MANAGEMENT'S DISCUSSION AND ANALYSIS AND
CONSOLIDATED FINANCIAL STATEMENTS

Ascent Resources Utica Holdings, LLC

As of December 31, 2020 and 2019 and for the Years Ended December 31, 2020, 2019 and 2018.

ASCENT RESOURCES UTICA HOLDINGS, LLC
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

GLOSSARY OF NATURAL GAS, OIL AND NGL TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the natural gas, oil and NGL industry:

"bbl(s)." Barrel(s) as used in reference to crude oil, condensate and NGL. One stock tank barrel equals 42 US gallons liquid volume.

"bbls/d." Barrels of crude oil, condensate or NGL per day.

"bbtu." Billion British thermal units.

"bcf." Billion cubic feet of natural gas.

"bcf/d." Billion cubic feet of natural gas per day.

"bcfe." Billion cubic feet of natural gas equivalent with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"bcfe/d." Billion cubic feet of natural gas equivalent per day.

"btu." British thermal units, a measure of heating value.

"DD&A." Depreciation, depletion and amortization expenses.

"exploratory well." A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, or a service well.

"gross." means:

- In relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalty and overriding royalty interests;
- In relation to wells, the total number of wells in which we have an interest before the deduction of outside working interests, royalty interests and overriding royalty interests; and
- In relation to our interest in a property, the total area in acres of properties in which we have an interest.

"mbbls." Thousands of barrels of crude oil, condensate or NGL.

"*mbbls/d.*" Thousands of barrels of crude oil, condensate or NGL per day.

"mcf." Thousand cubic feet of natural gas.

"mcfe." Thousand cubic feet of natural gas equivalent with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"mmbtu." Million British thermal units.

"mmbtu/d." Million British thermal units per day.

"mmcf." Million cubic feet of natural gas.

"mmcf/d." Million cubic feet of natural gas per day.

"mmcfe." Million cubic feet of natural gas equivalent with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"mmcfe/d." Million cubic feet of natural gas equivalent per day.

"net." means:

- In relation to our interest in production and reserves, our interest (operating and non-operating) share after the deduction of royalty and overriding royalty interests;
- In relation to wells, the number of wells obtained by aggregating our working interest after the deduction of royalty and overriding royalty interests in each of its gross wells;

- In relation to our interest in a property, the total area in acres in which we have an interest multiplied by our working interest in the area after the deduction of royalty and overriding royalty interests; and
- In relation to our interest in leasehold acreage, our gross working interest after the deduction of royalty and overriding royalty interests.

"NGL." Natural gas liquids.

"NYMEX." The New York Mercantile Exchange.

"operator." The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

"proved developed non-producing." Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market accessibility or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

"proved developed producing." Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

"proved undeveloped." or *"PUD(s)."* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

"PV-10." Pre-tax present value of estimated future natural gas, oil and NGL revenues, net of estimated direct expenses, discounted at an annual discount rate of 10%.

"reserves." Estimated remaining quantities of natural gas and oil and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"royalty interest." An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage.

"standardized measure." The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved natural gas and oil reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for the consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved natural gas and oil reserves. However, we are a disregarded entity for income tax purposes and therefore do not estimate future income tax expense.

"tcfe." Trillion cubic feet equivalent, with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

"*unproved properties."* Properties with no proved reserves.

"US." United States of America.

"working interest." An interest in a natural gas and oil lease that gives the owners of the interest the right to drill for and produce natural gas, oil and NGL on the leased acreage and requires the owners of the interest to pay their share of the costs of drilling, completions and production operations.

"WTI." West Texas Intermediate.

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 eighth largest producer of natural gas in the United States in terms of daily production and are focused on acquiring, 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 shale plays. Our largely contiguous development footprint of approximately 337,000 net leasehold acres, including 72,000 mineral 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 6,600 mineral acres that are being developed by third-party operators and 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 NGL from our assets, with the goal of generating top-tier corporate-level returns and sustainable free cash flow in a capital efficient and financially disciplined manner.

2020 Highlights

In October 2020, we closed an exchange (the "Exchange") of $856.7 million in aggregate principal amount of our 10.00% senior notes due 2022 ("2022 Notes") for $537.8 million in aggregate principal amount of second lien term loans due 2025 ("2025 Second Lien Term Loans") and $339.7 million in aggregate principal amount of 9.00% senior unsecured notes due 2027 ("2027 Notes"). As of December 31, 2020, approximately $68.0 million of aggregate principal amount of the 2022 Notes remained outstanding. In December 2020, we issued $300.0 million in aggregate principal amount of 8.25% senior unsecured notes due 2028 ("2028 Notes"). The net proceeds were used to repay a portion of the borrowings outstanding under our senior secured revolving credit facility ("Credit Facility").

Significant financial and operating results for the year ended December 31, 2020 include:

- Capital expenditures incurred decreased 49% to $657.3 million from $1.3 billion in 2019.
- Net production increased 1% to 728.6 bcfe in 2020 from 719.1 bcfe in 2019. Our net daily production for the year ended December 31, 2020 averaged 2.0 bcfe/d and was comprised of approximately 89% natural gas, 3% oil and 8% NGL.
- We spud 60 wells, hydraulically fractured 77 wells and turned-in-line 75 new wells.
- Realized hedging settlement gains were $455.9 million during the year ended December 31, 2020, which improved our average realized sales price by $0.63 per mcfe.

COVID-19 Pandemic

On January 30, 2020, the World Health Organization (the "WHO") announced a global health emergency due to the spread of a novel coronavirus ("COVID-19"), which was classified as a pandemic in March 2020 based on the rapid increase in global exposure. Under the guidance of the WHO and the Centers for Disease Control and Prevention (the "CDC") and in an effort to slow the spread of the virus, many local, state and national governments implemented new laws and regulations which led to a steep decline in the global demand for oil and, to a lesser extent, natural gas. Due to the commodity price environment in 2020, we curtailed certain wells in an effort to optimize revenue in future periods. All such wells have since been turned back to sales; however, further curtailments could be utilized in the future.

In order to safeguard the health of our employees, contractors and the community, while continuing to operate responsibly during the COVID-19 pandemic, we have implemented several precautionary steps which follow the guidance of the WHO, the CDC, and certain state and local governments across our operations. These steps have included allowing a portion of our office staff to work remotely and providing personnel in the field with guidelines designed to decrease the probability of transmission of COVID-19 while maintaining essential operations. We continue to proactively monitor our response to COVID-19 and may have to take further actions in the future if we determine such actions are required by government authorities or are in the best interest of our employees, contractors and the community. Our desire is to do everything possible to protect the health of our people, their families and the community while continuing to operate responsibly and maintain our resiliency.

As the full impact of COVID-19 and the volatility in commodity prices continues to evolve, and, although we are monitoring both closely, we cannot be certain as to the full magnitude that they will have on our future financial condition, liquidity and results of operations.

Well Data

As of December 31, 2020, we held an interest in approximately 912 gross (545 net) productive wells, including 787 gross (545 net) properties in which we held a working interest and 125 gross properties in which we only held an overriding or royalty interest. Of the wells in which we had a working interest, 739 gross (518 net) were classified as productive natural gas wells and 48 gross (27 net) were classified as productive oil wells. We operated approximately 598 gross (528 net) of our productive wells in which we had a working interest. During 2020, we drilled 75 gross (73 net) wells as operator, participated in 3 gross wells and held an overriding or royalty interest in another 6 gross wells drilled by other operators. We operated approximately 99% of our net production volumes in 2020.

Drilling Activity

The following table describes the productive wells we operated or participated in during the years ended December 31, 2020, 2019 and 2018:

	Productive Wells Drilled during the Year Ended December 31,					
	2020		2019		2018	
	Gross	Net	Gross	Net	Gross	Net
Development	78	73	128	112	110	80

As of December 31, 2020, we had 37 gross (34 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, 2020, 2019 or 2018.

Developed and Undeveloped Acreage

The following tables set forth information as of December 31, 2020 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, 2020:

Developed Acres		Undeveloped Acres		Total Acres	
Gross	Net	Gross	Net[(a)]	Gross	Net[(b)]
166,459	130,335	236,351	206,591	402,810	336,926

(a) Approximately 60% 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.

(b) We own royalty interests in approximately 78,000 mineral acres, including 6,600 mineral acres where development is controlled by third-party operators.

