.

The future net revenues attributable to our estimated PUDs of $6.5 billion as of December 31, 2018, and associated PV-10 of $2.6 billion, have been calculated assuming that we will expend approximately $2.1 billion to develop these reserves ($484.5 million in 2019, $447.1 million in 2020, $387.8 million in 2021, $421.5 million in 2022 and $396.5 million in 2023), although the amount and timing of these expenditures will depend on a number of factors, including, but not limited to, actual drilling results, service costs, commodity prices and the availability of capital. Our developmental drilling schedule is subject to revision and reprioritization throughout the year resulting from unpredictable factors such as unexpected drilling results, title issues and infrastructure availability or constraints.

Evaluation and Review of Reserves

Our proved reserve estimates as of December 31, 2018 were prepared by Software Integrated Solutions (SIS) (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation, our independent reserve engineers. Within SIS, the technical person primarily responsible for preparing the estimates set forth in the reserve reports is Mr. Charles M. Boyer II, PG, CPG. Mr. Boyer has over 25 years of practical domestic and international experience in the estimation and evaluation of petroleum reserves. He is an active member of the Society of Petroleum Evaluation Engineers, the Society of Petroleum Engineers and the American Association of Petroleum Geologists. As technical principal, Mr. Boyer meets or exceeds the education, training and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers and is proficient in applying industry standard practices to engineering evaluations as well as applying SEC and other industry reserves definitions and guidelines. Mr. Boyer does not own an interest in any of our properties, nor is he employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Appalachian Basin. Our internal technical team members meet with our independent reserve engineers periodically during the preparation of the reserve reports to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to the independent reserve engineers for our properties, such as ownership interest, natural gas, oil and NGL production, well test data, commodity prices and operating and development costs. Mr. Daniel E. Hensley, our Vice President - Exploration and Resource Development, is primarily responsible for overseeing the preparation of all our reserve estimates. Mr. Hensley is a petroleum engineer with over 21 years of reservoir estimation and operations experience, and our engineering and geoscience staff have an average of approximately 15 years of industry experience.

The preparation of our historical proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- Verification of property ownership by our land department;
- Verification of various state severance and ad valorem tax rates by our tax department;
- Review and verification of historical production data, which data is based on actual production as reported by us;
- Review and verification of historical lease operating expenses, which data is based on actual accounting data as reported by us;
- Review and verification of historical capital expenditures, which data is based on actual accounting data as reported by us;
- Review and verification of historical realized pricing differentials and marketing contract fees, which data is based on actual accounting data as reported by us;
- Review of our proved undeveloped wells to ensure that the timing and future rates of production are consistent with current development plans and our financial ability to develop such reserves within five years;
- Review of reserve estimates by Mr. Hensley or under his direct supervision; and
- Review by our Chief Executive Officer, Chief Financial Officer and Chief Operating Officer of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new PUD additions.

Selected Financial Data

The following table presents summary consolidated financial data for each of the periods indicated. Summary historical financial data as of and for the years ended December 31, 2018, 2017 and 2016 is derived from the audited consolidated financial statements. The financial data included may not be indicative of our future results.

	Years Ended December 31,		
$ in thousands	2018	2017	2016
Statements of operations data:			
Revenues:			
Natural gas	$ 1,444,368	$ 706,866	$ 262,765
Oil	133,786	111,441	67,551
NGL	109,221	77,054	36,833
Commodity derivative (loss) gain	(90,881)	212,046	(86,434)
Total Revenues	1,596,494	1,107,407	280,715
Operating Expenses:			
Lease operating expenses	50,163	35,259	24,061
Gathering, processing and transportation expenses	658,117	341,765	186,300
Production and ad valorem taxes	23,362	14,050	7,623
Exploration expenses	156,450	186,152	269,982
General and administrative expenses, including related party	63,794	46,325	34,999
Acquisition expenses	9,407	—	—
Natural gas and oil depreciation, depletion and amortization	500,773	305,573	229,038
Depreciation and amortization of other assets	3,912	1,905	1,864
Impairment of other property and equipment	—	—	2,222
Total Operating Expenses	1,465,978	931,029	756,089
Income (Loss) From Operations	130,516	176,378	(475,374)
Other (Expense) Income:			
Interest expense, net	(91,197)	(69,062)	(88,159)
Acquisition obligation accretion expense	(1,030)	(4,290)	(10,108)
Change in fair value of embedded derivative	18,865	(19,261)	3,616
(Losses) gains on purchases or exchanges of debt	(62,233)	(114,052)	207,470
Other income	683	1,572	2,001
Total Other (Expense) Income	(134,912)	(205,093)	114,820
Net Loss	$ (4,396)	$ (28,715)	$ (360,554)
Balance sheets data (at period end):			
Cash and cash equivalents	$ 11,030	$ 119,215	$ 268,493
Total assets	$ 6,486,822	$ 4,213,869	$ 3,793,458
Total long-term debt, net	$ 2,582,820	$ 1,564,774	$ 1,325,325
Total liabilities	$ 3,271,725	$ 2,031,369	$ 1,726,275
Total liabilities and Member’s equity	$ 6,486,822	$ 4,213,869	$ 3,793,458

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 (gains) on purchases or exchanges of debt; changes in fair value of commodity derivatives; changes in fair value of embedded derivative; non-recurring legal expense (benefit); acquisition expenses; incentive units (income) expense; and impairment of other property and equipment. We define EBITDAX as net income (loss) before exploration expenses; DD&A; interest expense, net; and acquisition obligation accretion. We define adjusted EBITDAX as EBITDAX before changes in fair value of embedded derivative; losses (gains) on purchases or exchanges of debt; changes in fair value of commodity derivatives; non-recurring legal expense (benefit); acquisition expenses; incentive units (income) expense; impairment of other property and equipment; 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 (loss):

	Years Ended December 31,		
($ in thousands)	**2018**	**2017**	**2016**
Net Loss	$ (4,396)	$ (28,715)	$ (360,554)
Adjustments to reconcile net loss to adjusted net income (loss):			
Impairment of unproved natural gas and oil properties	153,047	183,885	252,845
Losses (gains) on purchases or exchanges of debt	62,233	114,052	(207,470)
Change in fair value of commodity derivatives	34,138	(188,650)	90,832
Change in fair value of embedded derivative	(18,865)	19,261	(3,616)
Non-recurring legal expense (benefit)	9,428	—	(4,147)
Acquisition expenses	9,407	—	—
Incentive units (income) expense	(1,344)	2,629	733
Impairment of other property and equipment	—	—	2,222
Adjusted Net Income (Loss) (Non-GAAP)	$ 243,648	$ 102,462	$ (229,155)

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

	Years Ended December 31,		
($ in thousands)	2018	2017	2016
Net Loss	$ (4,396)	$ (28,715)	$ (360,554)
Adjustments to reconcile net loss to EBITDAX:			
Exploration expenses	156,450	186,152	269,982
Natural gas and oil depreciation, depletion and amortization	500,773	305,573	229,038
Depreciation and amortization of other assets	3,912	1,905	1,864
Interest expense, net	91,197	69,062	88,159
Acquisition obligation accretion expense	1,030	4,290	10,108
EBITDAX (Non-GAAP)	748,966	538,267	238,597
Adjustments to reconcile EBITDAX to Adjusted EBITDAX:			
Change in fair value of embedded derivative	(18,865)	19,261	(3,616)
Losses (gains) on purchases or exchanges of debt	62,233	114,052	(207,470)
Change in fair value of commodity derivatives	34,138	(188,650)	90,832
Non-recurring legal expense (benefit)	9,428	—	(4,147)
Acquisition expenses	9,407	—	—
Incentive units (income) expense	(1,344)	2,629	733
Impairment of other property and equipment	—	—	2,222
Adjusted EBITDAX (Non-GAAP)	$ 843,963	$ 485,559	$ 117,151

We had adjusted net income (loss) of $243.6 million, $102.5 million and $(229.2) million during the years ended December 31, 2018, 2017 and 2016, respectively, demonstrating year-over-year increases of $141.1 million and $331.7 million in 2018 and 2017, respectively. Adjusted EBITDAX was $844.0 million, $485.6 million and $117.2 million for the years ended December 31, 2018, 2017 and 2016, respectively, demonstrating year-over-year increases of $358.4 million and $368.4 million in 2018 and 2017, respectively. The increases in these non-GAAP measures for the year ended December 31, 2018 compared to 2017 and 2016 are primarily due to increases in the volume and price of natural gas produced.

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. Cash flows from operations, cash on hand and draws on our credit facility will be our primary sources of liquidity in the future.

As of December 31, 2018, we had a cash balance of $11.0 million. In December 2018, the borrowing base under the Credit Facility was redetermined and adjusted to a fully committed amount of $2.0 billion, and the aggregate maximum credit amount was increased to $2.5 billion in June 2018. As of March 7, 2019, we had borrowings of $915.0 million and $330.6 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 2019 compared to 2018 due to expected increased production related to our drilling and completions program. 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:

($ in thousands)	Years Ended December 31, 2018	2017	2016
Cash provided by operating activities	$ 688,733	$ 485,444	$ 92,792
Proceeds from credit facility borrowings	1,525,000	—	—
Contributions from Member	567,647	132,000	1,331,719
Proceeds from divestitures of natural gas and oil properties	6,564	79,329	16,664
Proceeds from issuance of long-term debt, net	587,166	1,466,250	—
Reductions in deposits on pipeline capacity	—	151,193	—
Total Sources of Cash and Cash Equivalents	$ 3,375,110	$ 2,314,216	$ 1,441,175

Net cash flow provided by operating activities was approximately $688.7 million, $485.4 million and $92.8 million for the years ended December 31, 2018, 2017 and 2016, respectively. The increases in operating cash flow in 2018 and 2017 were primarily the result of increased natural gas production and realized prices year-over-year.

During the year ended December 31, 2018, we received a net $587.2 million in cash from the issuance of the 2026 Notes. We used approximately $577.5 million of the net proceeds to exercise our 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 any accrued and unpaid interest, and the remaining net proceeds were used to repay borrowings under the Credit Facility. We borrowed $1.525 billion from our Credit Facility during the year ended December 31, 2018 and repaid $577.0 million during the same period. Additionally, we paid $9.5 million of debt issuance costs related to redeterminations of our Credit Facility and $2.2 million related to the issuance of the 2026 Notes. In addition, we received $567.6 million in net cash contributions from equity capital raised by our Parent to partially fund the CNX and Hess Acquisition and the UMD Acquisition. We also received $6.6 million related to the divestiture of natural gas and oil properties.

During the year ended December 31, 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 (as defined below). Additionally, we paid $14.8 million of debt issuance costs related to the Credit Facility and $3.3 million related to the 2022 Notes. The remaining proceeds were used for general corporate purposes. We also received $132.0 million in net cash contributions from equity capital raised by our Parent in 2017. Of the equity contributions received, $100.0 million was used for general corporate purposes and $32.0 million was used to fund the acquisition of the 2017 Acquisition Properties. We also received $79.3 million in 2017 related to the 2017 Utica Divestiture. Both the 2017 Acquisition Properties and the 2017 Utica Divestiture are discussed in Note 3, *2017 Acquisitions and Divestitures*, of the notes to our consolidated financial statements included in this report. Additionally, we received $151.2 million in refunds of our cash deposits on pipeline capacity as a result of reduced credit requirements under our firm transportation commitments and the issuance of letters of credit under our Credit Facility.

During the year ended December 31, 2016, we received $1.332 billion in net cash contributions from equity capital raised by our Parent. The proceeds were used to repurchase and retire the outstanding principal and accrued and unpaid interest of our previous junior lien debt and for general corporate purposes. Also, during 2016, we sold certain unproved natural gas and oil properties in three separate transactions to third parties for $16.7 million.

Uses of Funds

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

($ in thousands)	Years Ended December 31, 2018	2017	2016
Natural Gas and Oil Expenditures:			
Drilling and completion costs	$ (906,064)	$ (653,942)	$ (268,082)
Acquisitions of natural gas and oil properties	(1,313,342)	(323,341)	(267,582)
Interest capitalized on unproved leasehold	(96,152)	(106,549)	(160,719)
Additions to deposits on pipeline capacity	—	—	(41,811)
Total Natural Gas and Oil Expenditures	(2,315,558)	(1,083,832)	(738,194)
Other Uses of Cash and Cash Equivalents:			
Repayment of credit facility borrowings	(577,000)	—	—
Cash paid for debt issuance costs	(11,725)	(18,142)	(15,474)
Additions to other property and equipment	(1,512)	(257)	(715)
Repayment of debt	(525,000)	(1,290,264)	(464,649)
Cash paid for debt prepayment costs	(52,500)	(70,999)	(667)
Repayment of note payable to third party	—	—	(37,170)
Total Other	(1,167,737)	(1,379,662)	(518,675)
Total Uses of Cash and Cash Equivalents	$ (3,483,295)	$ (2,463,494)	$ (1,256,869)

Our drilling and completion costs were $906.1 million, $653.9 million and $268.1 million for the years ended December 31, 2018, 2017 and 2016 respectively. The increase is primarily the result of increased drilling and completion activity year-over-year. During the year ended December 31, 2018, our average operated rig count was seven rigs, compared to an average operated rig count of five rigs in 2017 and two rigs in 2016. We spud 119 wells, hydraulically fractured 119 wells and turned-in-line 102 new wells during the year ended December 31, 2018, compared to 2017 during which we spud 81 wells, hydraulically fractured 80 wells and turned-in-line 88 new wells and to 2016 during which we spud 28 wells, hydraulically fractured 45 wells and turned-in-line 26 new wells.

