MANAGEMENT'S DISCUSSION AND ANALYSIS AND
CONSOLIDATED FINANCIAL STATEMENTS

Ascent Resources Utica Holdings, LLC

As of December 31, 2019 and 2018 and for the Years Ended December 31, 2019, 2018 and 2017.

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 the seventh largest producer of natural gas in the United States in terms of daily production and are focused on exploring for, developing, producing and operating natural gas and oil properties in the Utica Shale. We are a wholly-owned subsidiary of Ascent Resources Operating, LLC (our Member) and an indirect wholly-owned subsidiary of Ascent Resources, LLC (our 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 349,000 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 in approximately 77,000 fee mineral acres that provide enhanced value without additional capital costs or operating expenses.

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.

2019 Highlights

- Total proved reserves increased 21% to 9.252 trillion cubic feet equivalent (tcfe) as of December 31, 2019 from 7.616 tcfe as of December 31, 2018, primarily through the drill bit.
- Net income increased by $470.4 million to $466.0 million in 2019 from a net loss of $4.4 million in 2018.
- Net production increased 45% to 719.1 billion cubic feet equivalent (bcfe) in 2019 from 495.2 bcfe in 2018 as a result of our drilling and completion activity and the completion of acquisitions in the third quarter of 2018. Our net daily production in 2019 averaged 1,970 million cubic feet equivalent (mmcfe) per day and was comprised of approximately 89% natural gas, 4% oil and 7% NGL.
- In December, our senior secured revolving credit facility (Credit Facility) agreement was amended, which extended the maturity date to April 1, 2024, reaffirmed the borrowing base at $2.0 billion and reduced the amount authorized for letters of credit to $250.0 million. The maturity date will accelerate to December 30, 2021 if more than $200.0 million of the 2022 Notes are outstanding as of December 30, 2021.

Well Data

As of December 31, 2019, we held an interest in approximately 792 gross (472 net) productive wells, including 710 gross (472 net) properties in which we held a working interest and 82 gross properties in which we only held an overriding or royalty interest. Of the wells in which we had a working interest, 666 gross (448 net) were classified as natural gas productive wells and 44 gross (24 net) were classified as oil productive wells. We operated approximately 523 gross (455 net) of our productive wells in which we had a working interest. During 2019, we drilled 126 gross (112 net) wells as operator, participated in 2 gross wells and held an overriding or royalty interest in another 7 gross wells drilled by other operators. We operated approximately 99% of our net production volumes in 2019.

Drilling Activity

The following table describes the productive wells we operated or participated in during the years ended December 31, 2019, 2018 and 2017:

	Productive Wells Drilled during the Years Ended December 31,					
	2019		2018		2017	
	Gross	Net	Gross	Net	Gross	Net
Development	128	112	110	80	100	76

As of December 31, 2019, we had 64 gross (57 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, 2019, 2018 or 2017.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2019 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, 2019:

Developed Acres		Undeveloped Acres		Total Acres	
Gross	Net[a]	Gross	Net[a][b]	Gross	Net[a]
117,293	107,144	299,897	241,524	417,190	348,668

(a) We also own royalty interests in approximately 77,000 fee mineral acres.

(b) Approximately 56% of our net undeveloped leasehold acreage is not subject to expiration because it is held by production, or it is acreage on which we own the mineral rights.

The following table sets forth the number of total undeveloped acres as of December 31, 2019 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
2020	22,876	19,980
2021	14,450	12,542
2022	40,037	38,795
2023	22,767	21,436
2024 and thereafter	15,678	14,307
Total	115,808	107,060

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, 2019:

	Natural Gas (bbtu)	Ethane (mbbls)
2020	105,978	1,409
2021	104,781	3,229
2022	104,781	3,229
2023	104,781	3,229
2024	62,363	3,238
2025 - 2029	198,637	6,458
Total	681,321	20,792

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

The following table sets forth information regarding our net 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,		
	2019	2018	2017
Net Production Volumes:			
Natural gas (mmcf)	638,243	457,747	240,980
Oil (mbbls)	4,794	2,262	2,492
NGL (mbbls)	8,685	3,974	3,286
Natural Gas Equivalent (mmcfe)	719,113	495,168	275,653
Average Sales Prices:			
Natural gas ($/mcf)	$ 2.49	$ 3.16	$ 2.93
Oil ($/bbl)	$ 50.38	$ 59.15	$ 44.71
NGL ($/bbl)	$ 17.11	$ 27.48	$ 23.45
Natural Gas Equivalent ($/mcfe)	$ 2.75	$ 3.41	$ 3.25
Settlements of commodity derivatives ($/mcfe)	0.27	(0.11)	0.08
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.02	$ 3.30	$ 3.33
Operating Expenses ($/mcfe):			
Lease operating expenses	$ 0.10	$ 0.10	$ 0.13
Gathering, processing and transportation expenses	$ 1.19	$ 1.33	$ 1.24

Natural Gas, Oil and NGL Reserves

All of our estimated reserves are located within the Point Pleasant interval of the Utica Shale. The following table sets forth our proved reserves as of December 31, 2019:

	December 31, 2019			
	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)
Proved developed reserves[(a)]	3,443,414	16,000	61,770	3,910,032
Proved undeveloped reserves	4,702,651	32,259	74,246	5,341,683
Total	8,146,065	48,259	136,016	9,251,715

(a) Approximately 161.0 bcfe, or 4%, of our proved developed reserves were non-producing.

The table below sets forth information as of December 31, 2019, 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, 2019. 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, 2019. The prices used in our reserve reports were $2.58 per mmbtu of natural gas and $55.85 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, 2019. 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, 2019. 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, 2019		
($ in thousands)	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$ 4,425,972	$ 4,194,440	$ 8,620,412
PV-10	$ 2,546,850	$ 1,410,802	$ 3,957,652
Standardized measure[(a)]			$ 3,957,652

(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, 2019, our estimated proved reserves included approximately 5.342 trillion cubic feet equivalent (tcfe) of reserves classified as proved undeveloped, compared to approximately 4.387 tcfe as of December 31, 2018. The table below is a summary of changes in our proved undeveloped reserves (PUDs) for 2019:

	Total (mmcfe)
Proved undeveloped reserves at December 31, 2018	4,386,766
Extensions, discoveries and other additions	2,259,619
Revisions	(513,386)
Purchases of reserves	8
Sales of reserves	(9,247)
Conversions into proved developed reserves	(782,077)
Proved undeveloped reserves at December 31, 2019	5,341,683

As of December 31, 2019, there were no PUDs that had remained undeveloped for five years or more. Our proved undeveloped extensions and discoveries of approximately 2.260 tcfe of reserves resulted from the continued development of our Utica Shale acreage. Revisions of previous estimates included upward revisions of 45.7 bcfe due to improved drilling and operating efficiencies, including the impact from extended laterals, downward revisions of 114.7 bcfe due to lower commodity prices and downward revisions of 444.4

bcfe resulting primarily from removing PUDs where it was determined development would occur outside of our five-year development plan. In 2019, we invested $438.0 million to convert 782.1 bcfe from proved undeveloped reserves to proved developed reserves.

The future net revenues attributable to our estimated PUDs of $4.2 billion as of December 31, 2019, and associated PV-10 of $1.4 billion, have been calculated assuming that we will expend approximately $2.8 billion to develop these reserves over the next five years, 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, 2019 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 U.S. Securities and Exchange Commission (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 22 years of reservoir estimation and operations experience, and our engineering and geoscience staff have an average of approximately 13 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, 2019, 2018, 2017 and 2016 is derived from the audited consolidated financial statements. The financial data included may not be indicative of our future results.

($ in thousands)	Years Ended December 31, 2019	2018	2017
Statements of operations data:			
Revenues:			
Natural gas	$ 1,589,099	$ 1,444,368	$ 706,866
Oil	241,521	133,786	111,441
NGL	148,639	109,221	77,054
Commodity derivative gain (loss)	441,139	(90,881)	212,046
Total Revenues	2,420,398	1,596,494	1,107,407
Operating Expenses:			
Lease operating expenses	72,606	50,163	35,259
Gathering, processing and transportation expenses	856,126	658,117	341,765
Production and ad valorem taxes	34,167	23,362	14,050
Exploration expenses	124,477	156,450	186,152
General and administrative expenses, including related party	61,027	63,794	46,325
Acquisition expenses	—	9,407	—
Natural gas and oil depreciation, depletion and amortization	702,414	500,773	305,573
Depreciation and amortization of other assets	3,239	3,912	1,905
Total Operating Expenses	1,854,056	1,465,978	931,029
Income from Operations	566,342	130,516	176,378
Other (Expense) Income:			
Interest expense, net	(109,114)	(92,227)	(73,352)
Change in fair value of embedded derivative	5,026	18,865	(19,261)
Losses on purchases or exchanges of debt	—	(62,233)	(114,052)
Other income	3,711	683	1,572
Total Other Expense	(100,377)	(134,912)	(205,093)
Net Income (Loss)	$ 465,965	$ (4,396)	$ (28,715)
Balance sheets data (at period end):			
Cash and cash equivalents	$ 7,346	$ 11,030	$ 119,215
Total assets	$ 7,010,418	$ 6,486,822	$ 4,213,869
Total long-term debt, net	$ 2,838,676	$ 2,582,820	$ 1,564,774
Total liabilities	$ 3,329,035	$ 3,271,725	$ 2,031,369
Total liabilities and Member's equity	$ 7,010,418	$ 6,486,822	$ 4,213,869

Liquidity and Capital Resources

Liquidity Overview

Our natural gas, oil and NGL operations, including our exploration, drilling, completions 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, cash flows from operations, draws on our Credit Facility and proceeds from the issuance of debt. Based on existing market conditions and our expected liquidity needs, among other factors, we may use a portion of our cash flows from operations, proceeds from divestitures, securities offerings or Credit Facility borrowings to repay debt prior to scheduled maturities, and may seek opportunities to refinance all or a portion of our senior notes.

As of December 31, 2019, we had a cash balance of $7.3 million and availability under our Credit Facility of $641.5 million. In December 2019, the Credit Facility agreement was amended, which extended the maturity date to April 1, 2024, reaffirmed the borrowing base at $2.0 billion and reduced the amount authorized for letters of credit to $250.0 million. The maturity date will accelerate to December 30, 2021 if more than $200.0 million of the 2022 Notes are outstanding as of December 30, 2021. The next redetermination of our Credit

Facility is expected to occur in April 2020. Based on our expected operating cash flows, Credit Facility availability and cash on hand, we anticipate being able to satisfy all of our financial obligations and commitments for the next twelve months.