The following table sets forth the number of total undeveloped acres as of December 31, 2020 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
2021	16,979	15,059
2022	34,696	33,382
2023	19,419	18,202
2024	13,164	12,636
2025 and thereafter	3,756	3,584
Total	88,014	82,863

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, 2020:

	Natural Gas (bbtu)	Ethane (mbbls)
2021	104,781	1,405
2022	104,781	1,152
2023	104,781	962
2024	62,363	965
2025	46,746	962
2026 - 2029	151,891	3,852
Total	575,343	9,298

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:

	Year Ended December 31, 2020	2019	2018
Net Production Volumes:			
Natural gas (mmcf)	646,982	638,243	457,747
Oil (mbbls)	4,291	4,794	2,262
NGL (mbbls)	9,304	8,685	3,974
Natural Gas Equivalent (mmcfe)	728,553	719,113	495,168
Average Sales Prices:			
Natural gas ($/mcf)	$ 1.95	$ 2.49	$ 3.16
Oil ($/bbl)	$ 32.33	$ 50.38	$ 59.15
NGL ($/bbl)	$ 12.71	$ 17.11	$ 27.48
Natural Gas Equivalent ($/mcfe)	$ 2.08	$ 2.75	$ 3.41
Settlements of commodity derivatives ($/mcfe)	0.63	0.27	(0.11)
Average sales price, after effects of settled derivatives ($/mcfe)	$ 2.71	$ 3.02	$ 3.30
Operating Expenses ($/mcfe):			
Lease operating expenses	$ 0.11	$ 0.10	$ 0.10
Gathering, processing and transportation expenses	$ 1.26	$ 1.19	$ 1.33

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, 2020:

	December 31, 2020 Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)
Proved developed reserves[a]	3,830,924	16,273	57,831	4,275,548
Proved undeveloped reserves	4,242,110	26,340	52,530	4,715,327
Total	8,073,034	42,613	110,361	8,990,875

(a) Approximately 195.2 bcfe, or 5%, of our proved developed reserves were proved developed non-producing.

The table below sets forth information as of December 31, 2020, with respect to our estimated proved reserves, 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, 2020. 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, 2020. The prices used in our reserve reports were $1.99 per mmbtu of natural gas and $39.54 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, 2020. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to 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, 2020.

	December 31, 2020		
($ in thousands)	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$ 1,716,772	$ 1,070,706	$ 2,787,478
PV-10	$ 1,088,166	$ 176,934	$ 1,265,100
Standardized measure[(a)]			$ 1,265,100

(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, 2020, our estimated proved reserves included approximately 4.715 tcfe of reserves classified as proved undeveloped, compared to approximately 5.342 tcfe as of December 31, 2019. The table below is a summary of changes in our PUDs for 2020:

	Total (mmcfe)
Proved undeveloped reserves at December 31, 2019	5,341,683
Extensions, discoveries and other additions	788,962
Revisions	(427,975)
Conversions into proved developed reserves	(987,343)
Proved undeveloped reserves at December 31, 2020	4,715,327

As of December 31, 2020, there were no PUDs that had remained undeveloped for five years or more. Our proved undeveloped extensions and discoveries of approximately 789.0 bcfe of reserves resulted from the continued development of our Utica Shale acreage. Downward revisions of previous PUDs estimates included revisions of 258.6 bcfe resulting from removing PUDs where it was determined development would occur outside of our five-year development plan and other revisions to our PUDs of 169.4 bcfe primarily due to type curve revisions. In 2020, we invested $403.6 million to convert 987.3 bcfe from proved undeveloped reserves to proved developed reserves.

The future net revenues attributable to our estimated PUDs of $1.1 billion as of December 31, 2020, and associated PV-10 of $176.9 million, have been calculated assuming that we will expend approximately $1.8 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

In 2020, our proved reserve estimates were prepared by our new, independent reserves engineers, Netherland, Sewell & Associates, Inc. (“NSAI”). Each of Robert C. Barg and William J. Knights, the technical persons at NSAI primarily responsible for preparing the estimates presented herein, meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Mr. Barg, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 1989 and has over six years of prior industry experience. He is an active member of the Society of Petroleum Engineers. Mr. Knights, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 1991 and has over 10 years of prior industry experience. Neither Mr. Barg nor Mr. Knights owns an interest in any of our properties, and neither is 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 Utica Shale. 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 Senior 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 23 years of reservoir estimation and operations experience, and our engineering and geoscience staff have an average of approximately 14 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, 2020, 2019 and 2018 is derived from the audited consolidated financial statements. The financial data included may not be indicative of our future results.

($ in thousands)	Year Ended December 31, 2020	2019	2018
Statements of operations data:			
Revenues:			
Natural gas	$ 1,258,594	$ 1,589,099	$ 1,444,368
Oil	138,723	241,521	133,786
NGL	118,224	148,639	109,221
Commodity derivative (loss) gain	(19,167)	441,139	(90,881)
Total Revenues	1,496,374	2,420,398	1,596,494
Operating Expenses:			
Lease operating expenses	78,430	72,606	50,163
Gathering, processing and transportation expenses	919,986	856,126	658,117
Production and ad valorem taxes	37,495	34,167	23,362
Exploration expenses	104,230	124,477	156,450
General and administrative expenses, including related party	63,825	61,027	63,794
Acquisition expenses	—	—	9,407
Natural gas and oil depreciation, depletion and amortization	733,450	702,414	500,773
Depreciation and amortization of other assets	3,568	3,239	3,912
Total Operating Expenses	1,940,984	1,854,056	1,465,978
(Loss) Income from Operations	(444,610)	566,342	130,516
Other (Expense) Income:			
Interest expense, net	(134,213)	(109,114)	(92,227)
Change in fair value of contingent payment right	(6,518)	—	—
Change in fair value of embedded derivative	—	5,026	18,865
Losses on purchases or exchanges of debt	(6,037)	—	(62,233)
Other income	1,867	3,711	683
Total Other Expense	(144,901)	(100,377)	(134,912)
Net (Loss) Income	$ (589,511)	$ 465,965	$ (4,396)
Balance sheets data (at period end):			
Cash and cash equivalents	$ 8,843	$ 7,346	$ 11,030
Total assets	$ 6,471,849	$ 7,010,418	$ 6,486,822
Current portion of long-term debt, net	$ 12,498	$ —	$ —
Total long-term debt, net	$ 2,707,382	$ 2,838,676	$ 2,582,820
Total liabilities	$ 3,369,854	$ 3,329,035	$ 3,271,725
Total liabilities and Member's equity	$ 6,471,849	$ 7,010,418	$ 6,486,822

Liquidity and Capital Resources

Liquidity Overview

The drilling, completion and production of our natural gas and oil properties are capital intensive activities that require access to significant capital. We continually evaluate our capital needs and compare them to our capital resources. Our primary sources of funds are internally generated cash flows from operations, draws on our Credit Facility and proceeds from the issuance of debt, and historically they have included equity contributions from our Parent. Based on existing market conditions and our expected liquidity needs, among other factors, we intend to use a portion of our cash flows from operations and any proceeds from divestitures to repay portions of our indebtedness. Additionally, we may use securities offerings to repay debt prior to scheduled maturities, and we may seek opportunities to refinance all or a portion of our indebtedness, including through cash purchases, exchanges, open market purchases, privately negotiated transactions or otherwise, as demonstrated through our October and December 2020 debt transactions.

See Note 4, *Senior Notes*, of the notes to our consolidated financial statements included in this report for further discussion of our recent debt transactions which significantly improved our near-term debt maturity profile.

As of December 31, 2020, we had a cash balance of $8.8 million and availability under our Credit Facility of $748.3 million. In November 2020, the borrowing base under the Credit Facility was reaffirmed at $1.85 billion. 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.

Sources and Uses of Funds

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

	Year Ended December 31,		
($ in thousands)	2020	2019	2018
Cash provided by operating activities	$ 773,021	$ 1,140,118	$ 688,733
Proceeds from issuance of long-term debt	300,000	—	587,166
Proceeds from the Exchange	20,000	—	—
Proceeds from Credit Facility borrowings, net of repayments	—	240,000	948,000
Proceeds from divestitures of natural gas and oil properties	—	12,474	6,564
Contributions from Member	—	—	567,647
Other	1,557	—	—
Total Sources of Cash and Cash Equivalents	$ 1,094,578	$ 1,392,592	$ 2,798,110

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

	Year Ended December 31,		
($ in thousands)	2020	2019	2018
Natural Gas and Oil Expenditures:			
Drilling and completion costs	$ 557,656	$ 1,096,627	$ 875,810
Acquisitions of natural gas and oil properties	71,102	163,220	1,313,342
Interest capitalized[(a)]	82,208	123,370	126,406
Total Natural Gas and Oil Expenditures	710,966	1,383,217	2,315,558
Other Uses of Cash and Cash Equivalents:			
Repayment of Credit Facility, net of borrowings	235,000	—	—
Repayment of long-term debt	138,764	—	525,000
Additions to other property and equipment	1,509	3,547	1,512
Cash paid for debt issuance costs	6,842	9,512	11,725
Cash paid for debt prepayment costs	—	—	52,500
Total Other	382,115	13,059	590,737
Total Uses of Cash and Cash Equivalents	$ 1,093,081	$ 1,396,276	$ 2,906,295

(a) Interest is capitalized on significant investments in active unproved properties and wells in process.