We spent cash of $766.1 million to fund the CNX and Hess Acquisition and $263.2 million to fund the UMD Acquisition, which are included in our natural gas and oil property acquisition costs during the year ended December 31, 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 consolidated financial statements included in this report. We spent additional cash of $284.0 million, $323.3 million and $267.6 million during the years ended December 31, 2018, 2017 and 2016 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 executed amendments to the Credit Facility in March, June, August and December of 2018, which, in aggregate, increased the borrowing base from $925.0 million to a fully committed $2.0 billion, decreased the sublimit for letters of credit from $647.5 million to $500.0 million, decreased the applicable interest margins by 1.25% and increased the aggregate maximum credit amount from $1.5 billion to $2.5 billion. As of December 31, 2018, we had borrowings of $948.0 million and $370.6 million of letters of credit outstanding under the Credit Facility. As of March 7, 2019, we had borrowings of $915.0 million and $330.6 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 0.50% to 1.50% 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 1.50% to 2.50% per annum. Due to the weighted average 1-month LIBOR being 2.36% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.36% per annum as of December 31, 2018. We may repay any amounts borrowed prior to the maturity date without any premium or penalty. 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 December 31, 2018, we were in compliance with all applicable financial covenants under the Credit Facility. See Note 5, *Credit Facility*, of the notes to our consolidated financial statements included in this report for further discussion of the terms of the Credit Facility.

Senior Notes

In October 2018, we issued $600.0 million in aggregate principal amount of the 2026 Notes in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. 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. We used approximately $577.5 million of the $587.2 million net proceeds from the issuance of the 2026 Notes for the Redemption. We also paid $1.5 million of accrued and unpaid interest up to, but excluding, the date of the Redemption. We incurred a loss of $62.2 million in October 2018 related to the Redemption. We used the remaining net proceeds to repay borrowings under the Credit Facility.

In April 2017, we 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. Our net proceeds of $1.466 billion were used to repay and retire all of our outstanding second lien term loans (Second Lien Term Loans) and for general corporate purposes.

At any time prior to November 1, 2021, we may redeem up to 40% of the aggregate principal amount of the 2026 Notes at a price equal to 107% of the principal amount, plus accrued and unpaid interest up to, but excluding, the redemption date, with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020 for the 2022 Notes or November 1, 2021 for the 2026 Notes (together, the Senior Notes), we may redeem some or all of the Senior Notes subject to a make-whole premium plus accrued and unpaid interest to, but excluding, the redemption date. We may redeem some or all of the Senior Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below on the dates set forth therein:

Senior Notes	Redemption on or after	Redemption Price
2022 Notes	April 1, 2020	107.500%
2022 Notes	April 1, 2021	105.000%
2022 Notes	October 1, 2021 and thereafter	100.000%
2026 Notes	November 1, 2021	103.500%
2026 Notes	November 1, 2022	102.333%
2026 Notes	November 1, 2023	101.167%
2026 Notes	November 1, 2024 and thereafter	100.000%

We are not prohibited from acquiring the Senior 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 applicable indenture. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the Senior Notes at a purchase price in cash equal to 101% of the aggregate principal amount of the Senior Notes to be repurchased, plus accrued and unpaid interest.

The Senior 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 Senior 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 December 31, 2018, we were in compliance with all applicable covenants of the 2022 Notes and 2026 Notes indentures. See Note 5, *Senior Notes*, of the notes to our consolidated financial statements included in this report for further discussion of the terms of the 2022 Notes and 2026 Notes.

Convertible Notes

In 2014, we issued $1.0 billion of convertible notes due 2021 (Convertible Notes). Through multiple transactions from 2015 through 2017, we repurchased or otherwise retired $950.3 million in aggregate principal and accrued and unpaid interest of the Convertible Notes, including $11.1 million of outstanding principal and accrued and unpaid interest in March 2017 contributed to us by the Member.

As of December 31, 2018, we had $74.1 million in aggregate principal, including accrued and unpaid interest, outstanding of the Convertible Notes. The Convertible Notes are subordinate to the Senior Notes, which rank senior in right of payment, and mature 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 is currently payable at an annual rate of 6.50%. We have elected to pay interest in kind on each interest payment date since September 2015. Upon maturity, unless earlier repurchased or converted, we will be required to redeem the Convertible Notes at 153.8% of the outstanding principal value, plus accrued and unpaid interest up to, but not including, the maturity date. We accrete the 53.8% premium 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 initial public offering (Qualified PO) is at the option of the noteholders. 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. Following the closing of a Qualified PO, we will have the option to redeem all of the Convertible Notes that were not otherwise 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 price, including a premium, of 153.8% of the principal amount of the Convertible Notes, plus accrued and unpaid interest up to, but not including, the date of redemption. The Convertible Notes are not redeemable by the holders prior to a change of control or the closing of a Qualified PO.

Contractual Obligations and Off-Balance Sheet Arrangements

We occasionally enter into arrangements that can give rise to contractual obligations and off-balance sheet commitments, such as pipeline transportation commitments, drilling rig commitments, and various other commitments in the ordinary course of business.

The following table summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2018:

	Payments Due by Period				
($ in thousands)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt:					
Principal[a]	$ 2,653,921	$ —	$ 1,078,921	$ 975,000	$ 600,000
Interest	875,623	211,963	403,827	133,833	126,000
Operating lease commitments[b]	7,988	3,711	4,277	—	—
Pipeline commitments[c]	10,102,695	612,488	1,306,043	1,330,739	6,853,425
Other	4,759	2,118	2,142	103	396
Total	$ 13,644,986	$ 830,280	$ 2,795,210	$ 2,439,675	$ 7,579,821

(a) Total principal amount of debt maturities.

(b) See Note 9 of the notes to our consolidated financial statements included in this report for a description of our operating lease commitments.

(c) See Note 9 of the notes to our consolidated financial statements included in this report for a description of our pipeline commitments.

Critical Accounting Policies and Estimates

Our financial statements are prepared in accordance with US GAAP. In connection with preparing our consolidated financial statements, we are required to make assumptions and estimates about future events, and apply judgments that affect the reported amounts of assets, liabilities, revenue, expense and the related disclosures. We base our assumptions, estimates and judgments on historical experience, current trends and other factors that management believes to be relevant at the time we prepare our consolidated financial statements. On a regular basis, management reviews the accounting policies, assumptions, estimates and judgments to ensure that our consolidated financial statements are presented fairly and in accordance with US GAAP. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

Our significant accounting policies are discussed in Note 1, *Significant Accounting Policies*, of the notes to our consolidated financial statements included in this report. Management believes that the following accounting estimates are those most critical to fully understanding and evaluating our reported financial results, and they require management's most difficult, subjective or complex judgments, resulting from the need to make estimates about the effect of matters that are inherently uncertain.

Natural Gas, Oil and NGL Reserves

Estimates of natural gas, oil and NGL reserves and their values, future production rates and future costs and expenses are the most significant of our estimates. Our estimates of proved reserves are based on the quantities of natural gas, oil and NGL, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods and government regulations. The accuracy of reserve estimates is a function of the:

- Quality and quantity of available data;
- Interpretation of that data;
- Accuracy of various mandated economic assumptions; and
- Judgment of the independent reserve engineer.

Natural gas, oil and NGL reserve estimates require significant judgments in the evaluation of all available geological, geophysical, engineering and economic data. The data for a given field may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, production history, projected future production, economic assumptions relating to commodity prices, operating expenses, severance and other taxes, capital expenditures and remediation costs and these estimates are inherently uncertain. For example, if estimates of proved reserves decline, the depreciation, depletion and amortization rate will increase, resulting in a decrease in net income. A decline in estimates of proved reserves could also cause us to perform an impairment analysis to determine if the carrying amount of natural gas and oil properties exceeds fair value and could result in an impairment charge, which would reduce earnings.

We are unable to predict future commodity prices, and the volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of our proved reserve portfolio, assuming no other changes to our development plans or costs. We cannot predict what reserve revisions may be required in future periods.

Natural Gas and Oil Properties

We use the successful efforts method of accounting for natural gas and oil properties, whereby costs incurred to acquire interests in properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Exploration costs, such as most geological and geophysical costs, are expensed as incurred. Under the successful efforts method of accounting, we capitalize exploratory drilling costs, including capitalized interest, in the balance sheet pending determination of whether a well has found proved reserves in economically producible quantities. If proved reserves are found by an exploratory well, the associated capitalized costs become part of proved natural gas and oil properties; however, if proved reserves are not found, the capitalized costs associated with the well are expensed, net of any salvage value, as exploration expense. Acquisition costs of unproved properties are transferred to proved properties to the extent the costs are associated with successful exploration activities.

Proved natural gas and oil properties are reviewed for impairment whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The estimated undiscounted future cash flows expected are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to its estimated fair value (typically determined using discounted future cash flows). No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2018, 2017 or 2016. We cannot predict whether impairment charges may be required in the future as commodity prices of natural gas, oil and NGL have a significant impact on determining future impairments.

Unproved natural gas and oil properties primarily consist of undeveloped leasehold costs. Individually significant unproved properties, if any, are assessed for impairment on a property-by-property basis and, if the assessment indicates an impairment, a loss is recognized. For individually insignificant unproved properties, impairment losses are recognized by amortizing to exploration expense the portion of the properties' costs that management estimates will not be transferred to proved properties over the remaining lease term. Our impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2018, 2017 and 2016, we recorded impairments of $153.0 million, $183.9 million and $252.8 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

Natural Gas and Oil Depreciation, Depletion and Amortization

Natural gas and oil DD&A of capitalized drilling and completion costs of producing natural gas and oil properties is computed using the unit-of-production method, based on total estimated proved developed natural gas, oil and NGL reserves. Costs of acquiring proved properties, including leasehold acquisition costs and capitalized interest transferred from unproved properties, are depleted using the unit-of-production method based on total estimated proved natural gas, oil and NGL reserves.

Business Combinations

We account for all business combinations using the acquisition method, which involves the use of significant judgment. In a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill.

We estimate the fair values of assets acquired and liabilities assumed in a business combination using various assumptions (all of which are Level 3 inputs within the fair value hierarchy). The most significant assumptions typically relate to the estimated fair values assigned to proved and unproved natural gas and oil properties. To estimate the fair values of the proved and unproved natural gas and oil properties, we develop estimates of natural gas, oil and NGL reserves. Estimates of reserves are based on the quantities of natural gas, oil and NGL that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Additionally, a risk factor is applied to reserves by reserve type based on industry standards. We estimate future prices to apply to the estimated net quantities of reserves based on the applicable ownership percentage acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. The future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition.

Asset Acquisitions

As part of our business strategy, we periodically pursue the acquisition of natural gas and oil properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable natural gas, oil and NGL reserves and unproved natural gas and oil properties.

Asset Retirement Obligations

We recognize liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the assets. We recognize the fair value of a retirement obligation in the period in which the obligation is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The liability is then accreted to its present value each period, until it is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of our natural gas and oil properties and expensed through depletion of the asset. The accretion expense is recorded as a component of DD&A in our consolidated statements of operations.

Revenue Recognition

Revenue from the sale of natural gas, oil and NGL is recognized when production is sold to a customer at a fixed or determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. We recognize revenues from the sale of natural gas, oil and NGL based on our share of volumes sold. We adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 606) with an effective date as of January 1, 2018 using the modified retrospective transition approach. See Note 2 of the notes to our consolidated financial statements included in this report for further discussion of our implementation of ASC 606.

Fair Value of Financial Instruments

Certain financial instruments are reported at fair value on the consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

Commitments and Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Liabilities for environmental remediation or restoration claims resulting from allegations of improper operation of assets are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with our accounting policy for property and equipment.

Derivatives

We periodically enter into commodity derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our expected operating cash flow against significant market movements or volatility. All commodity derivative instruments are recognized at their current fair value as either assets or liabilities on the consolidated balance sheets. Changes in the fair value of these commodity derivative instruments are recorded in earnings unless specific hedge accounting criteria are met. We elected not to designate any of our commodity derivative instruments for hedge accounting treatment. By using commodity derivative instruments, we are exposed to credit risk associated with our hedge counterparties. 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 we determine are creditworthy. The creditworthiness of our counterparties is subject to periodic review.