Substantial capital expenditures are required to replace reserves as well as sustain 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 an extended 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. In order to partially mitigate our exposure to these price risks, we maintain a hedging program for our natural gas, oil and NGL production. For further discussion of our commodity derivative instruments, see Note 6 of the notes to our consolidated financial statements included in this report.

Sources and Uses of Funds

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

	Years Ended December 31,		
($ in thousands)	**2019**	**2018**	**2017**
Cash provided by operating activities	$ 1,140,118	$ 688,733	$ 485,444
Proceeds from credit facility borrowings, net	240,000	948,000	—
Proceeds from divestitures of natural gas and oil properties	12,474	6,564	79,329
Proceeds from issuance of long-term debt, net	—	587,166	1,466,250
Contributions from Member	—	567,647	132,000
Reductions in deposits on pipeline capacity	—	—	151,193
Total Sources of Cash and Cash Equivalents	$ 1,392,592	$ 2,798,110	$ 2,314,216

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

	Years Ended December 31,		
($ in thousands)	**2019**	**2018**	**2017**
Natural Gas and Oil Expenditures:			
Drilling and completion costs	$ 1,096,627	$ 875,810	$ 639,585
Acquisitions of natural gas and oil properties	163,220	1,313,342	323,341
Interest capitalized[(a)]	123,370	126,406	120,906
Total Natural Gas and Oil Expenditures	1,383,217	2,315,558	1,083,832
Other Uses of Cash and Cash Equivalents:			
Cash paid for debt issuance costs	9,512	11,725	18,142
Additions to other property and equipment	3,547	1,512	257
Repayment of long-term debt	—	525,000	1,290,264
Cash paid for debt prepayment costs	—	52,500	70,999
Total Other	13,059	590,737	1,379,662
Total Uses of Cash and Cash Equivalents	$ 1,396,276	$ 2,906,295	$ 2,463,494

(a) Interest capitalized in 2019 consists of $94.8 million related to unproved leasehold and $28.6 million related to drilling and completions. Interest capitalized in 2018 consists of $96.1 million related to unproved leasehold and $30.3 million related to drilling and completions. Interest capitalized in 2017 consists of $106.5 million related to unproved leasehold and $14.4 million related to drilling and completions.

Net cash flow provided by operating activities was approximately $1.14 billion, $688.7 million and $485.4 million for 2019, 2018 and 2017, respectively. The increase in operating cash flow in 2019 compared to 2018 was primarily the result of increases in the volumes of natural gas, oil and NGL produced, which were partially offset by decreases in our average realized sales price. Our volumes have increased in 2019 compared to 2018 organically through the drill bit and as a result of acquiring natural gas and oil properties from CNX Resources Corporation and Hess Corporation (together, the CNX and Hess Acquisition) and Utica Minerals Development, LLC (the UMD Acquisition, collectively, the 2018 Acquisitions), as discussed in Note 3, *2018 Acquisitions*, of the notes to our consolidated financial statements included in this report. The increase in operating cash flow in 2018 compared to 2017 was primarily the result of increased natural gas production and realized prices year-over-year.

During 2018, we received a net $587.2 million in cash from the issuance of our 2026 Notes (defined below). We used approximately $577.5 million of the net proceeds to fund the Redemption (defined below), and the remaining net proceeds were used to repay borrowings under the Credit Facility. In addition, we received $567.6 million in net cash contributions from equity capital raised by our Parent to partially fund the 2018 Acquisitions.

During 2017, we received a net $1.47 billion in cash from the issuance of the 2022 Notes. The proceeds were used to repay the $1.29 billion of principal of previously outstanding second lien term loans plus accrued and unpaid interest and a prepayment penalty. 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 primarily unproved leasehold in the Utica Shale. We also received $79.3 million in 2017 related to the sale of a partial interest in producing and non-producing natural gas and oil properties. 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.

Our drilling and completion costs were $1.10 billion, $875.8 million and $639.6 million in 2019, 2018 and 2017, respectively. The increase in drilling and completion costs is primarily the result of increased lateral lengths year-over-year, as well as higher working interests in newly completed wells. We drilled 126 new wells in 2019 compared to 102 new wells in 2018 and 88 new wells in 2017.

We spent cash of $163.2 million, $284.0 million and $323.3 million in 2019, 2018 and 2017, respectively, primarily related to the acquisition of leases arising in the ordinary course of business. Additionally, in 2018, we spent cash of $766.1 million to fund the CNX and Hess Acquisition and $263.2 million to fund the UMD Acquisition, which is included in our natural gas and oil property acquisition costs. 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.

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 December 2019, the Credit Facility agreement was further amended, which extended the maturity date to April 1, 2024, reaffirmed the borrowing base at $2.0 billion and reduced the amount authorized for letters of credit to $250.0 million. The maturity date will accelerate to December 30, 2021 if more than $200.0 million of the 2022 Notes are outstanding as of December 30, 2021. As of December 31, 2019, the borrowing base was a fully committed $2.0 billion, and we had $1.2 billion of borrowings outstanding and $170.5 million of letters of credit outstanding under the Credit Facility.

Under the Credit Facility agreement, we may borrow either base rate loans or Eurodollar loans, and as of December 31, 2019, all of the borrowings under the Credit Facility were Eurodollar loans. Principal amounts borrowed are payable on the maturity date, and interest is payable at the end of the applicable interest period. Eurodollar loans bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 1.75% to 2.75% per annum. Due to the weighted average 1-month LIBOR being 1.76% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.01% per annum as of December 31, 2019. 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 assets, 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, 2019, 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, which commenced May 1, 2019. We used approximately $577.5 million of the $587.2 million net proceeds from the issuance of the 2026 Notes 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. We also paid $1.5 million of accrued and unpaid interest up to, but excluding, the date of the Redemption. We used the remaining net proceeds to repay borrowings under the Credit Facility. As of December 31, 2019, we had $600.0 million in aggregate principal amount of the 2026 Notes outstanding.

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 October 1, 2017. Our net proceeds were used to repay and retire all of our previously outstanding second lien term loans and for general corporate purposes. As of December 31, 2019, we had $975.0 million in aggregate principal amount of the 2022 Notes outstanding as a result of the Redemption.

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 the principal amount for the periods noted) set forth in the table below:

Senior Notes	Redemption Period	Redemption Price
2022 Notes	April 1, 2020 through March 31, 2021	107.500%
2022 Notes	April 1, 2021 through September 30, 2021	105.000%
2022 Notes	October 1, 2021 and thereafter	100.000%
2026 Notes	November 1, 2021 through October 31, 2022	103.500%
2026 Notes	November 1, 2022 through October 31, 2023	102.333%
2026 Notes	November 1, 2023 through October 31, 2024	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 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, 2019, 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 contributed to us by our Member.

As of December 31, 2019, we had $77.3 million in aggregate principal of the Convertible Notes outstanding. The Convertible Notes mature on March 1, 2021 and are subordinate to the Senior Notes, which rank senior in right of payment. 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 elected to pay interest in kind on each interest payment date from September 2015 through September 2019. 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 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. See Note 9 of the notes to our consolidated financial statements included in this report for further details of our commitments.

The following table summarizes our contractual cash obligations for both recorded obligations and certain off-balance sheet arrangements and commitments as of December 31, 2019:

	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][b]	$ 2,881,943	$ —	$ 1,093,943	$ 1,188,000	$ 600,000
Interest	787,044	204,075	345,434	153,535	84,000
Operating lease commitments	12,343	9,650	2,591	102	—
Pipeline commitments	9,514,793	644,121	1,333,054	1,330,495	6,207,123
Other	6,215	2,817	2,596	12	790
Total	$ 13,202,338	$ 860,663	$ 2,777,618	$ 2,672,144	$ 6,891,913

(a) The Convertible Notes due in 2021 include a premium of $41.6 million that is payable upon maturity. The premium is accreted over the scheduled maturity period of the debt.

(b) The Credit Facility maturity date will accelerate to December 30, 2021 if more than $200.0 million of the 2022 Notes are outstanding as of December 30, 2021.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in accordance with US GAAP, which requires management to make assumptions and estimates about future events and apply judgments that affect the reported amounts of assets, liabilities, revenues, expenses 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. Proved reserves are defined by the SEC as 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. There are numerous uncertainties inherent in estimating quantities and values of economically recoverable natural gas, oil and NGL reserves, including many factors beyond our control. As a result, estimates of economically recoverable reserves are by their nature uncertain. 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.

We believe the estimates related to natural gas, oil and NGL reserves are critical because we must periodically reevaluate proved reserves along with estimates of future production rates and the timing and amount of future development and operating costs. Our future results of operations and balance sheet for any particular quarterly or annual period could be materially affected by changes in these assumptions.

Natural Gas and Oil Properties

We account for the exploration and development of our natural gas and oil properties under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Geological and geophysical expenses, delay rentals for undeveloped leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized and charged to expense if and when we determine that the well does not contain proved reserves. We did not incur any such charges in the years ended December 31, 2019, 2018 or 2017. The application of the successful efforts method of accounting requires management judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

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, 2019, 2018 or 2017. 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.

We believe that estimates related to the impairment of proved properties are critical because the process to estimate undiscounted future cash flows requires considerable judgment and are sensitive to changes in management's assumptions and estimates of future financial results. In addition, if the carrying amount exceeds the estimated undiscounted future cash flows, we would be required to estimate the fair value of our properties. We believe the estimates and assumptions used in estimating undiscounted future cash flows are reasonable and appropriate for the year ended December 31, 2019, and under these assumptions the undiscounted future cash flows exceeded the carrying value of our proved properties. However, different assumptions and estimates could materially impact the calculated undiscounted future cash flows and the resulting determinations about the impairment of proved properties, which could materially impact our results of operations and financial position. Additionally, future estimates may differ materially from current estimates and assumptions.

We believe that a sensitivity analysis regarding the effect of changes in assumptions on any estimated impairments would be impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, oil and NGL prices decrease or drilling efforts are unsuccessful, we may be required to record an impairment.