Our primary source of funds is net cash flow provided by operating activities, which was approximately $773.0 million, $1.14 billion and $688.7 million for 2020, 2019 and 2018, respectively. The decrease in operating cash flow in 2020 compared to 2019 was primarily the result of decreases in the average realized sales price of natural gas, oil and NGL, which were partially offset by the settlement of commodity derivatives. 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 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" and, together with the CNX and Hess Acquisition, the "2018 Acquisitions").

In October 2020, in connection with the Exchange, we issued 2025 Second Lien Term Loans, 2027 Notes and equity of our Parent to certain existing equity holders and their designated affiliates in exchange for an aggregate contribution of $20.0 million in cash. The proceeds were used to pay fees for the Exchange and to repay a portion of the borrowings outstanding under the Credit Facility. In December 2020, we issued $300.0 million in aggregate principal amount of our 2028 Notes and used the net proceeds to repay a portion of the borrowings outstanding under the Credit Facility. Additionally, during 2020, we paid $103.4 million to repurchase a portion of our outstanding Convertible Notes and $35.4 million to repurchase a portion of our outstanding 2022 Notes.

In October 2018, we issued $600.0 million in aggregate principal amount of our 2026 Notes (defined below). We used approximately $577.5 million of the net proceeds to redeem $525.0 million in aggregate principal amount of the 2022 Notes, and we used the remaining net proceeds to repay borrowings under the Credit Facility. In 2018, we also received $567.6 million in net cash contributions from equity capital raised by our Parent to partially fund the 2018 Acquisitions.

Our cash drilling and completion costs were $557.7 million, $1.10 billion and $875.8 million in 2020, 2019 and 2018, respectively. The decrease in drilling and completion costs in 2020 was the result of us drilling and completing fewer wells as well as reduced costs per lateral foot due to increased completion stages per day and improved drilling cycle times. We drilled 75 new wells in 2020 compared to 126 new wells in 2019 and 102 new wells in 2018.

We spent cash of $71.1 million, $163.2 million and $284.0 million in 2020, 2019 and 2018, 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 & Hess Acquisition and $263.2 million for 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.

Certain Indebtedness

Credit Facility

Our Credit Facility matures on April 1, 2024, and as of December 31, 2020, it had a fully committed borrowing base of $1.85 billion, of which $250.0 million was authorized for letters of credit. 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 May 1 and November 1 of each year primarily based on the estimated value and future net cash flows of our proved natural gas, oil and NGL reserves and our commodity derivative positions, as determined by lenders under the Credit Facility at their discretion. If the commodity price environment declines over an extended period, it may in the future lead to a reduction in the borrowing base of our Credit Facility. We do not believe that any such reductions would have a significant impact on our ability to service our debt and fund our drilling program and related operations. As of December 31, 2020, we had $953.0 million of borrowings outstanding and $148.7 million of letters of credit issued under the Credit Facility.

As of December 31, 2020, we were in compliance with all applicable financial covenants under the Credit Facility. Our ability to comply with financial covenants in future periods depends, among other things, on the success of our development program and other factors beyond our control, such as market demand and prices for natural gas, oil and NGL. See Note 4, *Credit Facility*, of the notes to our consolidated financial statements included in this report for further discussion of the terms of the Credit Facility.

Second Lien Term Loans

In October 2020, we issued $549.8 million in aggregate principal amount of 2025 Second Lien Term Loans. The 2025 Second Lien Term Loans are due on November 1, 2025, and interest is payable at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor, on January 13, April 13, July 13 and October 13 of each year. The 2025 Second Lien Term Loans are secured by second liens on substantially all of our assets, including our natural gas and oil properties. As of December 31, 2020, we had $549.8 million in aggregate principal amount of 2025 Second Lien Term Loans outstanding, and we were in compliance with all applicable covenants under the 2025 Second Lien Term Loans.

Senior Notes

2022 Notes. In April 2017, we issued $1.5 billion in aggregate principal amount of 2022 Notes in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act of 1933 (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. In 2018, we redeemed $525.0 million of the aggregate principal amount of the 2022 Notes at a redemption price equal to 110.00% of the principal thereof, plus accrued and unpaid interest. In October 2020, we completed the Exchange, which resulted in $856.7 million of aggregate principal amount of 2022 Notes being exchanged for a combination of 2025 Second Lien Term Loans and 2027 Notes. As of December 31, 2020, after giving effect to the Exchange and prior open market repurchases and redemptions, we had $68.0 million in aggregate principal amount of the 2022 Notes outstanding.

2026 Notes. In October 2018, we issued $600.0 million in aggregate principal amount of 7.00% senior unsecured notes due 2026 ("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. As of December 31, 2020, we had $600.0 million in aggregate principal amount of the 2026 Notes outstanding.

2027 Notes. In October 2020, we issued $348.3 million in aggregate principal amount of 2027 Notes. The 2027 Notes are due on November 1, 2027, and interest is payable at an annual rate of 9.00% on May 1 and November 1 of each year, beginning with May 1, 2021. As of December 31, 2020, we had $348.3 million in aggregate principal amount of the 2027 Notes outstanding.

The 2027 Notes also contain a contingent payment right which entitles the holders to receive a fixed amount of cash or equity, ranging from 30% to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if certain triggering events occur. The contingent payment right is required to be bifurcated, and as of December 31, 2020, the estimated fair value was $65.3 million. See Note 4, *Senior Notes*, and Note 6, *Contingent Payment Right*, of the notes to our consolidated financial statements included in this report for further discussion of the contingent payment right.

2028 Notes. In December 2020, we issued $300.0 million in aggregate principal amount of 2028 Notes in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2028 Notes are due on December 31, 2028, and interest is payable at an annual rate of 8.25% on February 1 and August 1 of each year, beginning with August 1, 2021. The net proceeds were used to repay a portion of the borrowings outstanding under the Credit Facility. As of December 31, 2020, we had $300.0 million in aggregate principal amount of the 2028 Notes outstanding.

The 2022 Notes, 2026 Notes, 2027 Notes and 2028 Notes (together, 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 are effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness. Our obligations under the Senior Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. As of December 31, 2020, we were in compliance with all applicable covenants of the indentures governing the Senior Notes.

Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the Senior Notes, excluding the 2022 Notes, at a price of 101.00%, plus accrued and unpaid interest. The Senior Notes each have certain conditions set forth under which they may be redeemed prior to maturity. See Note 4, *Senior Notes*, of the notes to our consolidated financial statements included in this report for further discussion of the terms and early redemptions of the Senior 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. In 2020, we repurchased an additional $69.0 million in aggregate principal amount of the outstanding Convertible Notes for $103.4 million in cash, plus accrued and unpaid interest, and recorded a $2.7 million loss, including the write-off of debt issuance costs, discounts and premiums. As of December 31, 2020, we had $8.3 million in aggregate principal of the Convertible Notes outstanding, and the carrying value of the Convertible Notes, including the portion of the premium that has been accreted, was $12.5 million. The remaining Convertible Notes matured on March 1, 2021 and were redeemed at 153.8% of the outstanding principal value, plus accrued and unpaid interest up to, but not including, the maturity date, as provided in the indenture for $13.1 million in cash.

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, 2020:

	Payments Due by Period				
($ in thousands)	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Long-term debt:					
Principal[a]	$ 2,831,889	$ 12,781	$ 67,992	$ 1,502,822	$ 1,248,294
Interest	1,075,151	188,958	377,873	319,065	189,255
Operating lease commitments	17,750	10,730	6,969	51	—
Pipeline commitments	8,756,037	659,358	1,323,503	1,296,221	5,476,955
Other	10,572	3,435	2,312	—	4,825
Total	$ 12,691,399	$ 875,262	$ 1,778,649	$ 3,118,159	$ 6,919,329

(a) The Convertible Notes due in 2021 included a premium of $4.5 million that was payable upon maturity. The premium was accreted over the scheduled maturity period of the debt. The Convertible Notes matured on March 1, 2021.

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.

Critical Accounting Policies and Estimates

Our consolidated financial statements are prepared in accordance with 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 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.

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 our properties 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. Additionally, 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 of undeveloped leases and the costs incurred to acquire, drill and complete productive wells and development wells 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, 2020, 2019 or 2018. The application of the successful efforts method of accounting requires management's 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, 2020, 2019 or 2018. 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. If natural gas, oil and NGL prices decrease or drilling efforts are unsuccessful, we may be required to record an impairment.

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. 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 evaluate the carrying amount of our proved natural gas and oil properties for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. As of December 31, 2020, no such event or change in circumstances had occurred.

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.

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, our anticipated drilling program, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2020, 2019 and 2018, we recorded impairments of $100.2 million, $115.8 million and $153.0 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

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.