Derivative instruments reflected as current on the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices or rates as of the respective balance sheet dates. Cash settlements of our derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows. All of our derivative instruments are subject to International Swaps and Derivatives Association (ISDA) master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, by counterparty. ISDA master agreements also provide for net settlement over the term of the contract and in the event of default or termination of the contract. We net the value of our derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

We have established the fair value of our derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to our counterparty values for reasonableness. The values we report in our financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations and are also subject to the risk of our non-performance. This non-performance risk is considered in the valuation of our derivative instruments, but to date has not had a material impact on the values of our derivatives. See Note 6 of the notes to our consolidated financial statements included in this report for further discussion of our derivative instruments.

New Accounting Pronouncements

See Note 1, *Adopted and Recently Issued Accounting Pronouncements,* of the notes to our consolidated financial statements included in this report 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.

	Years Ended December 31,		
	2018	2017	2016
Net Production Volumes:			
Natural gas (mmcf)	457,747	240,980	109,714
Oil (mbbls)	2,262	2,492	2,035
NGL (mbbls)	3,974	3,286	2,588
Natural Gas Equivalent (mmcfe)	495,168	275,653	137,451
Natural Gas, Oil and NGL Sales ($ in thousands):			
Natural gas	$ 1,444,368	$ 706,866	$ 262,765
Oil	133,786	111,441	67,551
NGL	109,221	77,054	36,833
Settlements of commodity derivatives	(56,743)	23,396	4,398
Change in fair value of commodity derivatives	(34,138)	188,650	(90,832)
Total	$ 1,596,494	$ 1,107,407	$ 280,715
Average Daily Net Production Volumes:			
Natural gas (mmcf/d)	1,254	660	300
Oil (mbbls/d)	6	7	6
NGL (mbbls/d)	11	9	7
Natural Gas Equivalent (mmcfe/d)	1,357	755	376
Average Sales Prices:			
Natural gas ($/mcf)	$ 3.16	$ 2.93	$ 2.39
Oil ($/bbl)	$ 59.15	$ 44.71	$ 33.19
NGL ($/bbl)	$ 27.48	$ 23.45	$ 14.23
Natural Gas Equivalent ($/mcfe)	$ 3.41	$ 3.25	$ 2.67
Settlements of commodity derivatives ($/mcfe)	(0.11)	0.08	0.03
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.30	$ 3.33	$ 2.70
Operating Expenses ($/mcfe):			
Lease operating expenses	$ 0.10	$ 0.13	$ 0.18
Gathering, processing and transportation expenses	$ 1.33	$ 1.24	$ 1.36
Production and ad valorem taxes	$ 0.05	$ 0.05	$ 0.06
General and administrative expenses, including related party	$ 0.13	$ 0.17	$ 0.25
Natural gas and oil depreciation, depletion and amortization	$ 1.01	$ 1.11	$ 1.67
Depreciation and amortization of other assets	$ 0.01	$ 0.01	$ 0.01

General. In 2018, 2017 and 2016, we had net losses of $4.4 million, $28.7 million and $360.6 million respectively, on total revenues of $1.6 billion, $1.1 billion and $280.7 million, respectively. In 2018, we had income from operations of $130.5 million which was offset by the loss related to the Redemption of 2022 Notes and interest expense associated with our long-term debt. In 2017, we had income from operations of $176.4 million which was offset by the loss related to the retirement of the Second Lien Term Loans and interest expense associated with our long-term debt. In 2016, we had a loss from operations of $475.4 million due to a low commodity price environment, exploration expenses and a high rate of natural gas and oil depreciation, depletion and amortization, which was partially offset by a gain related to the Exchange Offer and subsequent redemption of the Convertible Notes in February and April 2016.

Natural Gas Sales. In 2018, 2017 and 2016, natural gas sales (excluding the effects of derivatives) were $1.4 billion, $706.9 million and $262.8 million, respectively. During 2018, 2017 and 2016, we sold 457.7 bcf, 241.0 bcf and 109.7 bcf of natural gas, at weighted average prices of $3.16, $2.93 and $2.39 per mcf, respectively (excluding the effects of derivatives). The $737.5 million increase in natural gas sales (excluding the effects of derivatives) in 2018 compared to 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 $444.1 million increase in natural gas sales (excluding the effect of derivatives) in 2017 compared to 2016 was driven by a 120% increase in natural gas production, as well as a 23% increase in average sales prices received for natural gas.

Gains and losses from our natural gas derivatives resulted in a $146.8 million decrease, a $213.0 million increase and a $79.9 million decrease in natural gas revenues in 2018, 2017 and 2016, respectively. We paid net cash of $42.9 million in 2018 and received net cash of $16.8 million and $5.7 million in 2017 and 2016, respectively, for natural gas hedging settlements.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our 2018 production levels 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 $45.8 million in 2018.

Oil Sales. In 2018, 2017 and 2016, oil sales (excluding the effects of derivatives) were $133.8 million, $111.4 million and $67.6 million, respectively. In 2018, 2017 and 2016, we sold 2,262 mbbls, 2,492 mbbls and 2,035 mbbls at weighted average prices of $59.15, $44.71 and $33.19 per bbl, respectively, (excluding the effects of derivatives). The $22.4 million increase in oil sales (excluding the effects of derivatives) in 2018 compared to 2017 was driven by a 32% increase in the average sales price received for oil and offset by a 9% decrease in oil production. The $43.8 million increase in oil sales (excluding the effects of derivatives) in 2017 compared to 2016 was driven by a 22% increase in oil production, as well as a 35% increase in average sales prices received for oil.

Gains and losses from our oil derivatives resulted in a $37.8 million increase, a $1.0 million decrease, and a $6.6 million decrease in oil revenues in 2018, 2017 and 2016, respectively. We paid net cash of $17.1 million and $1.3 million in 2018 and 2016, respectively, and received net cash of $6.6 million in 2017 for oil hedging settlements.

A change in oil prices has a direct impact on our sales and cash flows. Assuming our 2018 production levels 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 $2.3 million in 2018.

NGL Sales. In 2018, 2017 and 2016, NGL sales (excluding the effects of derivatives) were $109.2 million, $77.1 million and $36.8 million, respectively. During 2018, 2017 and 2016, we sold 3,974 mbbls, 3,286 mbbls and 2,588 mbbls, respectively, of NGL at weighted average prices of $27.48, $23.45 and $14.23 per bbl, respectively, (excluding the effects of derivatives). The $32.1 million increase in NGL sales (excluding the effects of derivatives) in 2018 compared to 2017 was driven by a 17% increase in the average sales price received for NGL and a 21% increase in NGL production. The $40.3 million increase in NGL sales (excluding the effects of derivatives) in 2017 compared to 2016 was driven by a 27% increase in NGL production, as well as a 65% increase in average sales prices received for NGL.

Gains and losses from our NGL derivatives resulted in an $18.2 million increase in NGL revenues in 2018. We received net cash of $3.3 million in 2018 for NGL hedging settlements.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our 2018 production levels 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 $4.0 million in 2018.

Lease Operating Expenses. Lease operating expenses were $50.2 million, $35.3 million and $24.1 million in 2018, 2017 and 2016, respectively. On a per unit basis, lease operating expenses were $0.10, $0.13 and $0.18 per mcfe during 2018, 2017 and 2016, respectively. The per unit decrease from 2017 to 2018 was primarily the result of increased levels of production and operating efficiencies, including the reuse of saltwater during hydraulic fracturing, reduction in fuel transportation and reduction in contract labor. The per unit decrease from 2016 to 2017 was primarily the result of operating efficiencies, including implementation of preventative maintenance programs and improvements in our well management, facility construction and artificial lift techniques.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $658.1 million, $341.8 million and $186.3 million in 2018, 2017 and 2016, respectively. On a per unit basis, gathering, processing and transportation expenses were $1.33, $1.24 and $1.36 per mcfe during 2018, 2017 and 2016, respectively. The per unit increase from 2017 to 2018 was due to increases in contracted in-service firm transportation capacity in excess of increases in production volumes. The per unit decrease from 2016 to 2017 was due to increased annual production, which reduced expenses related to unused firm transportation.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $23.4 million, $14.1 million and $7.6 million in 2018, 2017 and 2016, respectively. Production taxes have increased as production volumes have increased and were $14.9 million, $8.1 million and $4.0 million in 2018, 2017 and 2016, respectively. Production taxes are calculated using volume-based formulas that produce higher absolute costs as production increases. On a per unit basis, production taxes remained consistent and were $0.03 per mcfe during 2018, 2017 and 2016, respectively. Ad valorem taxes were $8.5 million, $6.0 million and $3.6 million in 2018, 2017 and 2016, respectively. Ad valorem taxes are assessed annually based on wells producing at the end of the previous 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 $156.5 million, $186.2 million and $270.0 million in 2018, 2017 and 2016, respectively. We impaired $153.0 million, $183.9 million and $252.8 million during 2018, 2017 and 2016, 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 $63.8 million, $46.3 million and $35.0 million in 2018, 2017 and 2016, respectively. On a per unit basis, general and administrative expenses, including related party expenses, were $0.13, $0.17 and $0.25 per mcfe during 2018, 2017 and 2016, respectively. Total general and administrative expenses, including related party, have increased in 2018 primarily due to a 10% increase in our employee count and related costs from December 31, 2017 to December 31, 2018 and $9.4 million of non-recurring legal expenses. The absolute increases in general and administrative expenses, including related party, were offset by an 80% increase in production volumes in 2018 compared to 2017, creating the decreases on a per unit basis. The combined per unit expense decrease in 2017 compared to 2016 was primarily due to increased production in 2017.

Acquisition Expenses. Acquisition expenses of $9.4 million were incurred during 2018 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 consolidated financial statements included in this report. The incurred acquisition expenses were primarily related to legal services, due diligence expenses and filing fees. Due to these acquisitions being accounted for as business combinations, these expenses were not capitalized.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $500.8 million, $305.6 million and $229.0 million in 2018, 2017 and 2016, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs and the related underlying reserves, was $1.01, $1.11 and $1.67 per mcfe during 2018, 2017 and 2016, respectively. The per unit decrease from 2017 to 2018 was the result of a 79% increase in total proved reserves, which was only partially offset by a 57% increase in net capitalized costs during the same period. The per unit decrease from 2016 to 2017 was the result of a 137% increase in total proved reserves, which was only partially offset by a 61% 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 consolidated financial statements included in this report.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $3.9 million in 2018 and $1.9 million in 2017 and 2016. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. Our other property and equipment consist mainly of a field office and other corporate assets. The increase in 2018 from 2017 and 2016 was the result of a management services agreement being assigned from our Member to Ascent Resources Management Services, LLC (ARMS), our wholly-owned subsidiary, on January 1, 2018. As part of the assignment, our Member contributed all of its property and equipment to ARMS. See Note 8, *Management Services Agreement*, of the notes to our consolidated financial statements included in this report for further discussion.

Impairment of Other Property and Equipment. In 2016, we recorded a $2.2 million impairment associated with pipeline and gathering assets determined to no longer be in service and deemed obsolete.

Interest Expense. Interest expense was $91.2 million, $69.1 million and $88.2 million in 2018, 2017 and 2016, respectively, detailed as follows along with weighted average borrowings:

	Years Ended December 31,		
($ in thousands)	2018	2017	2016
Interest expense on 2022 Notes	$ 138,762	$ 110,448	$ —
Interest expense on 2026 Notes	9,333	—	—
Interest expense on Credit Facilities	41,073	14,908	72
Interest expense on Convertible Notes	4,320	3,552	10,754
Interest expense on Second Lien Term Loans	—	37,502	162,410
Interest expense on Junior Lien Debt	—	—	94,912
Other	2,733	3,293	4,209
Amortization of debt discount and issuance costs	21,382	21,632	39,452
Capitalized interest	(126,406)	(122,273)	(223,650)
Total Interest Expense, net	$ 91,197	$ 69,062	$ 88,159
Weighted Average 2022 Notes borrowings	$ 1,382,055	$ 1,109,589	$ —
Weighted Average 2026 Notes borrowings	134,795	—	—
Weighted Average Credit Facility borrowings	420,345	—	—
Weighted Average Convertible Notes borrowings	70,833	69,358	279,382
Weighted Average Second Lien Term Loans borrowings	—	335,822	1,280,805
Weighted Average Junior Lien borrowings	—	—	587,459
Weighted Average Borrowings	$ 2,008,028	$ 1,514,769	$ 2,147,646

The increase in interest expense in 2018 compared to 2017 was primarily due to an increase in our weighted average borrowings as a result of increased Credit Facility borrowings in 2018 and the issuance of the 2026 Notes in October 2018. The increase during 2018 was partially offset by the Redemption of the 2022 Notes in October 2018.