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 recorded to exploration expense. 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, 2019, 2018 and 2017, we recorded impairments of $115.8 million, $153.0 million and $183.9 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

DD&A of capitalized drilling and completion costs related to developed 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.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in timing of when depletion expense is recognized. Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to prolong depletion expense recognition.

Business Combinations

Accounting for business combinations 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 most significant assumptions in a business combination include those used to estimate the fair value of the natural gas and oil properties acquired. The fair value of proved and unproved natural gas and oil properties is estimated using an after-tax discounted cash flow analysis based upon significant assumptions including commodity prices; projections of estimated quantities of reserves; risk factors applied to reserves by type; projections of future rates of production; timing and amount of future development and operating costs; and a market-based weighted average cost of capital.

We believe that the estimates related to business combinations are critical because in determining the fair value of assets acquired, we must make significant assumptions, including those listed above. Different assumptions may result in materially different values for these assets which would impact our financial position and future results of operations.

Asset Acquisitions

As part of our business strategy, we periodically pursue the acquisition of natural gas and oil properties. The purchase price in an asset 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 effective date. Therefore, while the consideration to be paid may be fixed, the relative fair value of the assets acquired and liabilities assumed is subject to change during the period between the effective 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.

As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

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 revenue 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.

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.

We believe that the estimates related to contingencies are critical because we must assess the probability of losses related to contingencies. In addition, we must determine the estimated present value of future liabilities. Future results of operations for any particular quarterly or annual period could be materially affected by changes in our assumptions. See Note 9 of the notes to our consolidated financial statements included in this report for further discussion of our contingencies.

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. We have estimated 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. 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. We only enter into derivative contracts with counterparties that we determine are creditworthy, and such creditworthiness is subject to periodic review. Any non-performance risk is considered in the valuation of our derivative instruments, but to date it 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.

We believe the estimates related to derivative instruments are critical because our financial condition and results of operations can be significantly impacted by changes in the market value of our derivative instruments due to the volatility of natural gas, oil and NGL prices. Future results of operations for any particular quarterly or annual period could be materially affected by changes in our assumptions.

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 for the periods indicated regarding our net production volumes; natural gas, oil and NGL sales; average sales prices received; and certain of our operating expenses. Average sales prices listed in the table below are based on mcf of natural gas and bbls of oil and NGL:

	Years Ended December 31,		
	2019	2018	2017
Net Production Volumes:			
Natural gas (mmcf)	638,243	457,747	240,980
Oil (mbbls)	4,794	2,262	2,492
NGL (mbbls)	8,685	3,974	3,286
Natural Gas Equivalent (mmcfe)	719,113	495,168	275,653
Natural Gas, Oil and NGL Sales ($ in thousands):			
Natural gas	$ 1,589,099	$ 1,444,368	$ 706,866
Oil	241,521	133,786	111,441
NGL	148,639	109,221	77,054
Settlements of commodity derivatives	191,682	(56,743)	23,396
Change in fair value of commodity derivatives	249,457	(34,138)	188,650
Total	$ 2,420,398	$ 1,596,494	$ 1,107,407
Average Daily Net Production Volumes:			
Natural gas (mmcf/d)	1,749	1,254	660
Oil (mbbls/d)	13	6	7
NGL (mbbls/d)	24	11	9
Natural Gas Equivalent (mmcfe/d)	1,970	1,357	755
Average Sales Prices:			
Natural gas ($/mcf)	$ 2.49	$ 3.16	$ 2.93
Oil ($/bbl)	$ 50.38	$ 59.15	$ 44.71
NGL ($/bbl)	$ 17.11	$ 27.48	$ 23.45
Natural Gas Equivalent ($/mcfe)	$ 2.75	$ 3.41	$ 3.25
Settlements of commodity derivatives ($/mcfe)	0.27	(0.11)	0.08
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.02	$ 3.30	$ 3.33
Operating Expenses ($/mcfe):			
Lease operating expenses	$ 0.10	$ 0.10	$ 0.13
Gathering, processing and transportation expenses	$ 1.19	$ 1.33	$ 1.24
Production and ad valorem taxes	$ 0.05	$ 0.05	$ 0.05
General and administrative expenses, including related party	$ 0.08	$ 0.13	$ 0.17
Natural gas and oil depreciation, depletion and amortization	$ 0.98	$ 1.01	$ 1.11
Depreciation and amortization of other assets	$ —	$ 0.01	$ 0.01

Year Ended December 31, 2019 Compared to 2018

Natural Gas Sales. In 2019 and 2018, natural gas sales (excluding the effects of derivatives) were $1.59 billion and $1.44 billion, respectively. In 2019 and 2018, we sold 638.2 bcf and 457.7 bcf of natural gas, at weighted average prices of $2.49 and $3.16 per mcf, respectively (excluding the effects of derivatives). The $144.7 million increase in natural gas sales (excluding the effects of derivatives) during 2019 compared to 2018 was driven by a 39% increase in natural gas production, which was partially offset by a $0.67 per mcf decrease in the average sales price received for natural gas.

We recognized a $468.1 million gain on natural gas derivatives in 2019 comprised of a $303.5 million increase in the fair value and $164.6 million of net settlement gains. We recognized a $146.8 million loss on natural gas derivatives in 2018 comprised of $42.9 million of net settlement losses and a $103.9 million decrease in the fair value.

A change in natural gas prices has a significant impact on our sales and cash flows. Assuming our production levels for 2019 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 $63.8 million in 2019.

Oil Sales. In 2019 and 2018, oil sales (excluding the effects of derivatives) were $241.5 million and $133.8 million, respectively. In 2019 and 2018, we sold 4.8 million barrels (mmbbls) and 2.3 mmbbls of oil at weighted average prices of $50.38 and $59.15 per bbl, respectively, (excluding the effects of derivatives). The $107.7 million increase in oil sales (excluding the effects of derivatives) in 2019 compared to 2018 was driven by a 112% increase in oil production, which was partially offset by an $8.77 per bbl decrease in the average sales price received for oil.

We recognized a $43.8 million loss on oil derivatives in 2019 comprised of a $45.1 million decrease in the fair value, partially offset by $1.3 million of net settlement gains. We recognized a $37.8 million gain on oil derivatives in 2018 comprised of a $54.9 million increase in the fair value, which was partially offset by $17.1 million of net settlement losses.

A change in oil prices has a direct impact on our sales and cash flows. Assuming our production levels for 2019 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 $4.8 million in 2019.

NGL Sales. In 2019 and 2018, NGL sales (excluding the effects of derivatives) were $148.6 million and $109.2 million, respectively. In 2019 and 2018, we sold 8.7 mmbbls and 4.0 mmbbls of NGL at weighted average prices of $17.11 and $27.48 per bbl, respectively, (excluding the effects of derivatives). The $39.4 million increase in NGL sales (excluding the effects of derivatives) during 2019 compared to 2018 was driven by a 119% increase in NGL production, which was partially offset by a $10.37 per bbl decrease in the average sales price received for NGL.

We recognized a $16.8 million gain on NGL derivatives in 2019 comprised of $25.7 million of net settlement gains, partially offset by an $8.9 million decrease in the fair value. We recognized an $18.2 million gain on NGL derivatives in 2018 comprised of a $14.9 million increase in the fair value and $3.3 million of net settlement gains.

A change in NGL prices has a direct impact on our sales and cash flows. Assuming our production levels for 2019 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 $8.7 million in 2019.

Lease Operating Expenses. Lease operating expenses were $72.6 million and $50.2 million in 2019 and 2018, respectively. Total lease operating expenses increased as a result of an increase in producing wells during 2019 compared to 2018. On a per unit basis, lease operating expenses were $0.10 per mcfe in both 2019 and 2018.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $856.1 million and $658.1 million in 2019 and 2018, respectively. On a per unit basis, gathering, processing and transportation expenses were $1.19 and $1.33 per mcfe in 2019 and 2018, respectively. The per unit decrease for 2019 compared to 2018 was due to increased production levels which allowed us to optimize our firm transportation commitments.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $34.2 million and $23.4 million in 2019 and 2018, respectively. Production taxes have increased as production volumes have increased and were $21.0 million and $14.9 million in 2019 and 2018, 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 flat at $0.03 per mcfe in 2019 and 2018, respectively.

Ad valorem taxes were $13.2 million and $8.5 million in 2019 and 2018, 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, valuation factors set by the state and tax rates determined by the various counties. As such, total ad valorem taxes have increased due to an increase in producing wells.

Exploration Expenses. Exploration expenses were $124.5 million and $156.5 million in 2019 and 2018, respectively. In 2019 and 2018, we impaired $115.8 million and $153.0 million, 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. General and administrative expenses were $61.0 million and $63.8 million in 2019 and 2018, respectively. On a per unit basis, general and administrative expenses were $0.08 and $0.13 per mcfe in 2019 and 2018, respectively, the decrease of which was primarily the result of increased production in 2019 and $9.4 million of non-recurring legal expenses in 2018.

Acquisition Expenses. Acquisition expenses were $9.4 million in 2018, which were incurred in connection with the closing of the CNX and Hess Acquisition and the UMD Acquisition, as discussed in Note 3, *2018 Acquisitions*, of the notes to our 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, the acquisition expenses were not capitalized.

Natural Gas and Oil Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of natural gas and oil properties was $702.4 million and $500.8 million in 2019 and 2018, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs and the related underlying reserves, was $0.98 and $1.01 per mcfe in 2019 and 2018, respectively. The per unit decrease from 2018 to 2019 was the result of a 21% increase in total proved reserves, which have increased primarily through the drill bit.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $3.2 million and $3.9 million in 2019 and 2018, respectively. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. Our other property and equipment consist mainly of a field office and other corporate assets.

Interest Expense. Interest expense was $109.1 million and $92.2 million in 2019 and 2018, respectively, detailed as follows along with our weighted average debt outstanding:

	Years Ended December 31,	
($ in thousands)	2019	2018
Interest expense on Credit Facility	$ 60,272	$ 41,073
Interest expense on 2022 Notes	97,500	138,762
Interest expense on 2026 Notes	42,002	9,333
Interest expense on Convertible Notes	4,906	4,320
Amortization of debt discounts, premium and issuance costs	23,928	21,382
Other	3,876	3,763
Capitalized interest	(123,370)	(126,406)
Total Interest Expense, net	$ 109,114	$ 92,227
Weighted Average Debt Outstanding:		
Credit Facility	$ 1,119,518	$ 420,345
2022 Notes	975,000	1,382,055
2026 Notes	600,000	134,795
Convertible Notes	75,334	70,833
Weighted Average Debt Outstanding	$ 2,769,852	$ 2,008,028

The increase in interest expense in 2019 compared to 2018 was primarily due to an increase in our weighted average borrowings under our Credit Facility in 2019.