Derivatives

We 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. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. All commodity derivative instruments, other than those that meet the normal purchase and normal sale scope exception, are recorded at fair market value in accordance with GAAP and are included in our consolidated balance sheets as assets or liabilities. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized on our statements of operations within operating revenues as commodity derivative (loss) gain. 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.

Our derivative instruments expose us to counterparty credit risk, which arises due to the risk of loss from counterparties not performing under the terms of a derivative contract. To minimize such risk, we only enter into derivative contracts with counterparties that we determine are creditworthy, which includes performing both quantitative and qualitative assessments of these counterparties, based on their credit ratings and credit default swap rates where applicable. Additionally, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty. 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 5 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.

Results of Operations

Year Ended December 31, 2020 Compared to 2019

Revenues. The following table sets forth certain information for the periods indicated regarding our revenues; average sales prices received; and net production volumes:

	Year Ended December 31,		Variance	
	2020	2019	Amount	Percent
Revenues ($ in thousands):				
Natural gas	$ 1,258,594	$ 1,589,099	$ (330,505)	(21)%
Oil	138,723	241,521	(102,798)	(43)%
NGL	118,224	148,639	(30,415)	(20)%
Total Revenues, before effects of commodity derivatives	$ 1,515,541	$ 1,979,259	$ (463,718)	(23)%
Average Sales Prices:				
Natural gas ($/mcf)	$ 1.95	$ 2.49	$ (0.54)	(22)%
Oil ($/bbl)	$ 32.33	$ 50.38	$ (18.05)	(36)%
NGL ($/bbl)	$ 12.71	$ 17.11	$ (4.40)	(26)%
Natural Gas Equivalent ($/mcfe)	$ 2.08	$ 2.75	$ (0.67)	(24)%
Settlements of commodity derivatives ($/mcfe)	0.63	0.27	0.36	133 %
Average sales price, after effects of settled derivatives ($/mcfe)	$ 2.71	$ 3.02	$ (0.31)	(10)%
Net Production Volumes:				
Natural gas (mmcf)	646,982	638,243	8,739	1 %
Oil (mbbls)	4,291	4,794	(503)	(10)%
NGL (mbbls)	9,304	8,685	619	7 %
Natural Gas Equivalent (mmcfe)	728,553	719,113	9,440	1 %
Average Daily Net Production Volumes:				
Natural gas (mmcf/d)	1,768	1,749	19	1 %
Oil (mbbls/d)	12	13	(1)	(8)%
NGL (mbbls/d)	25	24	1	4 %
Natural Gas Equivalent (mmcfe/d)	1,991	1,970	21	1 %

The $463.7 million decrease in natural gas, oil and NGL revenues (excluding the effects of derivatives) was primarily due to a significant decrease in commodity prices. Commodity prices fluctuate in response to changes in supply and demand, market uncertainty and a variety of other factors beyond our control.

A change in commodity prices has a direct impact on our sales and cash flows. The following table illustrates the effects of an increase or decrease in commodity prices on our sales and cash flows, before the effects of derivatives, assuming our production levels for the year ended December 31, 2020 remained constant:

($ in thousands)	Volumes	Price Fluctuation	Effect on Sales and Cash Flows
Commodity:			
Natural Gas (mmcf)	646,982	$ 0.10	$ 64,698
Oil (mbbls)	4,291	$ 1.00	$ 4,291
NGL (mbbls)	9,304	$ 1.00	$ 9,304

Impact of Commodity Derivative Instruments. We use commodity derivative instruments to mitigate our exposure to fluctuations in future commodity prices in order to protect our anticipated operating cash flow against significant market movements or volatility. The following table sets forth the settlements of our derivative instruments and the change in fair value for the periods indicated:

($ in thousands)	Year Ended December 31, 2020	Year Ended December 31, 2019
Net Cash Received on Settlements of Commodity Derivatives:		
Natural Gas	$ 402,391	$ 164,606
Oil	48,273	1,349
NGL	5,196	25,727
Total Net Cash Received on Settlements of Commodity Derivatives	455,860	191,682
Change in Fair Value of Commodity Derivatives:		
Natural Gas	(472,299)	303,493
Oil	4,252	(45,101)
NGL	(6,980)	(8,935)
Total Change in Fair Value of Commodity Derivatives	(475,027)	249,457
Total (Loss) Gain on Commodity Derivatives	$ (19,167)	$ 441,139

Operating Expenses. The following table sets forth our operating expenses and costs per mcfe:

	Year Ended December 31, 2020	Year Ended December 31, 2019	Variance Amount	Variance Percent
Operating Expenses ($ in thousands):				
Lease operating expenses	$ 78,430	$ 72,606	$ 5,824	8 %
Gathering, processing and transportation expenses	$ 919,986	$ 856,126	$ 63,860	7 %
Production and ad valorem taxes	$ 37,495	$ 34,167	$ 3,328	10 %
Exploration expenses	$ 104,230	$ 124,477	$ (20,247)	(16)%
General and administrative expenses	$ 63,825	$ 61,027	$ 2,798	5 %
Natural gas and oil depreciation, depletion and amortization	$ 733,450	$ 702,414	$ 31,036	4 %
Depreciation and amortization of other assets	$ 3,568	$ 3,239	$ 329	10 %
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.11	$ 0.10	$ 0.01	10 %
Gathering, processing and transportation expenses	$ 1.26	$ 1.19	$ 0.07	6 %
Production and ad valorem taxes	$ 0.05	$ 0.05	$ —	— %
General and administrative expenses	$ 0.09	$ 0.08	$ 0.01	13 %
Natural gas and oil depreciation, depletion and amortization	$ 1.01	$ 0.98	$ 0.03	3 %
Depreciation and amortization of other assets	$ —	$ —	$ —	— %

- Lease operating expenses increased as a result of an increase in producing wells and an increase in compression costs during 2020 compared to 2019.

- Gathering, processing and transportation expenses per mcfe increased primarily as a result of an increase in firm transportation and voluntary marketing curtailments during 2020 compared to 2019.

- Production taxes were $21.1 million and $21.0 million in 2020 and 2019, 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 2020 and 2019, respectively. Ad valorem taxes were $16.4 million and $13.2 million in 2020 and 2019, respectively. Ad valorem taxes have increased due to an increase in producing wells in 2020; however, this was partially offset by lower appraised values as determined by the state due to a decrease in natural gas and oil prices.

- Exploration expense was primarily driven by unproved impairments of $100.2 million and $115.8 million in 2020 and 2019, respectively, for 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 increased primarily due to $5.6 million of accrued non-recurring legal expenses during 2020, which was partially offset by corporate efficiencies.

- Natural gas and oil DD&A per mcfe increased due to a 3% decrease in total proved reserves as of December 31, 2020, compared to December 31, 2019.

Interest Expense. Interest expense was $134.2 million and $109.1 million in 2020 and 2019, respectively, detailed as follows along with our weighted average debt outstanding:

($ in thousands)	Year Ended December 31, 2020	Year Ended December 31, 2019
Interest expense on Credit Facility	$ 45,969	$ 60,272
Interest expense on 2025 Second Lien Term Loans	12,219	—
Interest expense on 2022 Notes	74,878	97,500
Interest expense on 2026 Notes	42,011	42,002
Interest expense on 2027 Notes	6,791	—
Interest expense on 2028 Notes	963	—
Interest expense on Convertible Notes	4,026	4,906
Loss on interest rate derivatives	790	—
Amortization of debt discounts, premium and issuance costs	25,186	23,928
Other	3,588	3,876
Capitalized interest	(82,208)	(123,370)
Total Interest Expense, net	$ 134,213	$ 109,114
Weighted Average Debt Outstanding:		
Credit Facility	$ 1,230,855	$ 1,119,518
2025 Second Lien Term Loans	120,180	—
2022 Notes	746,552	975,000
2026 Notes	600,000	600,000
2027 Notes	76,130	—
2028 Notes	12,295	—
Convertible Notes	61,744	75,334
Weighted Average Debt Outstanding	$ 2,847,756	$ 2,769,852

The increase in interest expense in 2020 compared to 2019 was primarily due to reduced capitalized interest caused by a decrease in our development activity and a decrease in our weighted average borrowing rate, which was primarily due to a decrease in the 1-month LIBOR in 2020 compared to 2019. The decrease in the 1-month LIBOR also significantly reduced interest expense on the Credit Facility.

Losses on Purchases or Exchanges of Debt. We recognized a net loss on purchases or exchanges of debt of $6.0 million in 2020 primarily due to $17.7 million of fees related to the Exchange of 2022 Notes, which was accounted for as a modification of debt. We also recognized a $2.7 million loss on the repurchase of a portion of our Convertible Notes in 2020. This was partially offset by our repurchase of a portion of our 2022 Notes, which resulted in a $14.3 million gain. See Note 4, *Senior Notes* and *Convertible Notes*, of the notes to our consolidated financial statements included in this report for further discussion of our repurchases and the Exchange of debt.