The decrease in interest expense and amortization of debt discounts and issuance costs during 2017 compared to 2016 was primarily due to the retirement of the Second Lien Term Loans in April 2017, the repurchase and retirement of junior lien debt and accrued and unpaid interest in November 2016 and the redemption of the Convertible Notes in April 2016. This was partially offset by an increase in interest expense associated with the issuance of the 2022 Notes in April 2017 and a reduction in capitalized interest as a result of a lower weighted average interest rate.

Acquisition Obligation Accretion Expense. Acquisition obligation accretion expense was $1.0 million, $4.3 million and $10.1 million in 2018, 2017 and 2016, respectively. Pursuant to a joint venture participation agreement, this obligation related to the carried interest from an asset acquisition that required us to pay the seller's retained share of development costs for certain wells and other development operations that occurred within an AMI as defined in the agreement. This obligation was discounted using an 11% discount rate in 2018, 2017 and 2016, to reflect the imputation of interest. The balance of the joint venture participation agreement became due on September 30, 2018, and we satisfied and paid the remaining obligation in October 2018. Therefore, no further acquisition obligation accretion expenses are anticipated. See Note 9, *Joint Venture Commitment*, of the notes to our consolidated financial statements included in this report 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 $18.9 million, $(19.3) million and $3.6 million in 2018, 2017 and 2016, respectively. In general, changes in the estimated price of the Convertible Notes, the par value and accrued interest outstanding, the probability and timing of a change of control or Qualified PO, 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) Gains on Purchases or Exchanges of Debt. We recognized a loss on purchases or exchanges of debt of $62.2 million in 2018 related to the Redemption of the 2022 Notes, as discussed in Note 5, *Senior Notes*, of the notes to our consolidated financial statements included in this report. We recognized a loss on purchases or exchanges of debt of $114.1 million in 2017 related to the repayment and retirement of the Second Lien Term Loans and the retirement of a prior credit facility in April 2017. In 2016, we recognized a gain on purchases or exchanges of debt of $207.5 million primarily in connection with the Exchange Offer and subsequent redemption of the Convertible Notes in February and April 2016, respectively.

Quantitative and Qualitative Disclosure About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, oil and NGL prices, customer credit and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures.

Commodity Demand and Price Risk

Our primary market risk exposure is in the prices we receive for our natural gas, oil and NGL production. Approximately 88% of our December 31, 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 2018, 2017 and 2016, the average daily Henry Hub spot market price of natural gas was $3.12 per mmbtu, $2.96 per mmbtu and $2.52 per mmbtu, respectively, and the average daily West Texas Intermediate oil price was $64.90 per bbl, $50.85 per bbl and $43.29 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. As of December 31, 2018, our natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*. We receive a fixed price for our natural gas, oil or NGL production and pay a variable market price to the counterparty.

- *Call Options*. We sell call options in exchange for a premium, which establish the maximum price we will receive for contracted commodity volumes. At the time of settlement, if the market price exceeds the fixed price of the call option, we pay the difference to the counterparty. From time to time, we may sell future call options to obtain more favorable strike prices on swap or collar contracts.

- *Collars*. These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price, we pay the difference between market price and the strike price of the sold call to the counterparty. If the market price falls below the put strike price, we receive the difference between market price and the strike price of the purchased put from the counterparty. If the market price is between the put and the call strike prices, no payments are due to or from either party.

- *Three-Way Collars*. Three-way collars consist of a traditional collar and the sale by us of an additional put option in exchange for more favorable strike prices on purchased put or sold call options.

- *Basis Swaps*. Given that our 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, Dominion South, TCO and Tetco M-2. Under these instruments, we receive the fixed price differential and pay the floating market price differential to the counterparty for the contracted volumes.

As of December 31, 2018, we had a net asset commodity derivative position of $69.4 million. The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of December 31, 2018, the contracted weighted average natural gas prices and the estimated fair values:

	Average Volume (mmbtu/d)	Weighted Average Prices ($/mmbtu) Fixed Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ 53,038
2019	1,712,500	$ 2.86				
2020	1,340,000	$ 2.74				
2021	410,000	$ 2.73				
Collars:						5,035
2019	15,000		$ 3.40	$ 2.75		
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						203
2021	205,000		$ 2.91	$ 2.50	$ 2.00	
2022	70,000		$ 3.00	$ 2.50	$ 2.00	
Call options:						(54,670)
2019	70,500		$ 3.00			
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	170,000		$ 3.00			
2023	170,000		$ 3.00			
Basis swaps:						8,880
2019	430,000	$ (0.23)				
2020	220,000	$ (0.45)				
Total Estimated Fair Value						$ 12,486

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of December 31, 2018, the contracted weighted average oil prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
Oil:				
Swaps:				$ 46,847
2019	7,200	$ 56.26		
2020	7,500	$ 57.20		
2021	1,000	$ 60.06		
Call options:				(4,819)
2019	2,000		$ 70.00	
2020	4,750		$ 70.00	
2021	3,500		$ 70.00	
Total Estimated Fair Value				$ 42,028

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of December 31, 2018, the contracted weighted average NGL prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 14,868
2019	2,600	$ 38.55		
2020	1,000	$ 35.07		
Call options - Propane:				(1,027)
2019	1,600		$ 33.60	
2020	3,150		$ 33.60	
Swaps - Ethane:				1,083
2019	750	$ 17.01		
Total Estimated Fair Value				$ 14,924

As of December 31, 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 $117.8 million, respectively. As of December 31, 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 $6.2 million, respectively. As of December 31, 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 $1.8 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:

	Years Ended December 31,		
	2018	2017	2016
Tenaska Marketing Ventures	23%	25%	47%
Sequent Energy Management, L.P.	16%	24%	—
Marathon Petroleum Company, L.P.	—	—	16%

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 December 31, 2018, the Convertible Notes, 2022 Notes and 2026 Notes bore interest at fixed rates of 6.50%, 10.00% and 7.00%, respectively. Borrowings under the Credit Facility bear interest at a variable tiered rate based on facility usage plus the 1-month LIBOR, and the weighted average interest rate, as of December 31, 2018, was 4.36%. 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. The variable component of our interest exposes us to interest rate risk. A 1.00% increase in the LIBOR for the year ended December 31, 2018 would have resulted in an estimated $8.5 million increase in interest expense on borrowings under the Credit Facility. We had no outstanding interest rate derivatives at December 31, 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 for the years ended December 31, 2018, 2017 or 2016. 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.

Report of Independent Registered Public Accounting Firm

To the Board of Managers and Member of Ascent Resources Utica Holdings, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Ascent Resources Utica Holdings, LLC and its subsidiaries (the "Company") as of December 31, 2018 and 2017, and the related consolidated statements of operations, of member's equity and of cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the relevant ethical requirements relating to our audit, which include standards of the American Institute of Certified Public Accountants (AICPA) Code of Professional Conduct.

We conducted our audits of these consolidated financial statements in accordance with the auditing standards of the PCAOB and in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 8, 2019

We have served as the Company's auditor since 2015.

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED BALANCE SHEETS

	December 31,	
($ in thousands)	**2018**	**2017**
Current Assets:		
Cash and cash equivalents	$ 11,030	$ 119,215
Accounts receivable – natural gas, oil and NGL sales	401,814	146,788
Accounts receivable – joint interest and other	50,531	40,934
Short-term derivative assets	52,404	76,439
Other current assets	6,135	3,057
Total Current Assets	521,914	386,433
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	7,066,947	4,441,612
Other property and equipment	27,454	19,625
Less: accumulated depreciation, depletion and amortization	(1,185,772)	(678,274)
Property and Equipment, net	5,908,629	3,782,963
Other Assets:		
Long-term derivative assets	39,543	31,441
Other long-term assets	16,736	13,032
Total Assets	$ 6,486,822	$ 4,213,869
Current Liabilities:		
Accounts payable	$ 106,839	$ 75,665
Revenue payable	178,111	63,211
Accrued interest	41,510	42,438
Short-term derivative liabilities	1,068	8,660
Acquisition obligation	—	60,083
Other current liabilities	328,580	200,100
Total Current Liabilities	656,108	450,157
Long-Term Liabilities:		
Long-term debt, net	2,582,820	1,564,774
Long-term derivative liabilities	21,441	4,869
Other long-term liabilities	11,356	11,569
Total Long-Term Liabilities	2,615,617	1,581,212
Commitments and contingencies (Note 9)		
Member's Equity	3,215,097	2,182,500
Total Liabilities and Member's Equity	$ 6,486,822	$ 4,213,869

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

($ in thousands)	Years Ended December 31, 2018	2017	2016
Revenues:			
Natural gas	$ 1,444,368	$ 706,866	$ 262,765
Oil	133,786	111,441	67,551
NGL	109,221	77,054	36,833
Commodity derivative (loss) gain	(90,881)	212,046	(86,434)
Total Revenues	1,596,494	1,107,407	280,715
Operating Expenses:			
Lease operating expenses	50,163	35,259	24,061
Gathering, processing and transportation expenses	658,117	341,765	186,300
Production and ad valorem taxes	23,362	14,050	7,623
Exploration expenses	156,450	186,152	269,982
General and administrative expenses	63,794	7,960	7,419
General and administrative expenses – related party	—	38,365	27,580
Acquisition expenses	9,407	—	—
Natural gas and oil depreciation, depletion and amortization	500,773	305,573	229,038
Depreciation and amortization of other assets	3,912	1,905	1,864
Impairment of other property and equipment	—	—	2,222
Total Operating Expenses	1,465,978	931,029	756,089
Income (Loss) from Operations	130,516	176,378	(475,374)
Other (Expense) Income:			
Interest expense, net	(91,197)	(69,062)	(88,159)
Acquisition obligation accretion expense	(1,030)	(4,290)	(10,108)
Change in fair value of embedded derivative	18,865	(19,261)	3,616
(Losses) gains on purchases or exchanges of debt	(62,233)	(114,052)	207,470
Other income	683	1,572	2,001
Total Other (Expense) Income	(134,912)	(205,093)	114,820
Net Loss	$ (4,396)	$ (28,715)	$ (360,554)

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY

($ in thousands)	Years Ended December 31, 2018	2017	2016
Balance, Beginning of Period	$ 2,182,500	$ 2,067,183	$ 588,568
Contributions from Member	1,036,993	132,090	1,839,914
Contribution of debt held by Member	—	11,942	—
Purchase of debt by Member	—	—	(745)
Net loss	(4,396)	(28,715)	(360,554)
Balance, End of Period	$ 3,215,097	$ 2,182,500	$ 2,067,183

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

($ in thousands)	Years Ended December 31, 2018	2017	2016
Cash Flows from Operating Activities:			
Net loss	$ (4,396)	$ (28,715)	$ (360,554)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion and amortization	504,685	307,478	230,902
Impairment of other property and equipment	—	—	2,222
Change in fair value of commodity derivatives	34,138	(188,650)	90,831
Impairment of unproved natural gas and oil properties	153,047	183,885	252,845
Non-cash interest expense	27,271	23,714	84,706
Acquisition obligation accretion expense	1,030	4,290	10,108
Change in fair value of embedded derivative	(18,865)	19,261	(3,616)
Losses (gains) on purchases or exchanges of debt	62,233	114,052	(207,470)
Other	(1,218)	2,766	733
Changes in operating assets and liabilities:			
Increase in accounts receivable and other assets	(274,558)	(95,882)	(32,658)
Increase in accounts payable, liabilities and other	205,366	143,245	24,743
Net Cash Provided by Operating Activities	688,733	485,444	92,792
Cash Flows from Investing Activities:			
Drilling and completion costs	(906,064)	(653,942)	(268,082)
Acquisitions of natural gas and oil properties	(1,409,494)	(429,890)	(428,301)
Proceeds from divestitures of natural gas and oil properties	6,564	79,329	16,664
Reductions in (additions to) deposits on pipeline capacity	—	151,193	(41,811)
Additions to other property and equipment	(1,512)	(257)	(715)
Net Cash Used in Investing Activities	(2,310,506)	(853,567)	(722,245)
Cash Flows from Financing Activities:			
Proceeds from credit facility borrowings	1,525,000	—	—
Repayment of credit facility borrowings	(577,000)	—	—
Proceeds from issuance of long-term debt, net	587,166	1,466,250	—
Repayment of long-term debt	(525,000)	(1,290,264)	(464,649)
Cash paid for debt issuance costs	(11,725)	(18,142)	(15,474)
Cash paid for debt prepayment costs	(52,500)	(70,999)	(667)
Repayment of note payable to third party	—	—	(37,170)
Contributions from Member	567,647	132,000	1,331,719
Net Cash Provided by Financing Activities	1,513,588	218,845	813,759
Net (Decrease) Increase in Cash and Cash Equivalents	(108,185)	(149,278)	184,306
Cash and Cash Equivalents, Beginning of Period	119,215	268,493	84,187
Cash and Cash Equivalents, End of Period	$ 11,030	$ 119,215	$ 268,493

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

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

($ in thousands)	Years Ended December 31, 2018	2017	2016
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest and interest paid in kind	$ 63,583	$ 12,901	$ —
Supplemental disclosures of significant non-cash investing and financing activities:			
Increase (decrease) in accrued capital expenditures	$ 56,740	$ 22,224	$ (24,058)
Contributions from Member	$ 469,346	$ —	$ 508,170
Contribution of debt held by Member	$ —	$ 11,942	$ —
Non-cash consideration from divestiture of natural gas and oil properties	$ —	$ 22,056	$ —

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

1. Basis of Presentation and Significant Accounting Policies

Basis of Presentation and Consolidation

Ascent Resources Utica Holdings, LLC (ARUH), together with its wholly-owned subsidiaries (collectively, 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 consolidated financial statements and notes of the Company were prepared in accordance with United States generally accepted accounting principles (US GAAP), and intercompany accounts and balances have been eliminated. 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).