Losses 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.

Year Ended December 31, 2018 Compared to 2017

Natural Gas Sales. In 2018 and 2017, natural gas sales (excluding the effects of derivatives) were $1.44 billion and $706.9 million, respectively. In 2018 and 2017, we sold 457.7 bcf and 241.0 bcf of natural gas, at weighted average prices of $3.16 and $2.93 per mcf, respectively (excluding the effects of derivatives). The $737.5 million increase in natural gas sales (excluding the effects of derivatives) during 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.

We recognized a $146.8 million loss on natural gas derivatives in 2018 comprised of a $103.9 million decrease in the fair value and $42.9 million of net settlement losses . We recognized a $213.0 million gain on natural gas derivatives in 2017 comprised of a $196.2 million increase in fair value and $16.8 million of net settlement gains.

Oil Sales. In 2018 and 2017, oil sales (excluding the effects of derivatives) were $133.8 million and $111.4 million, respectively. In 2018 and 2017, we sold 2.3 mmbbls and 2.5 mmbbls of oil at weighted average prices of $59.15 and $44.71 per bbl, respectively, (excluding the effects of derivatives). The $22.4 million increase in oil sales (excluding the effect of derivatives) during 2018 compared to 2017 was driven by a 32% increase in the average sales price received for oil and partially offset by a 9% decrease in oil production.

We recognized a $37.8 million gain on oil derivatives in 2018 comprised of a $54.9 million increase in the fair value, which was partially offset by $17.1 million of net settlement losses. We recognized a $1.0 million loss on oil derivatives in 2017 comprised of a $7.6 million decrease in the fair value, which was partially offset by $6.6 million of net settlement gains.

NGL Sales. In 2018 and 2017, NGL sales (excluding the effects of derivatives) were $109.2 million and $77.1 million, respectively. In 2018 and 2017, we sold 4.0 mmbbls and 3.3 mmbbls of NGL at weighted average prices of $27.48 and $23.45 per bbl, respectively, (excluding the effects of derivatives). The $32.1 million increase in NGL sales (excluding the effect of derivatives) during 2018 compared to 2017 was driven by a 21% increase in NGL production and a 17% increase in the average sales price received for NGL.

We recognized an $18.2 million gain on NGL derivatives during 2018 comprised of a $14.9 million increase in the fair value and $3.3 million of net settlement gains.

Lease Operating Expenses. Lease operating expenses were $50.2 million and $35.3 million in 2018 and 2017, respectively. On a per unit basis, lease operating expenses were $0.10 and $0.13 per mcfe in 2018 and 2017, respectively. Total lease operating expenses increased as a result of an increase in producing wells during 2018 compared to 2017. The per unit decrease 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.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses were $658.1 million and $341.8 million in 2018 and 2017, respectively. On a per unit basis, gathering, processing and transportation expenses were $1.33 and $1.24 per mcfe in 2018 and 2017, respectively. The per unit increase was due to increases in contracted in-service firm transportation capacity in excess of increases in production volumes.

Production and Ad Valorem Taxes. Production and ad valorem taxes were $23.4 million and $14.1 million in 2018 and 2017, respectively. Production taxes have increased as production volumes have increased and were $14.9 million and $8.1 million in 2018 and 2017, 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 flat at $0.03 per mcfe in 2018 and 2017, respectively.

Ad valorem taxes were $8.5 million and $6.0 million in 2018 and 2017, 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, valuation factors set by the state and tax rates determined by the various counties. As such, total ad valorem taxes have increased due to an increase in producing wells.

Exploration Expenses. Exploration expenses were $156.5 million and $186.2 million in 2018 and 2017, respectively. In 2018 and 2017, we impaired $153.0 million and $183.9 million, respectively, of unproved natural gas and oil properties for which the leases are expected to expire.

General and Administrative Expenses, Including Related Party. General and administrative expenses, including related party expenses, were $63.8 million and $46.3 million in 2018 and 2017, respectively. On a per unit basis, general and administrative expenses, including related party expenses, were $0.13 and $0.17 per mcfe in 2018 and 2017, respectively. Total general and administrative expenses, including related party expenses, increased in 2018 primarily due to a 10% increase in our employee count and related costs from 2017 to 2018 and $9.4 million of non-recurring legal expenses. These increases in general and administrative expenses, including related party expenses, were offset by an 80% increase in production volumes from 2017 to 2018, creating the decrease on a per unit basis.

Acquisition Expenses. Acquisition expenses were $9.4 million in 2018, which were incurred in connection with the closing of the CNX and Hess Acquisition and the UMD Acquisition, as discussed in Note 3, *2018 Acquisitions*, of the notes to our 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, the acquisition 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 and $305.6 million in 2018 and 2017, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs and the related underlying reserves, was $1.01 and $1.11 per mcfe in 2018 and 2017, respectively. The per unit decrease from 2017 to 2018 was the result of a 79% increase in total proved reserves, which was partially offset by a 57% increase in net capitalized costs during the same period.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $3.9 million and $1.9 million in 2018 and 2017, respectively. Property and equipment costs are depreciated on a straight-line basis over the estimated useful lives of the assets. Our other property and equipment consist mainly of a field office and other corporate assets. The increase in 2018 from 2017 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.

Interest Expense. Interest expense was $92.2 million and $73.4 million in 2018 and 2017, respectively, detailed as follows along with our weighted average debt outstanding:

	Years Ended December 31,	
($ in thousands)	2018	2017
Interest expense on Credit Facility	$ 41,073	$ 14,908
Interest expense on 2022 Notes	138,762	110,448
Interest expense on 2026 Notes	9,333	—
Interest expense on Convertible Notes	4,320	3,552
Interest expense on second lien term loans	—	37,502
Amortization of debt discounts, premium and issuance costs	21,382	21,632
Other	3,763	7,583
Capitalized interest	(126,406)	(122,273)
Total Interest Expense, net	$ 92,227	$ 73,352
Weighted Average Debt Outstanding:		
Credit Facility	$ 420,345	$ —
2022 Notes	1,382,055	1,109,589
2026 Notes	134,795	—
Convertible Notes	70,833	69,358
Second lien term loans	—	335,822
Weighted Average Debt Outstanding	$ 2,008,028	$ 1,514,769

The increase in interest expense in 2018 compared to 2017 was primarily due to an increase in our weighted average borrowings under our Credit Facility in 2018.

Change in Fair Value of Embedded Derivative. The change in fair value of the embedded derivative in the Convertible Notes resulted in a gain of $18.9 million and a loss of $19.3 million in 2018 and 2017, respectively. In general, changes in the estimated price of the Convertible Notes, the par value and accrued interest outstanding, the probability and timing of 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 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, and we recognized a loss on purchases or exchanges of debt of $114.1 million in 2017 related to the repayment and retirement of previously outstanding second lien term loans and the retirement of a prior credit facility, as discussed in Note 5, *Credit Facility* and *Senior Notes*, of the notes to our consolidated financial statements included in this report.

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. 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 2019, 2018 and 2017, the average daily Henry Hub spot market price of natural gas was $2.51 per mmbtu, $3.12 per mmbtu and $2.96 per mmbtu, respectively, and the average daily West Texas Intermediate oil price was $57.04 per bbl, $64.90 per bbl, and $50.85 per bbl, respectively. Approximately 88% of our December 31, 2019 proved reserves were natural gas; therefore, changes in realized natural gas pricing will affect us more than changes in realized oil or NGL pricing.

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, 2019, our natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*. We receive a fixed price and pay a variable market price to the counterparty for the hedged commodity.
- *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 relative to NYMEX: 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, 2019, we had a net asset commodity derivative position of $318.9 million. The following table sets forth the volumes per day associated with our outstanding natural gas derivative instruments as of December 31, 2019, the contracted weighted average natural gas prices, the contracted weighted average basis swap spreads and the estimated fair values:

		Weighted Average Prices ($/mmbtu)				
	Average Volume (mmbtu/d)	Swap Strike Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ 319,373
2020	1,512,000	$ 2.72				
2021	835,000	$ 2.60				
2022	530,000	$ 2.52				
2023	100,000	$ 2.70				
Collars:						19,091
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						17,013
2021	270,000		$ 2.91	$ 2.50	$ 2.00	
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(30,159)
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	260,000		$ 3.04			
2023	170,000		$ 3.00			
Basis swaps:						(9,341)
2020	870,000	$ (0.32)				
2021	368,000	$ (0.30)				
2022	5,000	$ 0.11				
Total Estimated Fair Value						$ 315,977

The following table sets forth the volumes per day associated with our outstanding oil derivative instruments as of December 31, 2019, the contracted weighted average oil prices and the estimated fair values:

		Weighted Average Prices ($/bbl)				
	Average Volume (bbl/d)	Swap Strike Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Oil:						
Swaps:						$ (1,692)
2020	5,700	$ 56.47				
2021	2,000	$ 58.42				
Three-way collars:						613
2021	1,000		$ 65.30	$ 52.50	$ 42.50	
Call options:						(1,982)
2020	4,750		$ 70.00			
2021	3,500		$ 70.00			
Total Estimated Fair Value						$ (3,061)

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of December 31, 2019, the contracted weighted average NGL prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Strike Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 6,016
2020	1,500	$ 30.14		
Call options - Propane:				(36)
2020	3,150		$ 33.60	
Total Estimated Fair Value				$ 5,980

The fair value of our derivative instruments is largely influenced by the future prices of natural gas, oil and NGL. The following table sets forth the changes in the fair value of our derivative instruments due to a hypothetical 10% change in future prices as of December 31, 2019. 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 associated with the derivative instrument.

($ in thousands)	Hypothetical 10% Increase in Future Prices	Hypothetical 10% Decrease in Future Prices
Natural gas	$ (284,531)	$ 275,916
Oil	$ (21,182)	$ 18,185
NGL	$ (1,069)	$ 1,055

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. We only enter into derivative contracts with counterparties that we determine are creditworthy, and such creditworthiness 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 customers that constitute 10% or more of our revenues, before the effects of derivatives:

	Years Ended December 31,		
	2019	2018	2017
Company A	16%	23%	25%
Company B	10%	16%	24%

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; however, we do not believe the loss of any single customer would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and numerous customers. We historically have not incurred losses on our natural gas, oil and NGL receivables.