Year Ended December 31, 2019 Compared to 2018

Revenues. The following table sets forth certain information for the periods indicated regarding our revenues; average sales prices received; and net production volumes:

	Year Ended December 31,		Variance	
	2019	2018	Amount	Percent
Revenues ($ in thousands):				
Natural gas	$ 1,589,099	$ 1,444,368	$ 144,731	10 %
Oil	241,521	133,786	107,735	81 %
NGL	148,639	109,221	39,418	36 %
Total Revenues, before effects of commodity derivatives	$ 1,979,259	$ 1,687,375	$ 291,884	17 %
Average Sales Prices:				
Natural gas ($/mcf)	$ 2.49	$ 3.16	$ (0.67)	(21)%
Oil ($/bbl)	$ 50.38	$ 59.15	$ (8.77)	(15)%
NGL ($/bbl)	$ 17.11	$ 27.48	$ (10.37)	(38)%
Natural Gas Equivalent ($/mcfe)	$ 2.75	$ 3.41	$ (0.66)	(19)%
Settlements of commodity derivatives ($/mcfe)	0.27	(0.11)	0.38	(345)%
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.02	$ 3.30	$ (0.28)	(8)%
Net Production Volumes:				
Natural gas (mmcf)	638,243	457,747	180,496	39 %
Oil (mbbls)	4,794	2,262	2,532	112 %
NGL (mbbls)	8,685	3,974	4,711	119 %
Natural Gas Equivalent (mmcfe)	719,113	495,168	223,945	45 %
Average Daily Net Production Volumes:				
Natural gas (mmcf/d)	1,749	1,254	495	39 %
Oil (mbbls/d)	13	6	7	117 %
NGL (mbbls/d)	24	11	13	118 %
Natural Gas Equivalent (mmcfe/d)	1,970	1,357	613	45 %

The $291.9 million increase in natural gas, oil and NGL revenues (excluding the effects of derivatives) was primarily due to a significant increase in production as a result of our drilling and completions activity and the completion of acquisitions in the third quarter of 2018, partially offset by decreases in commodity prices.

Impact of Commodity Derivative Instruments. We use commodity derivative instruments to mitigate our exposure to fluctuations in future commodity prices in order to protect our anticipated operating cash flow against significant market movements or volatility. The following table sets forth the settlements of our derivative instruments and the change in fair value for the periods indicated:

($ in thousands)	Year Ended December 31, 2019	2018
Net Cash Received (Paid) on Settlements of Commodity Derivatives:		
Natural Gas	$ 164,606	$ (42,926)
Oil	1,349	(17,077)
NGL	25,727	3,260
Total Net Cash Received (Paid) on Settlements of Commodity Derivatives	191,682	(56,743)
Change in Fair Value of Commodity Derivatives:		
Natural Gas	303,493	(103,919)
Oil	(45,101)	54,856
NGL	(8,935)	14,925
Total Change in Fair Value of Commodity Derivatives	249,457	(34,138)
Total Gain (Loss) on Commodity Derivatives	$ 441,139	$ (90,881)

Operating Expenses. The following table sets forth our operating expenses and costs per mcfe:

	Year Ended December 31,		Variance	
	2019	2018	Amount	Percent
Operating Expenses ($ in thousands):				
Lease operating expenses	$ 72,606	$ 50,163	$ 22,443	45 %
Gathering, processing and transportation expenses	$ 856,126	$ 658,117	$ 198,009	30 %
Production and ad valorem taxes	$ 34,167	$ 23,362	$ 10,805	46 %
Exploration expenses	$ 124,477	$ 156,450	$ (31,973)	(20)%
General and administrative expenses	$ 61,027	$ 63,794	$ (2,767)	(4)%
Acquisition expenses	$ —	$ 9,407	$ (9,407)	(100)%
Natural gas and oil depreciation, depletion and amortization	$ 702,414	$ 500,773	$ 201,641	40 %
Depreciation and amortization of other assets	$ 3,239	$ 3,912	$ (673)	(17)%
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.10	$ 0.10	$ —	— %
Gathering, processing and transportation expenses	$ 1.19	$ 1.33	$ (0.14)	(11)%
Production and ad valorem taxes	$ 0.05	$ 0.05	$ —	— %
General and administrative expenses	$ 0.08	$ 0.13	$ (0.05)	(38)%
Natural gas and oil depreciation, depletion and amortization	$ 0.98	$ 1.01	$ (0.03)	(3)%
Depreciation and amortization of other assets	$ —	$ 0.01	$ (0.01)	(100)%

- Total lease operating expenses increased as a result of an increase in producing wells during 2019 compared to 2018.
- Gathering, processing and transportation expenses decreased per mcfe primarily as a result of increased production levels in 2019 compared to 2018 which allowed us to optimize our firm transportation commitments.
- Production taxes 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 increased due to an increase in producing wells in 2019.
- Exploration expense was primarily driven by unproved impairments of $115.8 million and $153.0 million in 2019 and 2018, respectively, for unproved natural gas and oil properties for which the leases are expected to expire.

- General and administrative expenses per mcfe decreased primarily due to increased production in 2019 and $9.4 million of accrued non-recurring legal expenses during 2018.

- Acquisition expenses were incurred in 2018 in connection with the closing of the CNX and Hess Acquisition and the UMD Acquisition. 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.

- DD&A of natural gas and oil properties per mcfe decreased as a result of a 21% increase in total proved reserves from 2018 to 2019.

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:

	Year 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 2022 Notes. See Note 4, *Senior Notes*, of the notes to our consolidated financial statements included in this report for further discussion of our repurchases and exchanges of debt.

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 as well as how we view and manage our exposure to such 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.

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. During 2020, 2019 and 2018, the average daily Henry Hub spot market price of natural gas was $1.99 per mmbtu, $2.51 per mmbtu and $3.12 per mmbtu, respectively, and the average daily West Texas Intermediate oil price was $39.34 per bbl, $57.04 per bbl and $64.90 per bbl, respectively. Approximately 90% of our December 31, 2020 proved reserves were natural gas; therefore, changes in realized natural gas pricing will affect us more than changes in realized oil or NGL pricing.

We use 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. These contracts are financial instruments and do not require or allow for physical delivery of the hedged commodity. We do not use derivative instruments for speculative or trading purposes. Under the Credit Facility agreement, we are permitted to hedge up to 90% of our forecasted production for any month during the next 36 months. Additionally, we may enter into commodity derivative contracts with terms greater than 36 months, and for no longer than 66 months, for up to 80% of the forecasted production from our proved reserves for any month. As of December 31, 2020, approximately 1,303,000 mmbtu/d of our projected natural gas production for 2021 were hedged at a weighted average floor price of $2.54 per mmbtu, and approximately 1,178,000 mmbtu/d of our projected natural gas production for 2022 were hedged at a weighted average floor price of $2.51 per mmbtu, excluding the sold puts on our three-way collars. Additionally, as of December 31, 2020, approximately 2,200 bbl/d of our projected oil production for 2021 were hedged at a weighted average floor price of $50.44 per bbl. Our open hedge positions at December 31, 2020 had maturities extending through December 2024. Additionally we have basis swaps to mitigate portions of our basis exposure. See Note 5 of the notes to our consolidated financial statements included in this report for a summary of our commodity hedge position as of December 31, 2020.

The fair value of our commodity 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 commodity derivative instruments due to a hypothetical 10% change in future prices as of December 31, 2020. 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	$ (331,127)	$ 315,076
Oil	$ (4,568)	$ 4,255
NGL	$ (1,906)	$ 1,906

All derivative instruments, other than those that meet the normal purchase and normal sale scope exception, are recorded at fair market value in accordance with GAAP and are included in our consolidated balance sheets as assets or liabilities. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; therefore, all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations within operating revenues as commodity derivative (loss) gain.

Although mark-to-market adjustments of derivative instruments cause earnings volatility, our cash flows are only impacted when the associated derivative contracts are settled or are monetized prior to settlement by making or receiving payments to or from the counterparty. We expect continued volatility in the fair value of our derivative instruments. At December 31, 2020, the estimated fair value of our commodity derivative positions was a net liability of $156.1 million comprised of current and long-term assets and liabilities.

By removing price volatility from a portion of our future expected production, we have mitigated, but not eliminated, the potential negative effects of changing prices on our operating cash flows for those periods. While mitigating the negative effects of falling commodity prices, these derivative contracts also limit the benefits we receive from the increases in commodity prices above the fixed hedge ceiling prices.