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 manages 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.

Use of Estimates

The preparation of 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 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 Company is unable to predict future commodity prices, and the volatility of commodity prices results in increased uncertainty inherent in these estimates and assumptions. A prolonged period of depressed commodity prices may have a significant impact on the value and volumetric quantities of the Company's proved reserve portfolio, assuming no other changes to the Company's development plans or costs. The Company cannot predict what reserve revisions may be required in future periods.

Significant Accounting Policies

Cash and Cash Equivalents. The Company considers investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents. The Company maintains its cash in accounts that may not be federally insured beyond certain limits; however, the Company has not experienced any losses in such accounts and believes it is not exposed to any significant credit risk on such accounts.

Accounts Receivable. The Company sells natural gas, oil and NGL to various counterparties and participates with other companies in the drilling, completion and operation of natural gas and oil wells. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts after all attempts to collect the balance are exhausted. Accounts receivable at December 31, 2018 and 2017 were $452.3 million and $187.7 million, respectively, and consist primarily of accrued natural gas, oil and NGL revenue receivables and receivables from joint interest billings to owners of properties the Company operates. All accounts receivable are considered to be fully collectible; therefore, no allowance for doubtful accounts is recorded on the consolidated financial statements.

Natural Gas and Oil Properties. The Company uses the successful efforts method of accounting for natural gas and oil properties, whereby costs incurred to acquire interests in properties, to drill and equip exploratory wells that find proved reserves and to drill and equip development wells are capitalized. Drilling and leasehold costs are initially capitalized, but charged to expense if and when the Company determines that the well does not contain proved reserves in commercially viable quantities. If proved reserves are found, the associated capitalized costs become part of proved natural gas and oil properties; however, if proved reserves are not found, the capitalized costs associated with the well are expensed as exploration costs, net of any salvage value. Exploration costs, such as most geological and geophysical costs, are expensed as incurred. Acquisition costs of unproved properties are transferred to proved properties to the extent the costs are associated with successful exploration activities.

Proved natural gas and oil properties are reviewed for impairment whenever events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties. The estimated undiscounted future cash flows expected are compared to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the carrying amount of the properties is reduced to its estimated fair value (typically determined using discounted future cash flows). No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2018, 2017 or 2016. The Company cannot predict whether impairment charges may be required in the future as commodity prices of natural gas, oil and NGL have a significant impact on determining future impairments.

Unproved natural gas and oil properties primarily consist of undeveloped leasehold costs. Individually significant unproved properties, if any, are assessed for impairment on a property-by-property basis and, if the assessment indicates an impairment, a loss is recognized. For individually insignificant unproved properties, impairment losses are recognized by amortizing to exploration expense the portion of the properties' costs that management estimates will not be transferred to proved properties over the remaining lease term. The Company's impairment assessments are affected by economic factors such as the results of exploration activities, commodity price outlooks, anticipated drilling programs, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2018, 2017 and 2016, the Company recorded impairments of $153.0 million, $183.9 million and $252.8 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

Natural Gas and Oil Depreciation, Depletion and Amortization. Natural gas and oil depreciation, depletion and amortization (DD&A) of capitalized drilling and completion costs of producing natural gas and oil properties is computed using the unit-of-production method, based on total estimated proved developed natural gas, oil and NGL reserves. Costs of acquiring proved properties, including leasehold acquisition costs and capitalized interest transferred from unproved properties, are depleted using the unit-of-production method based on total estimated proved natural gas, oil and NGL reserves.

Other Property and Equipment. Other property and equipment is recorded at cost. Upon retirement or disposition of assets, the cost and related accumulated depreciation are removed from the balance sheet with the resulting gain or loss, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight-line method over the estimated useful lives of the related assets generally ranging from two to seven years. The field office location is depreciated using the straight-line method over the estimated useful life of 39 years. Depreciation expense for other property and equipment was $3.9 million for the year ended December 31, 2018 and $1.9 million for the years ended December 31, 2017 and 2016. During the year ended December 31, 2016, the Company recorded a $2.2 million impairment associated with pipeline and gathering assets determined to no longer be in service and deemed obsolete.

Business Combinations. The Company accounts for all business combinations using the acquisition method, which involves the use of significant judgment. In a business combination, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. Any excess or shortage of amounts assigned to assets and liabilities over or under the purchase price is recorded as a gain on bargain purchase or goodwill.

The Company estimates the fair values of assets acquired and liabilities assumed in a business combination using various assumptions (all of which are Level 3 inputs within the fair value hierarchy). The most significant assumptions typically relate to the estimated fair values assigned to proved and unproved natural gas and oil properties. To estimate the fair values of the proved and unproved natural gas and oil properties, the Company develops estimates of natural gas, oil and NGL reserves. Estimates of reserves are based on the quantities of natural gas, oil and NGL that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. Additionally, a risk factor is applied to reserves by reserve type based on industry standards. The Company estimates future prices to apply to the estimated net quantities of reserves based on the applicable ownership percentage acquired and estimates future operating and development costs to arrive at estimates of future net cash flows. The future net cash flows are discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition.

Asset Acquisitions. As part of the Company's business strategy, it periodically pursues the acquisition of natural gas and oil properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The Company's most significant estimates in its allocation typically relate to the value assigned to future recoverable natural gas, oil and NGL reserves and unproved natural gas and oil properties.

Asset Retirement Obligations. The Company recognizes liabilities for obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the assets. The Company recognizes the fair value of a retirement obligation in the period in which the obligation is incurred. For natural gas and oil properties, this is the period in which a natural gas or oil well is acquired or drilled. The liability is then accreted to its present value each period, until it is settled or the well is sold, at which time the liability is removed. The related asset retirement cost is capitalized as part of the carrying amount of the Company's natural gas and oil properties and expensed through depletion of the asset. The accretion expense is recorded as a component of DD&A in the Company's consolidated statements of operations.

Capitalized Interest. The Company capitalizes interest on expenditures made in connection with exploration and development projects, which include developing and constructing assets that have not yet commenced production and investments in unproved natural gas and oil properties. Capitalized interest is determined by multiplying the Company's weighted average interest rate, based on the Company's outstanding borrowings, by the average amount of qualifying costs incurred. Capitalized interest is depreciated over the useful lives of the assets in the same manner as the depreciation of the underlying asset.

Debt Issuance Costs. Debt issuance costs associated with the Company's term debt have been presented as a reduction to long-term debt on the consolidated balance sheets. The Company amortizes debt issuance costs related to the Convertible Notes, 2022 Notes and 2026 Notes through the maturity date using the effective interest method. The amortization of debt issuance costs is recorded in interest expense on the consolidated statements of operations.

Debt issuance costs associated with the Credit Facility have been presented as other long-term assets on the consolidated balance sheets. The Company amortizes debt issuance costs related to the Credit Facility over the scheduled maturity period of the facility on a straight-line basis, which approximates the effective interest method. The amortization of debt issuance costs associated with the Credit Facility is recorded in interest expense on the consolidated statements of operations.

Revenue Recognition. Revenue from the sale of natural gas, oil and NGL is recognized when production is sold to a customer at a fixed or determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. The Company recognizes revenues from the sale of natural gas, oil and NGL based on the Company's share of volumes sold. The Company adopted ASU 2014-09, ASC 606 (as defined below) with an effective date as of January 1, 2018 using the modified retrospective transition approach. See Note 2 for further discussion of the Company's implementation of ASC 606.

Major Customers. 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 customers that constitute 10% or more of the Company's revenues, before the effects of derivatives, for the periods indicated:

	Years Ended December 31,		
	2018	**2017**	**2016**
Tenaska Marketing Ventures	23%	25%	47%
Sequent Energy Management, L.P.	16%	24%	—
Marathon Petroleum Company, L.P.	—	—	16%

The Company does not believe the loss of any single customer 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.

Fair Value of Financial Instruments. Certain financial instruments are reported at fair value on the consolidated balance sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, (i.e., an exit price). To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the asset or liability and have the lowest priority.

The valuation techniques that may be used to measure fair value include a market approach, an income approach and a cost approach. A market approach uses prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities. An income approach uses valuation techniques to convert future amounts to a single present amount based on current market expectations, including present value techniques, option-pricing models and the excess earnings method. The cost approach is based on the amount that currently would be required to replace the service capacity of an asset (replacement cost).

The carrying values of financial instruments comprising cash and cash equivalents, accounts payable and accounts receivable approximate fair values due to the short-term maturities of these instruments.

Equity-Based Compensation. 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.

Certain of the incentive units are accounted for as equity-classified awards in accordance with ASC 718 *Stock Compensation*. Equity-classified awards are measured on the grant date at fair value and compensation cost is recognized over the requisite service period on a straight-line basis. Certain other incentive units are accounted for in accordance with ASC 710 *Compensation.* Compensation for these awards will only be accrued once payment is probable. The Company had immaterial amounts of expense associated with the incentive units in 2018, 2017 and 2016, which is included in the consolidated statements of operations in general and administrative expenses.

Derivatives. The Company periodically enters into commodity derivative instruments to reduce its exposure to fluctuations in future commodity prices and to protect its expected operating cash flow against significant market movements or volatility. All commodity derivative instruments are recognized at their current fair value as either assets or liabilities on the 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 it determines are creditworthy. The creditworthiness of its counterparties is subject to periodic review.

Derivative instruments reflected as current on the consolidated balance sheets represent the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices or rates as of the respective balance sheet dates. Cash settlements of the Company's derivative instruments are generally classified as operating cash flows unless the derivatives are deemed to contain, for accounting purposes, a significant financing element at contract inception, in which case these cash settlements are classified as financing cash flows in the accompanying consolidated statements of cash flows. All of the Company's derivative instruments are subject to International Swaps and Derivatives Association (ISDA) master netting arrangements by contract type which provide for the offsetting of asset and liability positions within each contract type, by counterparty. ISDA master agreements also provide for net settlement over the term of the contract and in the event of default or termination of the contract. The Company nets the value of its derivative instruments by contract type with the same counterparty in the accompanying consolidated balance sheets.

The Company has established the fair value of its derivative instruments using established index prices, volatility curves and discount factors. These estimates are compared to the Company's counterparty values for reasonableness. The values the Company reports in its financial statements are as of a point in time and subsequently change as these estimates are revised to reflect actual results, changes in market conditions and other factors. Derivative transactions are subject to the risk that counterparties will be unable to meet their obligations and are also subject to the risk of the Company's non-performance. This non-performance risk is considered in the valuation of the Company's derivative instruments, but to date has not had a material impact on the values of its derivatives. See Note 6 for further discussion of the Company's derivative instruments.

Commitments and Contingencies. Liabilities for loss contingencies arising from claims, assessments, litigation or other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Liabilities for environmental remediation or restoration claims resulting from allegations of improper operation of assets are recorded when it is probable that obligations have been incurred and the amounts can be reasonably estimated. Expenditures related to such environmental matters are expensed or capitalized in accordance with the Company's accounting policy for property and equipment.

Income Taxes. The Company is treated as a disregarded entity by the Parent for income tax purposes. The Parent is treated as a partnership for income tax purposes, with each partner being separately taxed on their share of income. As such, no income taxes are shown on the Company's consolidated financial statements.

Reclassifications

Certain reclassifications have been made to the Company's 2017 and 2016 consolidated financial statements to conform to the presentation used for the 2018 consolidated financial statements.