We also have joint interest receivables, which arise from billings to entities that own working interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases. We have little ability to control whether these entities will participate in our wells but can require these entities to prepay drilling costs. We historically have not incurred losses on our joint interest receivables.

Interest Rate Risk

Borrowings under the Credit Facility bear interest at a variable tiered rate based on facility usage plus the 1-month LIBOR, resulting in a weighted average interest rate of 4.01% as of December 31, 2019. The LIBOR component of our interest related to borrowings under the Credit Facility exposes us to interest rate risk. A 1.00% increase in LIBOR in 2019 would have resulted in an estimated increase of $11.2 million in interest expense on borrowings under the Credit Facility. As of December 31, 2019, the Convertible Notes, 2022 Notes and 2026 Notes bore interest at fixed rates of 6.50%, 10.00% and 7.00%, respectively, resulting in no interest rate risk on such instruments. We had no outstanding interest rate derivatives at December 31, 2019.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations during 2019, 2018 or 2017. Although the impact of inflation has been insignificant recently, 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, 2019 and 2018, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 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
February 21, 2020

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED BALANCE SHEETS

	December 31,	
($ in thousands)	**2019**	**2018**
Current Assets:		
Cash and cash equivalents	$ 7,346	$ 11,030
Accounts receivable – natural gas, oil and NGL sales	260,759	401,814
Accounts receivable – joint interest and other	20,425	50,531
Short-term derivative assets	248,118	52,404
Other current assets	8,468	6,135
Total Current Assets	545,116	521,914
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	8,233,964	7,066,947
Other property and equipment	30,818	27,454
Less: accumulated depreciation, depletion and amortization	(1,890,506)	(1,185,772)
Property and Equipment, net	6,374,276	5,908,629
Other Assets:		
Long-term derivative assets	70,778	39,543
Other long-term assets	20,248	16,736
Total Assets	$ 7,010,418	$ 6,486,822
Current Liabilities:		
Accounts payable	$ 68,364	$ 106,839
Revenue payable	99,300	178,111
Accrued interest	36,787	41,510
Short-term derivative liabilities	—	1,068
Other current liabilities	280,841	328,580
Total Current Liabilities	485,292	656,108
Long-Term Liabilities:		
Long-term debt, net	2,838,676	2,582,820
Long-term derivative liabilities	—	21,441
Other long-term liabilities	5,067	11,356
Total Long-Term Liabilities	2,843,743	2,615,617
Commitments and contingencies (Note 9)		
Member's Equity	3,681,383	3,215,097
Total Liabilities and Member's Equity	$ 7,010,418	$ 6,486,822

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

	Years Ended December 31,		
($ in thousands)	**2019**	**2018**	**2017**
Revenues:			
Natural gas	$ 1,589,099	$ 1,444,368	$ 706,866
Oil	241,521	133,786	111,441
NGL	148,639	109,221	77,054
Commodity derivative gain (loss)	441,139	(90,881)	212,046
Total Revenues	2,420,398	1,596,494	1,107,407
Operating Expenses:			
Lease operating expenses	72,606	50,163	35,259
Gathering, processing and transportation expenses	856,126	658,117	341,765
Production and ad valorem taxes	34,167	23,362	14,050
Exploration expenses	124,477	156,450	186,152
General and administrative expenses	61,027	63,794	7,960
General and administrative expenses – related party	—	—	38,365
Acquisition expenses	—	9,407	—
Natural gas and oil depreciation, depletion and amortization	702,414	500,773	305,573
Depreciation and amortization of other assets	3,239	3,912	1,905
Total Operating Expenses	1,854,056	1,465,978	931,029
Income from Operations	566,342	130,516	176,378
Other (Expense) Income:			
Interest expense, net	(109,114)	(92,227)	(73,352)
Change in fair value of embedded derivative	5,026	18,865	(19,261)
Losses on purchases or exchanges of debt	—	(62,233)	(114,052)
Other income	3,711	683	1,572
Total Other Expense	(100,377)	(134,912)	(205,093)
Net Income (Loss)	$ 465,965	$ (4,396)	$ (28,715)

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

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

	Years Ended December 31,		
($ in thousands)	**2019**	**2018**	**2017**
Balance, Beginning of Period	$ 3,215,097	$ 2,182,500	$ 2,067,183
Contributions from Member	321	1,036,993	132,090
Contribution of debt held by Member	—	—	11,942
Net income (loss)	465,965	(4,396)	(28,715)
Balance, End of Period	$ 3,681,383	$ 3,215,097	$ 2,182,500

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, 2019	2018	2017
Cash Flows from Operating Activities:			
Net income (loss)	$ 465,965	$ (4,396)	$ (28,715)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	705,653	504,685	307,478
Change in fair value of commodity derivatives	(249,457)	34,138	(188,650)
Impairment of unproved natural gas and oil properties	115,802	153,047	183,885
Non-cash interest expense	27,305	28,301	28,004
Change in fair value of embedded derivative	(5,026)	(18,865)	19,261
Losses on purchases or exchanges of debt	—	62,233	114,052
Other	148	(1,218)	2,766
Changes in operating assets and liabilities			
Decrease (increase) in accounts receivable and other assets	159,274	(274,558)	(95,882)
(Decrease) increase in accounts payable, liabilities and other	(79,546)	205,366	143,245
Net Cash Provided by Operating Activities	1,140,118	688,733	485,444
Cash Flows from Investing Activities:			
Drilling and completion costs	(1,125,216)	(906,064)	(653,942)
Acquisitions of natural gas and oil properties	(258,001)	(1,409,494)	(429,890)
Proceeds from divestitures of natural gas and oil properties	12,474	6,564	79,329
Reductions in deposits on pipeline capacity	—	—	151,193
Additions to other property and equipment	(3,547)	(1,512)	(257)
Net Cash Used in Investing Activities	(1,374,290)	(2,310,506)	(853,567)
Cash Flows from Financing Activities:			
Proceeds from credit facility borrowings	1,270,000	1,525,000	—
Repayment of credit facility borrowings	(1,030,000)	(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)
Cash paid for debt issuance costs	(9,512)	(11,725)	(18,142)
Cash paid for debt prepayment costs	—	(52,500)	(70,999)
Contributions from Member	—	567,647	132,000
Net Cash Provided by Financing Activities	230,488	1,513,588	218,845
Net Decrease in Cash and Cash Equivalents	(3,684)	(108,185)	(149,278)
Cash and Cash Equivalents, Beginning of Period	11,030	119,215	268,493
Cash and Cash Equivalents, End of Period	$ 7,346	$ 11,030	$ 119,215
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest and interest paid in kind	$ 88,392	$ 63,583	$ 12,901
Supplemental disclosures of significant non-cash investing and financing activities:			
(Decrease) increase in accrued capital expenditures	$ (96,471)	$ 56,740	$ 22,224
Contributions from Member	$ —	$ 469,346	$ —
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, “we”, “our” or “us”), 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). ARUH is a wholly-owned subsidiary of Ascent Resources Operating, LLC (our Member), which is an indirect, wholly-owned subsidiary of Ascent Resources, LLC (our Parent). Together, The Energy & Minerals Group (EMG) and First Reserve Corporation (First Reserve) own a majority interest in our Parent.

Our accompanying consolidated financial statements and notes were prepared in accordance with United States generally accepted accounting principles (US GAAP), and intercompany accounts and balances have been eliminated.

Business Segment Information

We evaluated how we are organized and managed and 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.

We have a single, company-wide management team that manages all properties as a whole rather than by distinct operating segments. We measure financial performance as a single enterprise and not on a geographical basis.

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 on 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 our estimates.

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.

Significant Accounting Policies

Cash and Cash Equivalents. We consider investments in all highly liquid instruments with original maturities of three months or less at the date of purchase to be cash equivalents. We maintain our cash in accounts that may not be federally insured beyond certain limits; however, we have not experienced any losses in such accounts and believe we are not exposed to any significant credit risk on such accounts.

Accounts Receivable. We sell natural gas, oil and NGL to various customers and participate 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. If we had past due accounts, they would generally be written off against the allowance for doubtful accounts after all attempts to collect the balance are exhausted. Accounts receivable at December 31, 2019 and 2018 were $281.2 million and $452.3 million, respectively, and consist primarily of accrued natural gas, oil and NGL revenue receivables and receivables from joint interest billings to owners of properties we operate. 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. We account for the exploration and development of our natural gas and oil properties under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Geological and geophysical expenses, delay rentals for undeveloped leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized and charged to expense if and when we determine that the well does not contain proved reserves. We did not incur any such charges in the years ended December 31, 2019, 2018 or 2017. The application of the successful efforts method of accounting requires management judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

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, 2019, 2018 or 2017. 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 recorded to exploration expense. 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, 2019, 2018 and 2017, we recorded impairments of $115.8 million, $153.0 million and $183.9 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. Depreciation, depletion and amortization (DD&A) of capitalized drilling and completion costs related to developed 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 $3.2 million, $3.9 million and $1.9 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Business Combinations. Accounting for business combinations 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 most significant assumptions in a business combination include those used to estimate the fair value of the natural gas and oil properties acquired. The fair value of proved and unproved natural gas and oil properties is estimated using an after-tax discounted cash flow analysis based upon significant assumptions including commodity prices; projections of estimated quantities of reserves; risk factors applied to reserves by type; projections of future rates of production; timing and amount of future development and operating costs; and a market-based weighted average cost of capital.

Asset Acquisitions. As part of our business strategy, we periodically pursue the acquisition of natural gas and oil properties. The purchase price in an asset 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 effective date. Therefore, while the consideration to be paid may be fixed, the relative fair value of the assets acquired and liabilities assumed is subject to change during the period between the effective 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 are obligated to retire our natural gas and oil wells at the end of their lives. We recognize the fair value of a retirement obligation in the period in which a natural gas or oil well is acquired or spud and accrete it to its present value each period, until the well is retired or 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 as a component of DD&A on our consolidated statements of operations. The associated liabilities were $1.7 million as of both December 31, 2019 and 2018.