Counterparty Credit Risk

Our derivative instruments expose us to counterparty credit risk, which arises due to the risk of loss from counterparties not performing under the terms of a derivative contract. Adverse moves within the financial or commodities markets could negatively impact our counterparties' ability to fulfill obligations to us. To minimize such risk, we only enter into derivative contracts with counterparties that we determine are creditworthy, which includes performing both quantitative and qualitative assessments of these counterparties, based on their credit ratings and credit default swap rates where applicable. Additionally, our derivative contracts are with multiple counterparties, reducing our exposure to any individual counterparty.

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, for the periods indicated:

	Year Ended December 31,		
	2020	**2019**	**2018**
Company A	13%	10%	16%
Company B	—	16%	23%

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

Certain of our debt instruments bear interest at floating rates based on LIBOR, and the LIBOR component of our interest on these instruments exposes us to interest rate risk. Borrowings under the Credit Facility bear interest at a floating tiered rate based on facility usage plus the 1-month LIBOR, resulting in a weighted average interest rate of 2.65% as of December 31, 2020. However, we have entered into interest rate swaps through the end of 2021 to mitigate a significant portion of our exposure to volatility in the 1-month LIBOR. Additionally, our 2025 Second Lien Term Loans bear interest at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor, resulting in a weighted average interest rate of 10.00% as of December 31, 2020. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of our interest rate derivatives.

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 in 2020, 2019 or 2018. 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.

pwc

Report of Independent Auditors

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

We have audited the accompanying consolidated financial statements of Ascent Resources Utica Holdings, LLC and its subsidiaries, which comprise the consolidated balance sheets as of December 31, 2020 and 2019, 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, 2020.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the consolidated financial statements based on our audits. We conducted our audits 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 from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Ascent Resources Utica Holdings, LLC and its subsidiaries as of December 31, 2020 and 2019, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2020 in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 10, 2021

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED BALANCE SHEETS

($ in thousands)	December 31, 2020		December 31, 2019	
Current Assets:				
Cash and cash equivalents	$	8,843	$	7,346
Accounts receivable – natural gas, oil and NGL sales		223,976		260,759
Accounts receivable – joint interest and other		8,466		20,425
Short-term derivative assets		8,202		248,118
Other current assets		8,316		8,468
Total Current Assets		257,803		545,116
Property and Equipment:				
Natural gas and oil properties, based on successful efforts accounting		8,791,061		8,233,964
Other property and equipment		31,565		30,818
Less: accumulated depreciation, depletion and amortization		(2,627,213)		(1,890,506)
Property and Equipment, net		6,195,413		6,374,276
Other Assets:				
Long-term derivative assets		2,401		70,778
Other long-term assets		16,232		20,248
Total Assets	$	6,471,849	$	7,010,418
Current Liabilities:				
Accounts payable	$	36,736	$	68,364
Revenue payable		84,142		99,300
Accrued interest		31,287		36,787
Current portion of long-term debt, net		12,498		—
Short-term derivative liabilities		54,144		—
Other current liabilities		257,495		280,841
Total Current Liabilities		476,302		485,292
Long-Term Liabilities:				
Long-term debt, net of current portion		2,707,382		2,838,676
Long-term derivative liabilities		113,160		—
Other long-term liabilities		73,010		5,067
Total Long-Term Liabilities		2,893,552		2,843,743
Commitments and contingencies (Note 9)				
Member's Equity		3,101,995		3,681,383
Total Liabilities and Member's Equity	$	6,471,849	$	7,010,418

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF OPERATIONS

($ in thousands)	Year Ended December 31, 2020	2019	2018
Revenues:			
Natural gas	$ 1,258,594	$ 1,589,099	$ 1,444,368
Oil	138,723	241,521	133,786
NGL	118,224	148,639	109,221
Commodity derivative (loss) gain	(19,167)	441,139	(90,881)
Total Revenues	1,496,374	2,420,398	1,596,494
Operating Expenses:			
Lease operating expenses	78,430	72,606	50,163
Gathering, processing and transportation expenses	919,986	856,126	658,117
Production and ad valorem taxes	37,495	34,167	23,362
Exploration expenses	104,230	124,477	156,450
General and administrative expenses	63,825	61,027	63,794
Acquisition expenses	—	—	9,407
Natural gas and oil depreciation, depletion and amortization	733,450	702,414	500,773
Depreciation and amortization of other assets	3,568	3,239	3,912
Total Operating Expenses	1,940,984	1,854,056	1,465,978
(Loss) Income from Operations	(444,610)	566,342	130,516
Other (Expense) Income:			
Interest expense, net	(134,213)	(109,114)	(92,227)
Change in fair value of contingent payment right	(6,518)	—	—
Change in fair value of embedded derivative	—	5,026	18,865
Losses on purchases or exchanges of debt	(6,037)	—	(62,233)
Other income	1,867	3,711	683
Total Other Expense	(144,901)	(100,377)	(134,912)
Net (Loss) Income	$ (589,511)	$ 465,965	$ (4,396)

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

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

($ in thousands)	Year Ended December 31, 2020	2019	2018
Balance, Beginning of Period	$ 3,681,383	$ 3,215,097	$ 2,182,500
Contributions from Member	10,123	321	1,036,993
Net (loss) income	(589,511)	465,965	(4,396)
Balance, End of Period	$ 3,101,995	$ 3,681,383	$ 3,215,097

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS

($ in thousands)	Year Ended December 31, 2020	2019	2018
Cash Flows from Operating Activities:			
Net (loss) income	$ (589,511)	$ 465,965	$ (4,396)
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation, depletion and amortization	737,018	705,653	504,685
Change in fair value of commodity derivatives	475,027	(249,457)	34,138
Change in fair value of interest rate derivatives	569	—	—
Impairment of unproved natural gas and oil properties	100,207	115,802	153,047
Non-cash interest expense	25,347	27,305	28,301
Stock-based compensation	1,775	—	—
Change in fair value of contingent payment right	6,518	—	—
Change in fair value of embedded derivative	—	(5,026)	(18,865)
(Gains) losses on purchases or exchanges of debt	(11,500)	—	62,233
Other	(1,577)	148	(1,218)
Changes in operating assets and liabilities			
Decrease (increase) in accounts receivable and other assets	46,407	159,274	(274,558)
(Decrease) increase in accounts payable, liabilities and other	(17,259)	(79,546)	205,366
Net Cash Provided by Operating Activities	773,021	1,140,118	688,733
Cash Flows from Investing Activities:			
Drilling and completion costs	(571,860)	(1,125,216)	(906,064)
Acquisitions of natural gas and oil properties	(139,106)	(258,001)	(1,409,494)
Proceeds from divestitures of natural gas and oil properties	—	12,474	6,564
Additions to other property and equipment	(1,509)	(3,547)	(1,512)
Net Cash Used in Investing Activities	(712,475)	(1,374,290)	(2,310,506)
Cash Flows from Financing Activities:			
Proceeds from credit facility borrowings	1,065,000	1,270,000	1,525,000
Repayment of credit facility borrowings	(1,300,000)	(1,030,000)	(577,000)
Proceeds from issuance of long-term debt, net	300,000	—	587,166
Repayment of long-term debt	(138,764)	—	(525,000)
Proceeds from the Exchange (Note 4)	20,000	—	—
Cash paid for debt issuance costs	(6,842)	(9,512)	(11,725)
Cash paid for debt prepayment costs	—	—	(52,500)
Contributions from Member	—	—	567,647
Other	1,557	—	—
Net Cash (Used in) Provided by Financing Activities	(59,049)	230,488	1,513,588
Net Increase (Decrease) in Cash and Cash Equivalents	1,497	(3,684)	(108,185)
Cash and Cash Equivalents, Beginning of Period	7,346	11,030	119,215
Cash and Cash Equivalents, End of Period	$ 8,843	$ 7,346	$ 11,030
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest and interest paid in kind	$ 115,589	$ 88,392	$ 63,583
Supplemental disclosures of significant non-cash investing activities:			
(Decrease) increase in accrued capital expenditures	$ (57,925)	$ (96,471)	$ 56,740
Contributions from Member	$ —	$ —	$ 469,346

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 (the "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 ("GAAP"), and intercompany accounts and balances have been eliminated.

Risks and Uncertainties

On January 30, 2020, the World Health Organization (the "WHO") announced a global health emergency due to the spread of a novel coronavirus ("COVID-19"), which was classified as a pandemic in March 2020 based on the rapid increase in global exposure. Under the guidance of the WHO and the Centers for Disease Control and Prevention (the "CDC") and in an effort to slow the spread of the virus, many local, state and national governments implemented new laws and regulations which led to a steep decline in the global demand for oil and, to a lesser extent, natural gas. Due to the commodity price environment in 2020, we curtailed certain wells in an effort to optimize revenue in future periods. All such wells have since been turned back to sales; however, further curtailments could be utilized in the future.

As the full impact of COVID-19 and the volatility in commodity prices continues to evolve, and, although we are monitoring both closely, we cannot be certain as to the full magnitude that they will have on our future financial condition, liquidity and results of operations.