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. These amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019 for both public and non-public entities. The amended 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 June 2018, the FASB issued ASU 2018-07, *Compensation - Stock Compensation (Topic 718): Improvements to Nonemployee Share-Based Payment Accounting.* ASU 2018-07 expands the scope of Topic 718 to include share-based payment transactions for acquiring goods and services from nonemployees, and is intended to align the accounting for such payments to nonemployees with the existing requirements for share-based payments granted to employees by clarifying and improving the areas of the overall measurement objective, measurement date, and awards with performance conditions. The amendments in this ASU are effective for public business entities for fiscal years beginning after December 15, 2018, including interim periods within that fiscal year. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, but no earlier than an entity's adoption of Topic 606. The adoption of this guidance is not expected to have a material impact on the Company's financial statements.

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 lease 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 May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASC 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 also results in enhanced revenue disclosures, provides guidance for transactions that were not previously addressed comprehensively and improves guidance for multiple-element arrangements. ASC 606 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. The Company adopted ASC 606 as of January 1, 2018 applying the modified retrospective transition method to contracts that were not completed as of that date. Results for reporting periods beginning after January 1, 2018 are presented under the new revenue standard. Under the modified retrospective method, no adjustments were required as a result of adopting the new revenue standard. The comparative information has not been restated and continues to be reported under the previous revenue standard. See Note 2 for further discussion of the Company's adoption of ASC 606.

Subsequent Events

The Company evaluated its December 31, 2018 consolidated financial statements for subsequent events through March 8, 2019, the date the consolidated financial statements were available to be issued, and such events are noted within.

2. Revenue from Contracts with Customers

Impact of ASC 606 Adoption

Effective January 1, 2018, the Company adopted ASC 606 using the modified retrospective method, which applies to contracts that were not completed as of that date. ASC 606 supersedes previous revenue recognition requirements in ASC 605 *Revenue Recognition* (ASC 605) and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration in exchange for those goods or services. The adoption had no impact on the Company's revenue recognition, including presentation of revenues and expenses, or its financial position, results of operations, net income or cash flows. For periods through December 31, 2017, the Company accounted for its revenue using ASC 605.

Natural Gas, Oil and NGL Revenues

The Company's revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGL that are extracted from the Company's natural gas. Sales of natural gas, oil and NGL are recognized when production is sold to a customer at a fixed or determinable price, delivery has occurred, control has transferred and collection of the revenue is probable. The Company generally considers the delivery of each unit (mmbtu, bbl or gallon) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to (i) whether the purchaser can direct the use of the product, (ii) the transfer of significant risks, (iii) the Company's right to payment and (iv) transfer of legal title.

Revenue is measured based on consideration specified in the contract with the customer and excludes any amounts collected on behalf of third parties. These contracts typically include variable consideration that is based on pricing tied to market indices and volumes delivered in the current month. As such, this market pricing may be constrained (i.e., not estimable) at the inception of the contract but will be recognized based on the applicable market pricing, which will be known upon transfer of the goods to the customer. The payment date is within 30 days of the end of the calendar month in which the commodity is delivered.

Under the Company's natural gas sales contracts, it delivers natural gas to the customer at an agreed upon delivery point. Natural gas is transported from the wellhead to delivery points specified under sales contracts. To deliver natural gas to these points, third parties gather, compress, process and transport the Company's natural gas. The Company's sales contracts provide that the Company generally receives a specific index price adjusted for pricing differentials. The Company transfers control of the product to the customer at the delivery point and recognizes revenue based on the contract price. The costs incurred to gather, compress, process and transport the natural gas prior to the point when control is transferred to the customer are recorded on the consolidated statements of operations as gathering, processing and transportation expenses.

NGL, which are extracted from natural gas through processing, are either sold by the Company directly or to the processor under processing contracts. For NGL sold by the Company directly, the sales contracts provide that the product is delivered to the customer at an agreed upon delivery point and that the Company generally receives a specific index price adjusted for pricing differentials. The Company transfers control of the product to the customer at the delivery point and recognizes revenue based on the contract price. The costs to process and transport NGL to the delivery points are recorded on the consolidated statements of operations as gathering, processing and transportation expenses. For NGL sold to the processor, control is transferred by the Company to the processor at the tailgate of the processing plant, and revenue is recognized based on the price received from the processor.

Under the Company's oil sales contracts, oil is sold to the customer from storage tanks near the wellhead, and the Company collects a contractually agreed upon index price, net of pricing differentials. The Company transfers control of the product from the storage tanks to the customer and recognizes revenue based on the contract price.

The recognition of gains or losses on derivative instruments is not considered revenue from contracts with customers subject to ASC 606.

The Company has elected to exclude from the measurement of the transaction price all taxes assessed by governmental authorities that are both imposed on and concurrent with a specific revenue-producing transaction and collected by the Company from a customer.

Disaggregation of Revenue

The Company's revenues are comprised solely of revenues from customers and include the sale of natural gas, oil and NGL. The Company believes that the disaggregation of revenue into these three major product types appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on the Company's single geographic location. Revenue on the Company's financial statements is disaggregated into revenues from its major product types, and therefore, the adoption of ASC 606 did not result in any change in the presentation of revenue on the Company's financial statements.

Transaction Price Allocated to Remaining Performance Obligations

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient option in ASC 606 which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under the Company's sales contracts, each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required.

Certain of the Company's product sales are short-term in nature, generally through evergreen contracts with terms of one year or less. These contracts typically automatically renew under the same provisions. For these contracts, the Company has utilized the practical expedient option in ASC 606 which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Contract Balances

Under the Company's sales contracts, customers are invoiced after the Company's performance obligations have been satisfied, generally when control of the product has been transferred to the customer, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606. At December 31, 2018 and 2017, receivables from contracts with customers were $401.8 million and $146.8 million, respectively, and were reported in accounts receivable - natural gas, oil and NGL sales on the consolidated balance sheet.

Prior Period Performance Obligations

The Company records revenue in the month production is delivered to the customer. However, settlement statements for certain natural gas and NGL sales may be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the customer and the price that will be received for the sale of the product. The differences between the estimates and the actual amounts for product sales are recorded in the month that payment is received from the customer. For the year ended December 31, 2018, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

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 $766.1 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 $6.9 million, consisting primarily of legal services, due diligence expenses and filing fees, which are presented as acquisition expenses on the 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* (ASC 805). 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	$	766,094
Assets acquired:		
Proved natural gas and oil properties	$	404,086
Unproved natural gas and oil properties		365,891
Accounts receivable – joint interest and other		2,408
Liabilities assumed:		
Revenue payable		(5,002)
Other current liabilities		(949)
Asset retirement obligations		(340)
Fair Value of Net Assets Acquired	$	766,094

The following table presents the revenues and net income contributed by the assets acquired in the CNX and Hess Acquisition on the Company's consolidated statements of operations for the period from August 30, 2018 to December 31, 2018:

($ in thousands)		Period from August 30, 2018 to December 31, 2018
Revenues	$	86,162
Net income	$	36,408

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 properties and associated derivative 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 $501.7 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 $2.5 million, consisting primarily of legal services and filing fees, which are presented as acquisition expenses on the 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 ASC 805. 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	$ 263,151
Equity issued directly from Parent	238,560
Total Consideration	$ 501,711
Assets acquired:	
Proved natural gas and oil properties	$ 270,580
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	$ 501,711

The following table presents the revenues and net income contributed by the assets acquired in the UMD Acquisition on the Company's consolidated statements of operations for the period from July 13, 2018 to December 31, 2018:

($ in thousands)	Period from July 13, 2018 to December 31, 2018
Revenues	$ 70,625
Net income	$ 27,967

Pro Forma Information (Unaudited). The following unaudited pro forma combined financial information presents the Company's results as though the CNX and Hess Acquisition and the UMD Acquisition had both been completed on January 1, 2017. The pro forma combined financial information has been included for comparative purposes and is not necessarily indicative of the results that might have actually occurred had the CNX and Hess Acquisition and UMD Acquisition taken place on January 1, 2017; furthermore, the financial information is not intended to be a projection of future results.

	Years Ended December 31,	
($ in thousands)	2018	2017
Pro forma revenues	$ 1,748,113	$ 1,361,356
Pro forma net income	$ 87,132	$ 107,599

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. In September 2018, Carried Costs reached the 105.0% ceiling, with the buyer having paid $34.7 million of the Carried Costs, and the Company began paying 90.0% of the buyer's remaining development costs. As of December 31, 2018, the Company had paid $20.3 million of the buyer's 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:

	December 31,	
($ in thousands)	2018	2017
Proved natural gas and oil properties	$ 5,457,911	$ 3,322,876
Unproved natural gas and oil properties	1,609,036	1,118,736
Other property and equipment	27,454	19,625
Total Property and Equipment	7,094,401	4,461,237
Accumulated depreciation, depletion and amortization	(1,185,772)	(678,274)
Property and Equipment, net	$ 5,908,629	$ 3,782,963

At December 31, 2018 and 2017, the Company did not have any capitalized well costs associated with exploratory wells that were pending determination of proved reserves.

The Company's asset retirement obligations relate to future plugging and abandonment costs on its natural gas and oil properties and are included in other long-term liabilities on the consolidated balance sheets. As of December 31, 2018 and 2017, the associated liabilities were $1.7 million and $0.6 million, respectively.

5. Long-Term Debt

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

($ in thousands)	December 31, 2018	December 31, 2017
Senior notes due 2022[a]	$ 975,000	$ 1,500,000
Senior notes due 2026[b]	600,000	—
Credit Facility[c]	948,000	—
Convertible notes due 2021[d]	74,116	69,802
Embedded derivative	5,026	23,891
Net unamortized debt issuance costs	(4,243)	(3,087)
Net unamortized debt discounts	(15,079)	(25,832)
Total Long-Term Debt, net	$ 2,582,820	$ 1,564,774

(a) The interest rate was 10.00% as of December 31, 2018 and 2017.
(b) The interest rate was 7.00% as of December 31, 2018.
(c) The interest rate was 4.36% as of December 31, 2018.
(d) The interest rate was 6.50% and 5.50% as of December 31, 2018 and 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 from the issuance of the 2022 Notes 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 December 31, 2018.

In October 2018, the Company issued $600.0 million in aggregate principal amount of senior unsecured notes (2026 Notes) in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. 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 $577.5 million of the $587.2 million net proceeds 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. The Company also paid $1.5 million of accrued and unpaid interest up to, but excluding, the date of the Redemption and used the remaining net proceeds to repay borrowings under the Credit Facility. The Company incurred a loss of $62.2 million in October 2018 related to the Redemption. The Company's obligations under the 2026 Notes are fully and unconditionally guaranteed, jointly and severally, by any current and future material subsidiaries of the Company. The 2026 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 December 31, 2018.

At any time prior to November 1, 2021, the Company may redeem up to 40% of the aggregate principal amount of the 2026 Notes at a price equal to 107% of the principal amount, plus accrued and unpaid interest up to, but excluding, the redemption date, with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Additionally, at any time prior to April 1, 2020 for the 2022 Notes or November 1, 2021 for the 2026 Notes (together, the Senior Notes), the Company may redeem some or all of the Senior Notes, respectively, subject to a make-whole premium plus accrued and unpaid interest up to, but excluding, the redemption date. The Company may redeem some or all of the Senior Notes at the applicable redemption prices (expressed as percentages of principal amount) set forth in the table below on the dates set forth therein:

Senior Notes	Redemption on or after	Redemption Price
2022 Notes	April 1, 2020	107.500%
2022 Notes	April 1, 2021	105.000%
2022 Notes	October 1, 2021 and thereafter	100.000%
2026 Notes	November 1, 2021	103.500%
2026 Notes	November 1, 2022	102.333%
2026 Notes	November 1, 2023	101.167%
2026 Notes	November 1, 2024 and thereafter	100.000%

The Company is not prohibited from acquiring the Senior 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 applicable indenture. Upon the occurrence of a qualifying change of control, the Company is required to offer to repurchase all or any part of the Senior Notes at a purchase price in cash equal to 101% of the aggregate principal amount of the Senior Notes to be repurchased, plus accrued and unpaid interest up 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 Senior 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 Senior Notes will rank senior in right of payment to all of its future subordinated debt. The Senior 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 United States Securities and Exchange Commission (SEC) 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 November 2016, the Company received equity contributions from the Parent of approximately $654.5 million. These equity contributions, combined with previously received equity contributions, surpassed a defined Additional Equity Contribution threshold within the Second Lien Term Loans' credit agreement, which resulted in the interest rate decreasing to 9.5% plus the greater of 1.5% or the 3-month London Interbank Offered Rate (LIBOR). Additionally, the Company no longer had the ability to elect to pay up to 2.0% of interest in kind. Previously, the Second Lien Term Loans bore interest at a rate of 11.5% plus the greater of 1.5% or the 3-month LIBOR with the option to elect to pay up to 2.0%, on a per annum basis, of interest in kind, which was compounded and added to the unpaid principal amount of the loan.

In April 2017, the outstanding $1.290 billion in principal of the Second Lien Term Loans was repaid 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 year ended December 31, 2017, including the write-off of unamortized debt issuance costs and discounts.