Capitalized Interest. We capitalize 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 our weighted average interest rate, based on our 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 our term debt have been presented as a reduction to long-term debt on the consolidated balance sheets. We amortize 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. We amortize 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. We recognize revenues from the sale of natural gas, oil and NGL based on our share of volumes sold. We adopted ASU 2014-09, ASC 606 (as defined below) with an effective date as of January 1, 2018 using the modified retrospective transition approach, which is discussed further in Note 2.

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

	Years Ended December 31,		
	2019	2018	2017
Company A	16%	23%	25%
Company B	10%	16%	24%

We do not believe the loss of any single customer would materially impact our operating results, as natural gas, oil and NGL are fungible products with well-established markets and numerous customers. We historically have not incurred losses on our natural gas, oil and NGL receivables.

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.

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. We have estimated 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. 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.

Our 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 on 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 counterparty on the accompanying consolidated balance sheets.

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. We only enter into derivative contracts with counterparties that we determine are creditworthy, and such creditworthiness is subject to periodic review. Any non-performance risk is considered in the valuation of our derivative instruments, but to date it has not had a material impact on the values of our derivatives. See Note 6 for further discussion of our 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 our accounting policy for property and equipment.

Income Taxes. We are treated as a disregarded entity for income tax purposes. Our 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 our consolidated financial statements.

Reclassifications

Certain reclassifications have been made to our 2018 and 2017 consolidated financial statements to conform to the presentation used for the 2019 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 our financial statements.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments (Topic 326)*. This ASU amends guidance on reporting credit losses for assets held at amortized cost basis and available for sale debt securities. For assets held at amortized cost basis, this ASU eliminates the probable initial recognition threshold in current US GAAP and instead requires an entity to reflect its current estimate of all expected credit losses. The amendments affect loans, debt securities, trade receivables, net investments in leases, off balance sheet credit exposures, reinsurance receivables and any other financial assets not excluded from the scope that have the contractual right to receive cash. These amendments will be effective for annual reporting periods, and interim periods within those periods, beginning after December 15, 2019 for public entities. For non-public entities, the amendments will be effective for annual reporting periods beginning after December 15, 2022, including interim periods within those fiscal years. The amendments in this guidance should be applied using the modified retrospective approach with a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. We are currently evaluating the impact this standard will have on our financial statements and related disclosures, and we do not expect it to have a material impact.

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 as defined by Topic 842 (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 and presentation of expenses. This accounting standards update also requires certain quantitative and qualitative disclosures about leasing arrangements. We expect to 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. The FASB has issued subsequent updates, including ASU 2018-01, ASU 2018-11 and ASU 2019-01, in order to clarify its original intent under Topic 842 and provide additional guidance for transitional disclosures and practical expedients. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018 for public business entities. For non-public entities, the amendments will be effective for annual reporting periods beginning after December 15, 2020 and for interim periods beginning after December 15, 2021, with early adoption permitted. We are in the process of evaluating the impact this standard will have on our financial statements and related disclosures. Based on our preliminary review, we expect to record leases with durations greater than twelve months on our balance sheet along with expanded lease disclosures and internal control changes necessary for adoption.

Subsequent Events

As of February 21, 2020, the date the consolidated financial statements were issued, we completed our evaluation of material subsequent events for disclosure, and no items were identified.

2. Revenue from Contracts with Customers

Our revenues are derived from the sale of natural gas, oil and NGL and 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, in accordance with ASC 606, *Revenue from Contracts with Customers* (ASC 606). We typically receive payment for natural gas, oil and NGL sales within 30 days of the month of delivery. A significant number of our sales contracts are short-term in nature generally through evergreen contracts with terms of one year or less, and our sales contracts with a term greater than one year have no material long-term fixed consideration.

Under our natural gas sales contracts, we deliver natural gas to the customer at a delivery point specified under the sales contracts, utilizing third parties to gather, compress, process and transport our natural gas. Our sales contracts provide that we generally receive revenue for the sale of our natural gas based on a specific index price adjusted for pricing differentials. We transfer control of the natural gas at the delivery point and recognize 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 us directly or to the processor under processing contracts. For NGL sold by us directly, the sales contracts provide that the product is delivered to the customer at an agreed upon delivery point and that we generally receive revenue for the sale of our NGL based on a specific index price adjusted for pricing differentials. We transfer control of the product to the customer at the delivery point and recognize 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 us to the processor at the tailgate of the processing plant, and revenue is recognized based on the price received from the processor.

Under our oil sales contracts, oil is sold to the customer from storage tanks near the wellhead, and we receive revenue for the sale of our oil based on a contractually agreed upon index price, net of pricing differentials. We transfer control of the product to the customer at the storage tanks and recognize revenue based on the contract price.

Our revenues from the sale of natural gas, oil and NGL are each presented separately on our consolidated statements of operations. We believe that the disaggregation of revenue into these three major product types appropriately depicts the requirements of ASC 606.

Under our sales contracts, customers are invoiced after our performance obligations have been satisfied, generally when control of the product has been transferred to the customer, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At December 31, 2019 and 2018, receivables from contracts with customers were $260.8 million and $401.8 million, respectively, and were reported in accounts receivable – natural gas, oil and NGL sales on the consolidated balance sheets.

3. Acquisitions

2018 Acquisitions

During the third quarter of 2018, we 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, 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, including post-closing adjustments. Funding for the CNX and Hess Acquisition consisted of borrowings under the Credit Facility and cash proceeds contributed to us from a common equity offering by our Parent. In connection with the CNX and Hess Acquisition, during the year ended December 31, 2018, we paid approximately $6.9 million of acquisition expenses, 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, we 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	$	766,141
Assets acquired:		
Proved natural gas and oil properties	$	403,726
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		(542)
Asset retirement obligations		(340)
Fair Value of Net Assets Acquired	$	766,141

The following table presents the revenues and net income contributed by the assets acquired in the CNX and Hess Acquisition on our 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, 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 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 our Parent.

UMD Acquisition. On July 13, 2018, we 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 our Parent. The cash consideration was funded using proceeds contributed to us from a common equity offering by our Parent. Upon the closing of the UMD Acquisition in July 2018, our agreements with UMD discussed in Note 8, *UMD Agreements*, were terminated. In connection with the UMD Acquisition, during the year ended December 31, 2018, we paid approximately $2.5 million of acquisition expenses, 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, we 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 our 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 our 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

4. Property and Equipment

Net property and equipment included the following:

($ in thousands)	December 31, 2019	December 31, 2018
Proved natural gas and oil properties	$ 7,155,998	$ 5,457,911
Unproved natural gas and oil properties	1,077,966	1,609,036
Other property and equipment	30,818	27,454
Total Property and Equipment	8,264,782	7,094,401
Accumulated depreciation, depletion and amortization	(1,890,506)	(1,185,772)
Property and Equipment, net	$ 6,374,276	$ 5,908,629

At December 31, 2019 and 2018, we did not have any capitalized well costs associated with exploratory wells that were pending determination of proved reserves.

5. Long-Term Debt

Our long-term debt consisted of the following:

($ in thousands)	December 31, 2019	December 31, 2018
Credit Facility[(a)]	$ 1,188,000	$ 948,000
Senior notes due 2022[(b)]	975,000	975,000
Senior notes due 2026[(c)]	600,000	600,000
Convertible notes due 2021[(d)]	77,336	74,116
Embedded derivative	—	5,026
Net debt issuance costs	(3,522)	(4,243)
Net debt discounts and premiums	1,862	(15,079)
Total Long-Term Debt, net	$ 2,838,676	$ 2,582,820

(a) The interest rate was 4.01% and 4.36% as of December 31, 2019 and 2018, respectively.
(b) The interest rate was 10.00% as of December 31, 2019 and 2018.
(c) The interest rate was 7.00% as of December 31, 2019 and 2018.
(d) The interest rate was 6.50% as of December 31, 2019 and 2018.

Credit Facility

Our $2.5 billion senior secured revolving credit facility (Credit Facility) matures on April 1, 2024, and as of December 31, 2019, it had a fully committed borrowing base of $2.0 billion, of which $250.0 million was authorized for letters of credit. The maturity date will accelerate to December 30, 2021 if more than $200.0 million of the 2022 Notes (defined below) are outstanding as of December 30, 2021. The Credit Facility is secured by liens on substantially all of our assets, including our natural gas and oil properties. The amount available to be borrowed under our 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 the value of our commodity hedge positions. Additionally, we may request an interim redetermination of the borrowing base in certain circumstances, including acquisitions of proved reserves in excess of certain thresholds. As of December 31, 2019, we had $1.2 billion of borrowings outstanding and $170.5 million of letters of credit outstanding under the Credit Facility.

Under the Credit Facility agreement, we may borrow either base rate loans or Eurodollar loans, and as of December 31, 2019, all of the borrowings under the Credit Facility were Eurodollar loans. Principal amounts borrowed are payable on the maturity date, and interest is payable at the end of the applicable interest period. Eurodollar loans bear interest at a rate per annum equal to the London Interbank Offered Rate (LIBOR) plus an applicable margin ranging from 1.75% to 2.75% per annum based on Credit Facility utilization. Due to the weighted average 1-month LIBOR being 1.76% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 4.01% per annum as of December 31, 2019. We may repay any amounts borrowed prior to the maturity date without any premium or penalty.

Under the Credit Facility agreement, we are subject to commitment fees payable to the administrative agent for the unutilized portion of our available borrowing base, the rate of which ranges from 0.375% to 0.50% based on Credit Facility utilization. Additionally, we are subject to letter of credit participation fees payable to the administrative agent which escalate based on applicable margins, ranging from 1.75% to 2.75% per annum, in accordance with the Credit Facility utilization. We are 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, 2019, 2018 and 2017, we incurred $11.9 million, $22.3 million and $14.4 million, respectively, in commitment, participation and fronting fees on letters of credit outstanding and $48.3 million and $18.8 million during the years ended December 31, 2019 and 2018, respectively, in interest on principal borrowings under the Credit Facility, which are recorded as interest expense on the consolidated statements of operations. We did not have principal borrowings under the Credit Facility during 2017 and, therefore, had no associated interest expense.

The Credit Facility contains restrictive covenants including, but not limited to, restrictions on our 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 us to maintain the following two financial ratios: 1) a consolidated leverage ratio, which requires us 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 us 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, 2019, we were in compliance with the financial covenants of the Credit Facility.