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 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 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, which are the basis of the calculation of the depletion and impairment of natural gas and oil properties.

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. Accounts receivable at December 31, 2020 and 2019 were $232.4 million and $281.2 million, respectively, and consisted primarily of accrued natural gas, oil and NGL revenue receivables and receivables from joint interest billings to owners of properties we operate. 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. All accounts receivable are considered to be fully collectible; therefore, no allowance for doubtful accounts is recorded in the consolidated balance sheets as of December 31, 2020 or 2019.

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 of undeveloped leases and the costs incurred to acquire, drill and complete productive wells and development wells 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, 2020, 2019 or 2018. 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, 2020, 2019 or 2018. 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, our anticipated drilling program, remaining lease terms and potential shifts in business strategy employed by management. For the years ended December 31, 2020, 2019 and 2018, we recorded impairments of $100.2 million, $115.8 million and $153.0 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

Natural Gas and Oil DD&A. 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 three to seven years. Our 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 $3.6 million, $3.2 million and $3.9 million for the years ended December 31, 2020, 2019 and 2018, 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 $5.9 million and $1.7 million as of December 31, 2020 and 2019, respectively.

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 and are amortized through their respective maturity dates 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 and are amortized 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 revenue from the sale of natural gas, oil and NGL based on our share of volumes sold. See Note 2 for further discussion of our revenues from contracts with customers.

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:

	Year Ended December 31,		
	2020	2019	2018
Company A	13%	10%	16%
Company B	—	16%	23%

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 enter into derivative instruments to reduce our exposure to fluctuations in future commodity prices and floating interest rates in order to protect our expected operating cash flow against significant market movements or volatility. All 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 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 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 5 for further discussion of our derivative instruments.

Stock-Based Compensation. We recognize compensation cost for equity-classified awards based on the fair value on the date of the grant, and such amount is recognized on a straight-line basis over the requisite service period. Compensation cost for liability-classified awards are recognized once it becomes probable that such awards will be settled, and the cost is measured at fair value as of the date it becomes probable and is re-measured at fair value at the end of each reporting period. Stock-based compensation is presented as general and administrative expenses on the consolidated statements of operations. See Note 7 for further discussion of our stock-based compensation.

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

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 2019 and 2018 consolidated financial statements to conform to the presentation used for the 2020 consolidated financial statements.

Adopted and Recently Issued Accounting Pronouncements

In August 2020, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2020-06, *Debt - Debt with Conversion and Other Options, Subtopic 470-20, and Derivatives and Hedging - Contracts in Entity's Own Equity, Subtopic 815-40.* This ASU modifies the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity, and adds new disclosure requirements. The amendments are effective for annual reporting periods, and interim periods within those periods, beginning after December 15, 2021 for public entities. For non-public entities, the amendments are effective for annual reporting periods beginning after December 15, 2023, including interim periods within those fiscal years. Entities may elect to apply the amendments in this guidance using either the modified retrospective method or the full retrospective method. We are currently evaluating the impact this standard will have on our financial statements and related disclosures.

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 were 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. We adopted ASU 2018-13 effective January 1, 2020 and did not experience a material impact to our financial statements or disclosures.

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 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 were 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* ("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 ASU 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 were effective for interim and annual reporting periods beginning after December 15, 2018 for public business entities. In accordance with the amendments made in ASU 2020-05, for non-public entities, Topic 842 will be effective for annual reporting periods beginning after December 15, 2021 and for interim periods beginning after December 15, 2022, 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 March 10, 2021, the date the consolidated financial statements were issued, we completed our evaluation of material subsequent events for disclosure, and such items are discussed herein. See Note 4, *Convertible Notes*, for a discussion of our recent debt maturities.

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 specific index price adjusted for 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, 2020 and December 31, 2019, receivables from contracts with customers were $224.0 million and $260.8 million, respectively, and were reported in accounts receivable – natural gas, oil and NGL sales on the consolidated balance sheets.

3. Property and Equipment

Net property and equipment included the following:

	December 31,	
($ in thousands)	2020	2019
Proved natural gas and oil properties	$ 7,752,763	$ 7,155,998
Unproved natural gas and oil properties	1,038,298	1,077,966
Other property and equipment	31,565	30,818
Total Property and Equipment	8,822,626	8,264,782
Accumulated depreciation, depletion and amortization	(2,627,213)	(1,890,506)
Property and Equipment, net	$ 6,195,413	$ 6,374,276

At December 31, 2020 and 2019, we did not have any capitalized well costs associated with exploratory wells that were pending determination of proved reserves.

4. Debt

Our debt consisted of the following as of the dates indicated:

($ in thousands)	December 31, 2020	December 31, 2019
Long-Term Debt:		
Credit Facility[a]	$ 953,000	$ 1,188,000
Second lien term loans due November 2025[b]	549,822	—
10.00% senior notes due April 2022	67,992	975,000
7.00% senior notes due November 2026	600,000	600,000
9.00% senior notes due November 2027	348,294	—
8.25% senior notes due December 2028	300,000	—
Convertible notes due March 2021[c]	—	77,336
Net debt issuance costs	(8,248)	(3,522)
Net debt discounts and premiums	(103,478)	1,862
Total Long-Term Debt, net of current portion	2,707,382	2,838,676
Plus current maturities of long-term debt, net[c]	12,498	—
Total Debt, net	$ 2,719,880	$ 2,838,676

(a) The interest rate was 2.65% and 4.01% as of December 31, 2020 and 2019, respectively.

(b) The interest rate was 10.00% as of December 31, 2020.

(c) The interest rate was 6.50% as of December 31, 2020 and 2019. The Convertible Notes (defined below) were reclassified from a long-term liability to a current liability due to their maturity date of March 1, 2021. The carrying value of the Convertible Notes as of December 31, 2020 consisted of $8.3 million of outstanding principal plus a premium that is being accreted over the life of the notes. The Convertible Notes matured on March 1, 2021, and were redeemed for $13.1 million, including the premium.

Credit Facility

Our $2.5 billion senior secured revolving credit facility ("Credit Facility") matures on April 1, 2024, and as of December 31, 2020, it had a fully committed borrowing base of $1.85 billion, of which $250.0 million was authorized for letters of credit. 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 May 1 and November 1 of each year primarily 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 as determined by lenders under the Credit Facility at their discretion. Additionally, we may request an interim redetermination of the borrowing base in certain circumstances, including acquisitions of proved reserves in excess of certain thresholds. In November 2020, the borrowing base under the Credit Facility was reaffirmed at $1.85 billion. As of December 31, 2020, we had $953.0 million of borrowings outstanding and $148.7 million of letters of credit issued under the Credit Facility.

Under the Credit Facility agreement, we may borrow either base rate loans or Eurodollar loans, and as of December 31, 2020, all of the borrowings under the Credit Facility were Eurodollar loans. Principal amounts borrowed are payable on the maturity date and may be repaid prior to the maturity date without any premium or penalty. 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 2.00% to 3.00% per annum based on Credit Facility utilization. Due to the weighted average 1-month LIBOR being 0.15% for the applicable interest periods on the most recent election dates, we were subject to a weighted average rate of 2.65% per annum as of December 31, 2020. We have entered into interest rate swaps through the end of 2021 to mitigate a significant portion of our exposure to future volatility in LIBOR. See Note 5 for further information regarding our interest rate derivatives.

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 2.00% to 3.00% 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.

As of December 31, 2020, we had $16.1 million in unamortized debt issuance costs associated with the Credit Facility, which are presented as other long-term assets on the consolidated balance sheet.

Second Lien Term Loans

In October 2020, we issued $537.8 million in aggregate principal amount of second lien term loans ("2025 Second Lien Term Loans") and $339.7 million in aggregate principal amount of 9.00% senior unsecured notes due 2027 ("2027 Notes") in exchange for $856.7 million of aggregate principal amount of 2022 Notes (the "Exchange"). In connection with the Exchange, we issued an additional $12.0 million in aggregate principal amount of 2025 Second Lien Term Loans, $8.6 million in aggregate principal amount of 2027 Notes and equity of our Parent to certain existing equity holders and their designated affiliates in exchange for an aggregate contribution of $20.0 million in cash. The proceeds were used to pay fees for the Exchange and to repay a portion of the borrowings outstanding under the Credit Facility. See Note 8 for further discussion of our debt held by certain related parties. The 2025 Second Lien Term Loans are due on November 1, 2025, and interest is payable at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor, on January 13, April 13, July 13 and October 13 of each year, beginning with January 13, 2021. The 2025 Second Lien Term Loans are secured by second liens on substantially all of our assets, including our natural gas and oil properties. Our obligations under the 2025 Second Lien Term Loans are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. We may redeem some or all of the 2025 Second Lien Term Loans at any time at redemption prices ranging from 105.00% to 100.00% on or after April 13, 2023. At any time prior to April 13, 2023, we may redeem some or all of the 2025 Second Lien Term Loans at a price of 100.00% plus a make-whole premium (as defined in the agreement), and we may redeem up to 40% of the aggregate principal amount of 2025 Second Lien Term Loans at a price of 105.00% with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2025 Second Lien Term Loans at a price of 101.00%, plus accrued and unpaid interest.