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, August and December of 2018, which, in aggregate, increased the borrowing base from $925.0 million to a fully committed $2.0 billion, decreased the sublimit for letters of credit from $647.5 million to $500.0 million, decreased the applicable interest margins by 1.25% and increased the aggregate maximum credit amount from $1.5 billion to $2.5 billion. 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 December 31, 2018, the Company had borrowings of $948.0 million and $370.6 million of letters of credit outstanding under the Credit Facility. As of March 7, 2019, the Company had borrowings of $915.0 million and $330.6 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 0.50% to 1.50% per annum. Eurodollar loans bear interest at a rate per annum equal to LIBOR plus an applicable margin ranging from 1.50% to 2.50% per annum. Due to the weighted average 1-month LIBOR being 2.36% for the applicable interest periods on the most recent election dates, the Company was subject to a weighted average rate of 4.36% per annum as of December 31, 2018. The Company may repay any amounts borrowed prior to the maturity date without any premium or penalty.

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 1.50% to 2.50% per annum, in accordance with the balance of outstanding letters of credit issued. The Company is also subject to a letter of credit 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 years ended December 31, 2018 and 2017, the Company incurred $22.3 million and $14.4 million, respectively, in commitment, participation and fronting fees on letters of credit outstanding and $18.8 million in interest on principal borrowings under the Credit Facility during the year ended December 31, 2018, which is presented as interest expense on the 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 December 31, 2018, the Company was in compliance with the financial covenants of the Credit Facility.

As of December 31, 2018, the Company had $16.5 million in unamortized debt issuance costs associated with the Credit Facility, which are presented as other long-term assets on the consolidated balance sheets.

Convertible Notes

In 2014, the Company issued $1.0 billion of convertible notes due 2021 (Convertible Notes). Through multiple transactions from 2015 through 2017, the Company repurchased or otherwise retired $950.3 million in aggregate principal and accrued and unpaid interest of the Convertible Notes, including $11.1 million of outstanding principal and accrued and unpaid interest in March 2017 contributed to the Company by the Member.

As of December 31, 2018, the Company had $74.1 million in aggregate principal, including accrued and unpaid interest, outstanding of the Convertible Notes. The Convertible Notes are subordinate to the Senior Notes, which rank senior in right of payment, and mature 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 is currently payable at an annual rate of 6.50%. 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, plus accrued and unpaid interest up to, but not including, the maturity date. The Company accretes the 53.8% premium 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 initial public offering (Qualified PO) is at the option of the noteholders. 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. Following the closing of a Qualified PO, the Company will have the option to redeem all of the Convertible Notes that were not otherwise 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 price, including a premium, of 153.8% of the principal amount of the Convertible Notes, plus accrued and unpaid interest up to, but not including, the date of redemption. The Convertible Notes are not redeemable by the holders prior to a change of control or the closing of a Qualified PO.

The principal amount of debt maturities for the five years ended after December 31, 2018 and thereafter are as follows:

($ in thousands)	Principal Amount of Debt Securities
2019	$ —
2020	—
2021[a]	1,078,921
2022	975,000
2023	—
Thereafter	600,000
Total	$ 2,653,921

(a) The Convertible Notes due in 2021 include a premium of $45.8 million and future paid in kind interest of $12.6 million that are both payable upon maturity. The premium is accreted over the scheduled maturity period of the debt.

Interest Expense

Interest expense was comprised of the following:

($ in thousands)	Years Ended December 31, 2018	2017	2016
Interest expense[a]	$ 196,221	$ 169,705	$ 272,357
Long-term debt accretion expense	14,665	12,549	24,505
Deferred debt issuance cost amortization	6,717	9,081	14,947
Capitalized interest	(126,406)	(122,273)	(223,650)
Total Interest Expense, net	$ 91,197	$ 69,062	$ 88,159

(a) Interest expense includes interest paid in kind of $4.3 million, $3.5 million and $107.7 million for the years ended December 31, 2018, 2017 and 2016, respectively.

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. As of December 31, 2018, the Company's natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*. The Company receives a fixed price for its natural gas, oil or NGL production and pays a variable market price to the counterparty.
- *Call Options*. The Company sells call options in exchange for a premium, which establish the maximum price the Company will receive for contracted commodity volumes. At the time of settlement, if the market price exceeds the fixed price of the call option, the Company pays the difference to the counterparty. From time to time, the Company may sell future call options to obtain more favorable strike prices on swap or collar contracts.
- *Collars*. These instruments contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price, the Company pays the difference between market price and the strike price of the sold call to the counterparty. If the market price falls below the put strike price, the Company receives the difference between the market price and the strike price of the purchased put from the counterparty. If the market price is between the put and the call strike prices, no payments are due to or from either party.
- *Three-Way Collars*. Three-way collars consist of a traditional collar and the sale by the Company of an additional put option in exchange for more favorable strike prices on purchased put or sold call options.
- *Basis Swaps*. 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, Dominion South, TCO and Tetco M-2. Under these instruments, the Company receives the fixed price differential and pays the floating market price differential to the counterparty for the contracted volumes.

All commodity derivative instruments are recognized at their current fair value as either assets or liabilities on the consolidated balance sheets. Changes in the fair value of these commodity derivative instruments are recorded in earnings as the Company has not elected hedge accounting for any of its commodity derivative instruments. 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 December 31, 2018, the contracted weighted average natural gas prices and the estimated fair values:

		Weighted Average Prices ($/mmbtu)				
	Average Volume (mmbtu/d)	Fixed Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ 53,038
2019	1,712,500	$ 2.86				
2020	1,340,000	$ 2.74				
2021	410,000	$ 2.73				
Collars:						5,035
2019	15,000		$ 3.40	$ 2.75		
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						203
2021	205,000		$ 2.91	$ 2.50	$ 2.00	
2022	70,000		$ 3.00	$ 2.50	$ 2.00	
Call options:						(54,670)
2019	70,500		$ 3.00			
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	170,000		$ 3.00			
2023	170,000		$ 3.00			
Basis swaps:						8,880
2019	430,000	$ (0.23)				
2020	220,000	$ (0.45)				
Total Estimated Fair Value						$ 12,486

The following table sets forth the average volumes per day associated with the Company's outstanding oil derivative instruments as of December 31, 2018, the contracted weighted average oil prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
Oil:				
Swaps:				$ 46,847
2019	7,200	$ 56.26		
2020	7,500	$ 57.20		
2021	1,000	$ 60.06		
Call options:				(4,819)
2019	2,000		$ 70.00	
2020	4,750		$ 70.00	
2021	3,500		$ 70.00	
Total Estimated Fair Value				$ 42,028

The following table sets forth the average volumes per day associated with the Company's outstanding NGL derivative instruments as of December 31, 2018, the contracted weighted average NGL prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Swap Fixed Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 14,868
2019	2,600	$ 38.55		
2020	1,000	$ 35.07		
Call options - Propane:				(1,027)
2019	1,600		$ 33.60	
2020	3,150		$ 33.60	
Swaps - Ethane:				1,083
2019	750	$ 17.01		
Total Estimated Fair Value				$ 14,924

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

($ in thousands)	Consolidated Balance Sheet Classification	December 31, 2018 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	$ 117,732	$ (65,328)	$ 52,404
Natural gas, oil and NGL commodity derivatives	Long-term derivative assets	$ 150,349	$ (110,806)	$ 39,543
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative liabilities	$ (66,396)	$ 65,328	$ (1,068)
Natural gas, oil and NGL commodity derivatives	Long-term derivative liabilities	$ (132,247)	$ 110,806	$ (21,441)

($ in thousands)	Consolidated Balance Sheet Classification	December 31, 2017 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 consolidated statements of operations for the periods presented:

($ in thousands)	Consolidated Statements of Operations Presentation	Years Ended December 31, 2018	2017	2016
Natural gas, oil and NGL commodity derivatives	Commodity derivative (loss) gain	$ (90,881)	$ 212,046	$ (86,434)

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 December 31, 2018 and 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 regarding the Company's commodity derivative instruments.

	Fair value measurements at December 31, 2018 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 91,947	$ —	$ 91,947
Total	$ —	$ 91,947	$ —	$ 91,947
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 22,509	$ —	$ 22,509
Embedded derivative[a]	—	—	5,026	5,026
Total	$ —	$ 22,509	$ 5,026	$ 27,535

[a] This is presented as long-term debt on the consolidated balance sheet as of December 31, 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 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:

	December 31, 2018	December 31, 2017
Estimated price of Convertible Notes’ principal value	137.25%	98.0%
Probability of Qualified PO or change of control	10% - 35% with a total of 70% 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	13.8%	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 consolidated balance sheets and as a Level 3 measurement:

($ in thousands)	Years Ended December 31, 2018	Years Ended December 31, 2017
Balance, beginning of period	$ 23,891	$ 5,403
Change due to purchases or exchanges of debt	—	(773)
Change in fair value[(a)]	(18,865)	19,261
Balance, end of period	$ 5,026	$ 23,891

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

Fair Value of Debt

The carrying amounts and estimated fair values of long-term debt as of December 31, 2018 and 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 the Company’s long-term debt.

($ in thousands)	December 31, 2018 Carrying Value	December 31, 2018 Fair Value	December 31, 2017 Carrying Value	December 31, 2017 Fair Value
2022 Notes	$ 957,993	$ 997,230	$ 1,467,465	$ 1,608,750
2026 Notes	584,876	540,000	—	—
Credit Facility	948,000	948,000	—	—
Convertible Notes	86,925	99,567	73,418	67,175
Total	$ 2,577,794	$ 2,584,797	$ 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 years ended December 31, 2017 and 2016, the Company incurred expenses of approximately $57.9 million and $43.0 million for the services performed under the Ascent MSA, of which $21.5 million and $14.8 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 are presented below for the periods indicated:

($ in thousands)	Consolidated Statements of Operations Presentation	Years Ended December 31, 2018	2017	2016
Blue Racer Midstream, LLC[(a)]	GP&T expenses	$ (47,355)	$ (22,762)	$ (25,090)
Blue Racer Midstream, LLC[(a)]	NGL revenues	$ 28,726	$ 3,499	$ 8,569
Crestwood Services, LLC[(b)]	NGL revenues	$ 47,523	$ —	$ —
Jefferson Gas Gathering Company, LLC[(c)]	GP&T expenses	$ (86,898)	$ (34,887)	$ (5,535)
MarkWest Utica EMG, LLC[(d)]	GP&T expenses	$ (26,535)	$ (25,693)	$ (16,742)
MarkWest Utica EMG, LLC[(d)]	NGL revenues	$ 32,375	$ 63,800	$ 24,543
Ohio Gathering Company, LLC[(d)]	GP&T expenses	$ (36,398)	$ (30,543)	$ (17,981)
Ohio River System LLC[(e)]	GP&T expenses	$ (45,103)	$ (18,679)	$ (5,185)
Rover Pipeline LLC[(f)]	GP&T expenses	$ (173,826)	$ (25,680)	$ —
Rockies Express Pipeline LLC[(g)]	GP&T expenses	$ (95,112)	$ (91,271)	$ (65,991)

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)	Consolidated Balance Sheets Classification	December 31, 2018	2017
Blue Racer Midstream, LLC[(a)]	Accounts payable	$ (8,304)	$ (1,742)
Blue Racer Midstream, LLC[(a)]	Accounts receivable - natural gas, oil and NGL sales	$ 6,071	$ 155
Crestwood Services, LLC[(b)]	Accounts receivable - natural gas, oil and NGL sales	$ 9,157	$ —
Jefferson Gas Gathering Company, LLC[(c)]	Accounts payable	$ (19,649)	$ (12,777)
MarkWest Utica EMG, LLC[(d)]	Accounts receivable - natural gas, oil and NGL sales	$ 1,439	$ 10,355
Ohio Gathering Company, LLC[(d)]	Accounts payable	$ (16,919)	$ (7,032)
Ohio River System LLC[(e)]	Accounts payable	$ (11,010)	$ (3,240)
Rover Pipeline LLC[(f)]	Accounts payable	$ (20,640)	$ (9,264)
Rockies Express Pipeline LLC[(g)]	Accounts payable	$ (9,366)	$ (9,353)

(a) In August 2014, the Company entered into a gas gathering agreement with Blue Racer Midstream, LLC (BRM), and in October 2017, the Company entered into a capacity utilization agreement with BRM. First Reserve has significant influence over BRM through its equity investments in BRM made in December 2018. Additional gas gathering and processing and NGL sales agreements between BRM and third parties were assigned to the Company in June 2014, February 2017 and August 2018.

(b) 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.

(c) 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.

(d) 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.

(e) 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*.

(f) 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*.

(g) 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, property damage claims, contract actions 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 outside 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.