As of December 31, 2019, we had $20.0 million in unamortized debt issuance costs associated with the Credit Facility, which are presented as other long-term assets on the consolidated balance sheet.

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, which is presented as losses on purchases or exchanges of debt on the consolidated statement of operations.

Senior Notes

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 October 1, 2017. Our proceeds were used to repay and retire all of our previously outstanding second lien term loans, resulting in a loss on purchases or exchanges of debt of $108.4 million in 2017, and for general corporate purposes. Our obligations under the 2022 Notes are fully and unconditionally guaranteed, jointly and severally, by any of our current and future material subsidiaries. The 2022 Notes are governed by an indenture containing covenants limiting, among other things, our 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. We were in compliance with all applicable covenants under the indenture as of December 31, 2019.

In October 2018, we 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, which commenced May 1, 2019. We used approximately $577.5 million of the $587.2 million 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. We 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. Our obligations under the 2026 Notes are fully and unconditionally guaranteed, jointly and severally, by any of our current and future material subsidiaries. The 2026 Notes are governed by an indenture containing covenants limiting, among other things, our 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. We were in compliance with all applicable covenants under the indenture as of December 31, 2019.

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 up 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 the principal amount for the periods noted) set forth in the table below:

Senior Notes	Redemption Period	Redemption Price
2022 Notes	April 1, 2020 through March 31, 2021	107.500%
2022 Notes	April 1, 2021 through September 30, 2021	105.000%
2022 Notes	October 1, 2021 and thereafter	100.000%
2026 Notes	November 1, 2021 through October 31, 2022	103.500%
2026 Notes	November 1, 2022 through October 31, 2023	102.333%
2026 Notes	November 1, 2023 through October 31, 2024	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 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 we repurchased the notes from the holder.

The Senior Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured debt, and the Senior Notes will rank senior in right of payment to all of 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.

In connection with the issuance and sale of the 2022 Notes, we entered into a registration rights agreement with the initial purchasers. Pursuant to the registration rights agreement, we have agreed to file a registration statement with the United States Securities and Exchange Commission subsequent to an initial public offering of our equity so that the holders may exchange the 2022 Notes for registered notes that have substantially identical terms. In addition, we have agreed to exchange the guarantee related to the 2022 Notes for a registered guarantee having substantially the same terms. We 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 we fail to comply with certain obligations to register the 2022 Notes, then for each 90-day period beginning immediately following such failure, the interest rate on the 2022 Notes will increase by 0.25% per annum, 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%.

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 contributed to us by our Member.

As of December 31, 2019, we had $77.3 million in aggregate principal of the Convertible Notes outstanding. The Convertible Notes mature on March 1, 2021 and are subordinate to the Senior Notes, which rank senior in right of payment. 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 elected to pay interest in kind on each interest payment date from September 2015 through September 2019. 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 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.

Certain embedded features in the Convertible Notes are required to be bifurcated and accounted for as a derivative. The fair value of the embedded derivative was an immaterial amount and $5.0 million as of December 31, 2019 and 2018, respectively.

Debt Maturities

The principal amount of debt maturities for the five years ended after December 31, 2019 and thereafter are as follows:

($ in thousands)	Principal Amount of Debt Securities
2020	$ —
2021[(a)]	118,943
2022	975,000
2023	—
2024[(b)]	1,188,000
Thereafter	600,000
Total	$ 2,881,943

(a) The Convertible Notes due in 2021 include a premium of $41.6 million that is payable upon maturity. The premium is accreted over the scheduled maturity period of the debt.

(b) The Credit Facility maturity date will accelerate to December 30, 2021 if more than $200.0 million of the 2022 Notes are outstanding as of December 30, 2021.

Interest Expense

Interest expense was comprised of the following:

	Years Ended December 31,		
($ in thousands)	2019	2018	2017
Interest expense	$ 208,556	$ 197,251	$ 173,995
Long-term debt accretion expense	16,940	14,665	12,549
Deferred debt issuance cost amortization	6,988	6,717	9,081
Capitalized interest	(123,370)	(126,406)	(122,273)
Total Interest Expense, net	$ 109,114	$ 92,227	$ 73,352

6. Commodity Derivative Instruments

We use commodity derivative instruments to reduce our exposure to fluctuations in future commodity prices and to protect our anticipated operating cash flow against significant market movements or volatility. We do not use commodity derivative instruments for speculative or trading purposes. As of December 31, 2019, our natural gas, oil and NGL derivative instruments consisted of the following types of instruments:

- *Swaps*. We receive a fixed price and pay a variable market price to the counterparty for the hedged commodity.
- *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 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 our sale 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 relative to NYMEX: 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.

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 we have not elected hedge accounting for any of our commodity derivative instruments. 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, and such creditworthiness is subject to periodic review.

The following table sets forth the average volumes per day associated with our outstanding natural gas derivative instruments as of December 31, 2019, the contracted weighted average natural gas prices, the contracted weighted average basis swap spreads and the estimated fair values:

	Average Volume (mmbtu/d)	Weighted Average Prices ($/mmbtu) Swap Strike Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Natural gas:						
Swaps:						$ 319,373
2020	1,512,000	$ 2.72				
2021	835,000	$ 2.60				
2022	530,000	$ 2.52				
2023	100,000	$ 2.70				
Collars:						19,091
2020	140,000		$ 3.09	$ 2.59		
2021	10,000		$ 2.91	$ 2.50		
Three-way collars:						17,013
2021	270,000		$ 2.91	$ 2.50	$ 2.00	
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(30,159)
2020	250,000		$ 3.00			
2021	335,000		$ 3.02			
2022	260,000		$ 3.04			
2023	170,000		$ 3.00			
Basis swaps:						(9,341)
2020	870,000	$ (0.32)				
2021	368,000	$ (0.30)				
2022	5,000	$ 0.11				
Total Estimated Fair Value						$ 315,977

The following table sets forth the average volumes per day associated with our outstanding oil derivative instruments as of December 31, 2019, the contracted weighted average oil prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Swap Strike Price	Sold Call Strike Price	Purchased Put Strike Price	Sold Put Strike Price	Fair Value ($ in thousands)
Oil:						
Swaps:						$ (1,692)
2020	5,700	$ 56.47				
2021	2,000	$ 58.42				
Three-way collars:						613
2021	1,000		$ 65.30	$ 52.50	$ 42.50	
Call options:						(1,982)
2020	4,750		$ 70.00			
2021	3,500		$ 70.00			
Total Estimated Fair Value						$ (3,061)

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of December 31, 2019, the contracted weighted average NGL prices and the estimated fair values:

		Weighted Average Prices ($/bbl)		
	Average Volume (bbl/d)	Swap Strike Price	Sold Call Strike Price	Fair Value ($ in thousands)
NGL:				
Swaps - Propane:				$ 6,016
2020	1,500	$ 30.14		
Call options - Propane:				(36)
2020	3,150		$ 33.60	
Total Estimated Fair Value				$ 5,980

The following tables summarize the fair value of our commodity derivative instruments on a gross basis, the effects of netting assets and liabilities for which the right of offset exists based on master netting agreements and the net amount presented on our consolidated balance sheets as of December 31, 2019 and 2018:

		December 31, 2019		
($ in thousands)	Consolidated Balance Sheet Classification	Gross Recognized Fair Value	Amounts Netted on Balance Sheet	Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative assets	$ 298,113	$ (49,995)	$ 248,118
Natural gas, oil and NGL commodity derivatives	Long-term derivative assets	$ 148,721	$ (77,943)	$ 70,778
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative liabilities	$ 49,995	$ (49,995)	$ —
Natural gas, oil and NGL commodity derivatives	Long-term derivative liabilities	$ 77,943	$ (77,943)	$ —

		December 31, 2018		
($ in thousands)	Consolidated Balance Sheet Classification	Gross Recognized Fair Value	Amounts Netted on Balance Sheet	Net Recognized Fair Value on Balance Sheet
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	Short-term derivative assets	$ 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

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

	Consolidated Statements of	Years Ended December 31,		
($ in thousands)	of Operations Presentation	2019	2018	2017
Natural gas, oil and NGL commodity derivatives	Commodity derivative gain (loss)	$ 441,139	$ (90,881)	$ 212,046

7. Fair Value Measurements

We use 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 our 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, 2019 and 2018. 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 our commodity derivative instruments.

	Fair value measurements at December 31, 2019 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Natural gas, oil and NGL commodity derivatives	$ —	$ 318,896	$ —	$ 318,896
Total	$ —	$ 318,896	$ —	$ 318,896
Derivative liabilities:				
Natural gas, oil and NGL commodity derivatives	$ —	$ —	$ —	$ —
Total	$ —	$ —	$ —	$ —

	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
Total	$ —	$ 22,509	$ —	$ 22,509

Fair Value of Debt

The carrying amounts and estimated fair values of long-term debt as of December 31, 2019 and 2018 are shown in the table below. The fair values were estimated using Level 2 market data inputs. See Note 5 for further information regarding our long-term debt.

	December 31,			
	2019		2018	
($ in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 1,188,000	$ 1,188,000	$ 948,000	$ 948,000
2022 Notes	962,594	969,764	957,993	997,230
2026 Notes	586,330	478,500	584,876	540,000
Convertible Notes	101,752	105,950	86,925	99,567
Total	$ 2,838,676	$ 2,742,214	$ 2,577,794	$ 2,584,797

Fair Value Measurement on a Non-recurring Basis

We 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 our estimates of (i) quantities of natural gas, oil and NGL 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. 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%

8. Related Party Transactions

Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements

In the normal course of our business, we have entered into certain business relationships with entities in which EMG or First Reserve have control or significant influence through their equity investments. These relationships include agreements for the sale of our NGL production and the gathering, processing and transportation of our natural gas and NGL production. The NGL revenues recognized under such agreements were $104.8 million, $79.9 million and $63.8 million during the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019 and 2018, we had accounts receivable – natural gas, oil and NGL sales of $21.2 million and $16.7 million, respectively, due from these purchasers. We also incurred gathering, processing and transportation expenses associated with these agreements of $607.8 million, $463.9 million and $226.8 million during the years ended December 31, 2019, 2018 and 2017, respectively. As of December 31, 2019 and 2018, we had $96.1 million and $85.9 million, respectively, due to companies associated with these agreements, which are presented as other current liabilities on the consolidated balance sheets. For information regarding the credit support requirements due to certain related parties, see Note 9, *Pipeline Commitments*.