The Company is defending against certain pending claims, has resolved a number of claims through negotiated settlements and prevailed in various other lawsuits. Based on management's current assessment, the Company believes no pending or threatened lawsuit or dispute relating to the Company's business operations is likely to have a material adverse effect on its 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. For all such pending litigation, as of December 31, 2018, the Company has accrued $9.4 million.

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 December 31, 2018:

($ in thousands)	Pipeline Commitments	Operating Leases	Other Purchase Obligations	Total
2019	$ 612,488	$ 3,711	$ 921	$ 617,120
2020	644,526	3,472	1,091	649,089
2021	661,517	805	1,051	663,373
2022	665,526	—	—	665,526
2023	665,213	—	—	665,213
Thereafter	6,853,425	—	—	6,853,425
Total	$ 10,102,695	$ 7,988	$ 3,063	$ 10,113,746

Pipeline Commitments

The Company has entered into certain pipeline capacity commitments with various counterparties in order to facilitate the delivery of its production to market and reduce the impact of possible production curtailments that may arise due to limited capacity. These contracts commit the Company to transport minimum daily natural gas or NGL volumes at negotiated rates or pay specified fees for any deficiencies. The amounts in the table above represent the gross amounts the Company is committed to pay; however, 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 credit support as defined in each agreement which may, in aggregate, reach $446.9 million. As of December 31, 2018, the Company had issued a $40.0 million letter of credit to ORS, $241.3 million in letters of credit to Rover, $59.5 million in letters of credit to REX and $29.8 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 and $46.8 million in surety bonds to certain other firm transportation providers. In February 2019, the $40.0 million letter of credit to ORS was released and replaced with a surety bond.

Operating Lease Commitments

The Company leases certain equipment and office space. Lease expense related to operating leases totaled $5.0 million, $1.3 million and $0.6 million during the years ended December 31, 2018, 2017 and 2016, respectively. The increase in operating lease expense in 2018 was 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 December 31, 2017, the Company owed $61.1 million 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 consolidated balance sheets. The balance of the joint venture participation agreement became due on September 30, 2018, and the Company satisfied and paid the remaining obligation of $18.8 million in October 2018.

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 oil prices in 2018, the Company recognized a liability of $5.0 million as of December 31, 2018, which was paid in January 2019. 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 December 31, 2018 and 2017:

	December 31,	
($ in thousands)	2018	2017
Drilling and completion accrual	$ 124,484	$ 96,944
Gathering, processing and transportation expense accrual	106,005	55,541
Other	98,091	47,615
Total Other Current Liabilities	$ 328,580	$ 200,100

11. Supplemental Information on Natural Gas, Oil and NGL Producing Activities (Unaudited)

The following disclosures provide supplemental unaudited information regarding the Company's natural gas, oil and NGL activities, which are entirely within the United States:

Capitalized costs related to the Company's natural gas, oil and NGL producing activities are summarized as follows:

$ in thousands	December 31, 2018	December 31, 2017
Proved	$ 5,457,911	$ 3,322,876
Unproved	1,609,036	1,118,736
Total	7,066,947	4,441,612
Accumulated depreciation, depletion and amortization	(1,174,777)	(674,186)
Net Capitalized Costs	$ 5,892,170	$ 3,767,426

Costs incurred in natural gas and oil property acquisition, exploration and development activities are summarized in the table below, including additions to asset retirement obligations of $1.0 million, $0.5 million and a nominal amount for the years ended December 31, 2018, 2017 and 2016, respectively:

$ in thousands	Years Ended December 31, 2018	2017	2016
Acquisition costs of properties:			
Proved properties	$ 675,242	$ 32,261	$ 3,662
Unproved properties	1,146,056	386,789	497,144
Total property acquisition costs	1,821,298	419,050	500,806
Exploration costs	3,404	2,269	17,136
Development costs	953,393	683,616	265,280
Total	$ 2,778,095	$ 1,104,935	$ 783,222

Results of Operations from Natural Gas, Oil and NGL Producing Activities

The results of operations included below consist of revenues and expenses directly associated with the Company's natural gas, oil and NGL producing activities. These do not include any interest expense or indirect general and administrative costs, and therefore, are not necessarily indicative of the net operating results of our natural gas, oil and NGL operations.

$ in thousands	Years Ended December 31, 2018	2017	2016
Revenues, excluding the effects of commodity derivatives	$ 1,687,375	$ 895,361	$ 367,149
Lease operating expenses	(50,163)	(35,259)	(24,061)
Gathering, processing and transportation expenses	(658,117)	(341,765)	(186,300)
Production and ad valorem taxes	(23,362)	(14,050)	(7,623)
Exploration expenses	(156,450)	(186,152)	(269,982)
Natural gas and oil depreciation, depletion and amortization	(500,773)	(305,573)	(229,038)
Results of Operations	$ 298,510	$ 12,562	$ (349,855)

Natural Gas, Oil and NGL Reserves

Proved reserves are estimated volumes of natural gas, oil and NGL that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those reserves expected to be recovered through existing wells, equipment and operating methods. Proved undeveloped reserves include drilling locations that are more than one offset location away from productive wells, reasonably certain of containing proved reserves and scheduled to begin drilling within five years under the Company's development plan. The Company's development plans are subject to uncertainties and variables, including the availability of capital, future natural gas, oil and NGL prices, cash flows from operations, future drilling costs, demand for natural gas, oil and NGL and other economic factors. Net quantities of proved reserves exclude royalties and interests owned by others.

The proved natural gas, oil and NGL reserves for the years ended December 31, 2018, 2017 and 2016 were prepared by the Company's reservoir engineers utilizing analogy to offset production, volumetrics, conventional decline curve analysis and rate transient analysis. Proved reserve estimates for the years ended December 31, 2018, 2017, and 2016 were also independently prepared by Software Integrated Solutions (SIS) (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation. SIS reviewed the Company's type curves for reasonableness and benchmarked them with their own independent analysis from a sampling of the Company's type curves. SIS's results were in reasonable agreement with the Company's results; therefore, they used the Company's type curves as the basis for their reserves projections.

Estimating quantities of proved natural gas, oil and NGL reserves is a complex process that involves significant interpretations and assumptions and cannot be measured in an exact manner. It requires interpretations and judgment of available technical data, including the evaluation of available geological, geophysical, and engineering data and are revised, as warranted by additional performance data. The information provided below related to the Company's natural gas, oil and NGL reserves is presented in accordance with regulations prescribed by the SEC.

Subsequent to December 31, 2018, there have been no major discoveries, favorable or otherwise, that are considered to have caused a significant change in the Company's estimated proved reserves at December 31, 2018. The following table sets forth proved reserves during the periods indicated for the Company:

	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)[(a)]
Proved Reserves at December 31, 2015	1,195,977	26,233	30,025	1,533,529
Extensions, discoveries and other additions	629,197	3,602	2,916	668,304
Revisions	(231,492)	(2,410)	(3,621)	(267,675)
Production	(109,714)	(2,035)	(2,588)	(137,451)
Proved Reserves at December 31, 2016	1,483,968	25,390	26,732	1,796,707
Extensions, discoveries and other additions	2,290,332	7,774	9,100	2,391,578
Revisions	416,389	(5,866)	5,398	413,573
Purchases of reserves	37,173	531	306	42,198
Sales of reserves	(75,036)	(3,172)	(2,743)	(110,526)
Production	(240,980)	(2,492)	(3,286)	(275,653)
Proved Reserves at December 31, 2017	3,911,846	22,165	35,507	4,257,877
Extensions, discoveries and other additions	2,120,130	19,318	39,055	2,470,372
Revisions	255,740	(214)	9,182	309,543
Purchases of reserves	906,504	3,437	24,335	1,073,139
Production	(457,747)	(2,262)	(3,974)	(495,168)
Proved Reserves at December 31, 2018	6,736,473	42,444	104,105	7,615,763
Proved developed reserves:				
December 31, 2016	582,499	11,487	15,015	741,508
December 31, 2017	1,445,354	8,762	14,622	1,585,659
December 31, 2018	2,846,772	16,659	47,046	3,228,997
Proved undeveloped reserves:				
December 31, 2016	901,468	13,903	11,719	1,055,199
December 31, 2017	2,466,492	13,403	20,885	2,672,218
December 31, 2018	3,889,701	25,785	57,059	4,386,766

(a) Oil and NGL are converted to mcfe at the rate of one barrel equals six mcf based upon the approximate relative energy content of oil and NGL to natural gas, which is not necessarily indicative of the relationship of oil and NGL to natural gas prices.

During the year ended December 31, 2018, the Company added approximately 2.470 tcfe in proved reserves through the continued development of its Utica Shale acreage. Revisions of previous estimates included upward revisions of 34.2 bcfe due to higher commodity prices and upward revisions of 275.3 bcfe due to improved drilling and operating efficiencies, including the impact of extended laterals. As of December 31, 2018, all proved undeveloped locations are in accordance with the SEC five year rule. The Company added proved reserves through acquisitions of 1.073 tcfe. The unadjusted 12-month average prices used to calculate reserves at December 31, 2018 were $3.10 per mmbtu for natural gas and $65.56 per barrel for oil and condensate.

During the year ended December 31, 2017, the Company added approximately 2.392 tcfe in proved reserves through the continued development of its Utica Shale acreage. Revisions of previous estimates included upward revisions of 585.5 bcfe due to higher commodity prices, upward revisions of 7.9 bcfe due to improved drilling and operating efficiencies offset by downward revisions of 179.8 bcfe due to removing proved undeveloped reserves where it was determined development would occur outside of the Company's five year development plan. As of December 31, 2017, all proved undeveloped locations were in accordance with the SEC five year rule. The Company added proved reserves through acquisitions of 42.2 bcfe and reduced proved reserves through divestitures of 110.5 bcfe. The unadjusted 12-month average prices used to calculate reserves at December 31, 2017 were $2.98 per mmbtu for natural gas and $51.34 per barrel for oil and condensate.

During the year ended December 31, 2016, the Company added 668.3 bcfe in proved reserves through drilling activities and evaluation of proved areas in the Utica Shale. The Company did not add or reduce significant proved reserves through acquisitions or divestitures. The majority of the downward revisions of 267.7 bcfe relates to negative price revisions of 356.6 bcfe, which more than offset the positive performance revisions of 88.9 bcfe for the existing properties. As of December 31, 2016 all proved undeveloped locations were in accordance with the SEC five year rule. The unadjusted 12-month average prices used to calculate reserves at December 31, 2016 were $2.48 per mmbtu for natural gas and $42.75 per barrel for oil and condensate.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves

ASC 932, *Extractive Activities - Oil and Gas*, prescribes guidelines for computing a standardized measure of future net cash flows and changes therein related to proved reserves. The Company has followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2018, 2017 and 2016 were determined by applying the unweighted arithmetic average of the prices on the first day of each month for the 12 months of the year and year-end costs to the estimated quantities of natural gas, oil and NGL to be produced. Actual future prices and costs may be materially higher or lower than the prices and costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic condition applied for that year. The Company is a disregarded entity by the Parent for income tax purposes, and therefore, it has estimated no future income tax expense. The resulting future net cash flows are reduced to the present value amount by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the FASB and do not necessarily reflect the Company's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following table sets forth the Company's standardized measure of future net cash flows from its proved natural gas, oil and NGL reserves:

	December 31,		
$ in thousands	2018	2017	2016
Future cash inflows	$ 26,284,676	$ 12,671,869	$ 5,157,113
Future production costs	(11,763,838)	(6,349,919)	(2,901,683)
Future development costs	(2,207,600)	(1,451,743)	(595,058)
Future net cash flows	12,313,238	4,870,207	1,660,372
Discount to present value at 10% annual rate	(6,362,658)	(2,573,628)	(804,018)
Standardized Measure of Discounted Future Net Cash Flows	$ 5,950,580	$ 2,296,579	$ 856,354

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas, Oil and NGL Reserves

The following table sets forth the changes in the Company's standardized measure of future net cash flows relating from its proved natural gas, oil and NGL reserves:

	Years Ended December 31,		
$ in thousands	2018	2017	2016
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Period	$ 2,296,579	$ 856,354	$ 901,320
Sales of natural gas, oil and NGL produced, net of production costs	(955,733)	(504,287)	(149,166)
Net changes in prices and production costs	938,280	185,725	(318,823)
Extensions and discoveries, net of production and development costs	2,002,124	1,212,246	274,008
Changes in future development costs	(129,486)	(350,380)	165,369
Development costs incurred during period that reduced future development costs	375,879	116,498	124,389
Revisions of previous quantity estimates	196,707	648,911	(171,887)
Purchase of reserves	816,944	19,278	—
Sales of reserves	—	(77,916)	—
Accretion of discount	229,658	85,635	90,132
Changes in production rates and other	179,628	104,515	(58,988)
Standardized Measure of Discounted Future Net Cash Flows, End of Period	$ 5,950,580	$ 2,296,579	$ 856,354