Management Services Agreement

In August 2015, we entered into a management services agreement with our Member (Ascent MSA). Under the Ascent MSA, our Member performed any and all general management, administrative and operating services requested by and at our direction. Our Member invoiced us monthly for cash it paid for any costs expended on our behalf in performance of the services. During the year ended December 31, 2017, we incurred expenses of approximately $57.9 million for the services performed under the Ascent MSA, of which $21.5 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, our 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 our direct control (the MSA Assignment). Due to the MSA Assignment, all costs for the services performed under the Ascent MSA are consolidated by us, and therefore, there are no related party expenses in 2019 or 2018 related to the Ascent MSA. As part of the MSA Assignment, our 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

Prior to the UMD Acquisition, UMD was indirectly, majority owned by investment funds controlled by EMG and First Reserve. In May 2017, together with UMD, we 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 us. In August 2017, together with UMD, we acquired natural gas and oil properties and entered into an earn-in agreement, where we could have earned an additional undivided 25% interest in said natural gas and oil properties from UMD by drilling and operating a designated set of wells on the 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.

Convertible Notes

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

9. Commitments and Contingencies

Litigation Matters

We are 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. We continually assess 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. We will continue to monitor the impact that litigation could have on us and will assess the impact of future events. Legal defense costs are accounted for in the period the costs are incurred.

We are defending against certain pending claims, have resolved a number of claims through negotiated settlements and have prevailed in various other lawsuits. Based on management's current assessment, we believe no pending or threatened lawsuit or dispute relating to our business operations is likely to have a material adverse effect on our 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, 2019, we have accrued $9.4 million and associated interest, which is presented as other current liabilities on the consolidated balance sheet.

Environmental Matters

We are 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, we are 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 us.

Commitments

The following table presents our undiscounted commitments under unconditional purchase obligations, excluding any reimbursement from working interest and royalty interest owners, that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2019:

($ in thousands)	Pipeline Commitments	Operating Leases	Other Purchase Obligations	Total
2020	$ 644,121	$ 9,650	$ 1,924	$ 655,695
2021	664,496	2,236	1,971	668,703
2022	668,558	355	625	669,538
2023	669,324	51	—	669,375
2024	661,171	51	—	661,222
Thereafter	6,207,123	—	—	6,207,123
Total	$ 9,514,793	$ 12,343	$ 4,520	$ 9,531,656

Pipeline Commitments

We have entered into certain pipeline capacity commitments with various counterparties in order to facilitate the delivery of our production to market and reduce the impact of possible production curtailments that may arise due to limited capacity. Through these contracts, we are committed to transport minimum daily natural gas or NGL volumes at negotiated rates or pay for any deficiencies. The amounts in the table above represent the gross amounts we are 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, $170.5 million in letters of credit and $288.7 million in surety bonds were issued by us or on our behalf to certain transportation providers as of December 31, 2019.

We are a party to certain firm transportation commitments with related parties, and have provided credit support to such parties as of December 31, 2019 which includes $121.3 million in letters of credit and $161.0 million in surety bonds. For information regarding certain other transactions with related parties, see Note 8, *Gas Gathering, Firm Transportation, Processing and Commodity Sales Agreements*.

Operating Leases

We lease certain equipment and office space as part of our operations. Lease expense related to operating leases totaled $4.6 million, $3.5 million and $1.3 million during the years ended December 31, 2019, 2018 and 2017, respectively. The increase in operating lease expense in 2018 was primarily due to the MSA Assignment, as discussed in Note 8, *Management Services Agreement*. See Note 1, *Adopted and Recently Issued Accounting Pronouncements*, for further discussion of our leases and the expected impact of Topic 842.

We have entered into various drilling rig contracts to utilize drilling services at market-based pricing. Our drilling rig commitments were entered into in the ordinary course of business to ensure rig availability to allow us to execute our business objectives. These commitments are reflected in the table above and associated lease costs will be capitalized to natural gas and oil properties.

10. Other Current Liabilities

Our other current liabilities consisted of the following as of December 31, 2019 and 2018:

	December 31,	
($ in thousands)	2019	2018
Gathering, processing and transportation expense accrual	$ 131,524	$ 106,005
Drilling and completion cost accrual	69,762	124,484
Production and ad valorem taxes accrual	26,494	21,622
Other	53,061	76,469
Total Other Current Liabilities	$ 280,841	$ 328,580

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

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

Capitalized costs related to our natural gas, oil and NGL producing activities are summarized as follows:

($ in thousands)	December 31, 2019	December 31, 2018
Unproved	$ 1,077,966	$ 1,609,036
Proved	7,155,998	5,457,911
Total	8,233,964	7,066,947
Accumulated depreciation, depletion and amortization	(1,876,770)	(1,174,777)
Net Capitalized Costs	$ 6,357,194	$ 5,892,170

Costs incurred in natural gas and oil property acquisition, exploration and development activities are summarized in the table below:

($ in thousands)	Years Ended December 31, 2019	2018	2017
Acquisition costs of properties:			
Proved properties	$ 18,075	$ 675,242	$ 32,261
Unproved properties	218,337	1,146,056	386,789
Total property acquisition costs	236,412	1,821,298	419,050
Exploration costs	8,098	3,404	2,269
Development costs	1,058,883	953,393	683,616
Total	$ 1,303,393	$ 2,778,095	$ 1,104,935

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 our 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, 2019	2018	2017
Revenues, excluding the effects of commodity derivatives	$ 1,979,259	$ 1,687,375	$ 895,361
Lease operating expenses	(72,606)	(50,163)	(35,259)
Gathering, processing and transportation expenses	(856,126)	(658,117)	(341,765)
Production and ad valorem taxes	(34,167)	(23,362)	(14,050)
Exploration expenses	(124,477)	(156,450)	(186,152)
Natural gas and oil depreciation, depletion and amortization	(702,414)	(500,773)	(305,573)
Results of Operations	$ 189,469	$ 298,510	$ 12,562

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 our development plan. Our 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, 2019, 2018 and 2017 were prepared by our 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, 2019, 2018 and 2017 were also independently prepared by Software Integrated Solutions (SIS) (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation. SIS reviewed our type curves for reasonableness and benchmarked them with their own independent analysis from a sampling of our type curves. SIS's results were in reasonable agreement with our results; therefore, they used our 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 our natural gas, oil and NGL reserves is presented in accordance with regulations prescribed by the U.S. Securities and Exchange Commission (SEC).

Subsequent to December 31, 2019, there have been no major discoveries, favorable or otherwise, that are considered to have caused a significant change in our estimated proved reserves at December 31, 2019. The following table sets forth our proved reserves during the periods indicated, all of which are located within the Utica Shale:

	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)[(a)]
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
Extensions, discoveries and other additions	2,609,827	13,967	48,185	2,982,736
Revisions	(565,152)	(3,358)	(7,589)	(630,831)
Purchases of reserves	12,407	—	—	12,407
Sales of reserves	(9,247)	—	—	(9,247)
Production	(638,243)	(4,794)	(8,685)	(719,113)
Proved Reserves at December 31, 2019	8,146,065	48,259	136,016	9,251,715
Proved developed reserves:				
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
December 31, 2019	3,443,414	16,000	61,770	3,910,032
Proved undeveloped reserves:				
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
December 31, 2019	4,702,651	32,259	74,246	5,341,683

(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, 2019, we added approximately 2.983 tcfe in proved reserves through the continued development of our Utica Shale acreage. Revisions of previous estimates included downward revisions of 164.2 bcfe due to lower commodity prices and downward revisions of 466.6 bcfe primarily due to removing PUDs where it was determined development would occur outside of our five-year development plan and type curve updates. As of December 31, 2019, all proved undeveloped locations were in accordance with the SEC five year rule. We added proved reserves through acquisitions of 12.4 bcfe. The unadjusted 12-month average prices used to calculate reserves at December 31, 2019 were $2.58 per mmbtu for natural gas and $55.85 per barrel for oil and condensate.

During the year ended December 31, 2018, we added approximately 2.470 tcfe in proved reserves through the continued development of our 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 were in accordance with the SEC five year rule. We 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, we added approximately 2.392 tcfe in proved reserves through the continued development of our 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 our five year development plan. As of December 31, 2017, all proved undeveloped locations were in accordance with the SEC five year rule. We 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.

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. We have followed these guidelines which are briefly discussed below.

Future cash inflows and future production and development costs as of December 31, 2019, 2018 and 2017 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. We are a disregarded entity for income tax purposes, and therefore, we have 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 our 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 our standardized measure of future net cash flows from our proved natural gas, oil and NGL reserves:

	December 31,		
($ in thousands)	2019	2018	2017
Future cash inflows	$ 25,534,390	$ 26,284,676	$ 12,671,869
Future production costs	(14,026,060)	(11,763,838)	(6,349,919)
Future development costs	(2,887,918)	(2,207,600)	(1,451,743)
Future net cash flows	8,620,412	12,313,238	4,870,207
Discount to present value at 10% annual rate	(4,662,760)	(6,362,658)	(2,573,628)
Standardized Measure of Discounted Future Net Cash Flows	$ 3,957,652	$ 5,950,580	$ 2,296,579

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 our standardized measure of future net cash flows from our proved natural gas, oil and NGL reserves:

	Years Ended December 31,		
($ in thousands)	2019	2018	2017
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Period	$ 5,950,580	$ 2,296,579	$ 856,354
Sales of natural gas, oil and NGL produced, net of production costs	(1,016,360)	(955,733)	(504,287)
Net changes in prices and production costs	(2,589,311)	938,280	185,725
Extensions and discoveries, net of production and development costs	1,240,076	2,002,124	1,212,246
Changes in future development costs	(74,440)	(129,486)	(350,380)
Development costs incurred during period that reduced future development costs	387,391	375,879	116,498
Revisions of previous quantity estimates	(473,097)	196,707	648,911
Purchase of reserves	19,718	816,944	19,278
Sales of reserves	(2,262)	—	(77,916)
Accretion of discount	595,058	229,658	85,635
Changes in production rates and other	(79,701)	179,628	104,515
Standardized Measure of Discounted Future Net Cash Flows, End of Period	$ 3,957,652	$ 5,950,580	$ 2,296,579