Senior Notes

2022 Notes. In April 2017, we issued $1.5 billion in aggregate principal amount of 10.00% senior unsecured notes due 2022 ("2022 Notes") in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act of 1933 (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. Our obligations under the 2022 Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. In 2018, we redeemed $525.0 million of the aggregate principal amount of the 2022 Notes (the "Redemption") at a redemption price equal to 110.00% of the principal thereof, plus accrued and unpaid interest, and recorded a $62.2 million loss. During the year ended December 31, 2020, we repurchased approximately $50.3 million of outstanding principal amount of the 2022 Notes at a discount for $35.4 million in cash, plus accrued and unpaid interest, and recorded a $14.3 million gain, including the write-off of unamortized debt issuance costs and discounts. Additionally, in October 2020, we completed the Exchange which resulted in $856.7 million of aggregate principal amount of 2022 Notes being exchanged for a combination of 2025 Second Lien Term Loans and 2027 Notes. As of December 31, 2020, we had $68.0 million in principal of 2022 Notes outstanding. We may redeem some or all of the 2022 Notes at any time at redemption prices ranging from 107.50% to 100.00%.

In connection with the issuance and sale of the 2022 Notes, we entered into a registration rights agreement with the initial purchasers pursuant to which, if an initial public offering of our equity occurs, we have agreed to file a registration statement with the United States Securities and Exchange Commission (the "SEC") within 365 days, so that the holders may exchange the 2022 Notes for registered notes that have substantially identical terms. 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 up to a maximum aggregate increase of 1.00% per annum until we regain compliance with the agreement.

2026 Notes. In October 2018, we issued $600.0 million in aggregate principal amount of 7.00% senior unsecured notes due 2026 ("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. We used the proceeds primarily to redeem $525.0 million of outstanding principal of the 2022 Notes and pay accrued and unpaid interest up to, but excluding, the date of the Redemption. The remaining net proceeds were used to repay borrowings under the Credit Facility. Our obligations under the 2026 Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. We may redeem some or all of the 2026 Notes at any time at redemption prices ranging from 103.50% to 100.00% on or after November 1, 2021. At any time prior to November 1, 2021, we may redeem some or all of the 2026 Notes at a price of 100.00% plus a make-whole premium (as defined in the indenture), and we may redeem up to 40% of the aggregate principal amount of 2026 Notes at a price of 107.00% with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2026 Notes at a price of 101.00%, plus accrued and unpaid interest.

2027 Notes. In October 2020, we issued $339.7 million in aggregate principal amount of 2027 Notes as part of the Exchange. The 2027 Notes are due on November 1, 2027, and interest is payable at an annual rate of 9.00% on May 1 and November 1 of each year, beginning with May 1, 2021. Our obligations under the 2027 Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. We accounted for the Exchange as a modification to existing debt, and no gain or loss was recognized related to the principal exchanged. We incurred $17.7 million of fees related to the Exchange during the year ended December 31, 2020, which are presented as a loss on purchases or exchanges of debt on the consolidated statements of operations. Additionally, $8.6 million of 2027 Notes were issued to certain existing equity holders of our Parent, and their designated affiliates, the proceeds of which were used primarily to pay fees related to the Exchange. See Note 8 for further discussion of our debt held by certain related parties.

Unless and until a Triggering Event (as defined below) has occurred and we have paid all consideration payable in respect thereof, we may redeem some or all of the 2027 Notes (i) at any time prior to November 1, 2026, subject to a make-whole premium (as defined in the indenture) and (ii) on or after November 1, 2026, at a redemption price equal to 100% of the principal amount of 2027 Notes to be redeemed, in each case plus accrued and unpaid interest to, but excluding, the redemption date. If a Triggering Event has occurred and we have paid all consideration payable in respect thereof, we may redeem some or all of the 2027 Notes (i) at any time prior to November 1, 2023, subject to a make-whole premium and (ii) on or after November 1, 2023, at redemption prices ranging from 104.50% to 100.00%, in each case plus accrued and unpaid interest to, but excluding, the redemption date. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2027 Notes at a price of 101.00%, plus accrued and unpaid interest.

The 2027 Notes also contain a contingent payment right, which entitles the holders to receive a fixed amount of cash or equity, ranging from 30% to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if certain triggering events (the "Triggering Events") occur. The Triggering Events include a qualified public offering, a qualified merger or consolidation that results in our equity holders receiving an equity interest that is listed or quoted on any national securities exchange, or a change of control. The amount paid is dependent upon the timing of the first occurrence of such Triggering Events. The contingent payment right is required to be bifurcated and accounted for at fair value, and as of December 31, 2020, the estimated fair value was $65.3 million and is presented as other long-term liabilities on the consolidated balance sheet. See Note 6 for further discussion of the contingent payment right valuation. In certain instances, the contingent payment right may be replaced by a Contingent Value Right ("CVR"), which entitles the holder of the CVR to the same fixed amount of consideration upon the same Triggering Events despite no longer holding the associated 2027 Notes. However, if the 2027 Notes are voluntarily sold to us prior to a Triggering Event through means of open market transactions or other negotiated transactions, the contingent payment right will expire.

2028 Notes. In December 2020, we issued $300.0 million in aggregate principal amount of 8.25% senior unsecured notes due 2028 ("2028 Notes") in a private placement to eligible purchasers under Rule 144A and Regulation S of the Securities Act. The 2028 Notes are due on December 31, 2028, and interest is payable at an annual rate of 8.25% on February 1 and August 1 of each year, beginning with August 1, 2021. The net proceeds were used to repay a portion of the borrowings outstanding under the Credit Facility. Our obligations under the 2028 Notes are fully and unconditionally guaranteed, jointly and severally, by our current material subsidiaries and will be so guaranteed by any of our future material subsidiaries. We may redeem some or all of the 2028 Notes at any time at redemption prices ranging from 104.125% to 100.00% on or after February 1, 2024. At any time prior to February 1, 2024, we may redeem some or all of the 2028 Notes at a price of 100.00% plus a make-whole premium (as defined in the indenture), and we may redeem up to 40% of the aggregate principal amount of 2028 Notes at a price of 108.25% with an amount of cash not greater than the net cash proceeds of one or more equity offerings, subject to certain conditions. Upon the occurrence of a qualifying change of control, we are required to offer to repurchase all or any part of the 2028 Notes at a price of 101.00%, plus accrued and unpaid interest.

The 2022 Notes, 2026 Notes, 2027 Notes and 2028 Notes (together, 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 are effectively subordinated to all of our existing and future secured debt to the extent of the value of the collateral securing such indebtedness.

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. In 2020, we repurchased an additional $69.0 million of outstanding principal amount of the Convertible Notes for $103.4 million in cash, plus accrued and unpaid interest, and recorded a $2.7 million loss, including the write-off of debt issuance costs, discounts and premiums. The remaining $8.3 million in principal of Convertible Notes matured on March 1, 2021 and were redeemed at 153.8% of the outstanding principal value, plus accrued and unpaid interest up to, but not including, the maturity date, as provided in the indenture, for $13.1 million in cash.

Debt Covenants

The agreements governing our debt contain 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: (i) a consolidated leverage ratio, which requires us to maintain a consolidated funded indebtedness to consolidated EBITDAX ratio for the aggregate of the last four consecutive quarters (as defined in the Credit Facility agreement) of not more than 4.00 to 1.00 for each fiscal quarter and (ii) a modified current ratio (as defined in the Credit Facility agreement), 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. We were in compliance with all applicable debt covenants as of December 31, 2020.

Debt Maturities

The principal amount of debt maturities for the five years ended after December 31, 2020 and thereafter are as follows:

($ in thousands)	Principal Amount of Debt Securities
2021[a]	$ 12,781
2022	67,992
2023	—
2024	953,000
2025	549,822
2026 and Thereafter	1,248,294
Total	$ 2,831,889

(a) The Convertible Notes due in 2021 included a premium of $4.5 million that was payable upon maturity. The premium was accreted over the scheduled maturity period of the debt. The Convertible Notes matured on March 1, 2021.

5. Derivative Instruments

We use derivative instruments to mitigate our exposure to fluctuations in future commodity prices and floating interest rates in order to protect our anticipated operating cash flow against significant market movements or volatility. We do not use derivative instruments for speculative or trading purposes. As of December 31, 2020, our derivative instruments consisted of the following types of instruments:

- *Swaps*. We receive a fixed price and pay a floating 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 the 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*. Our natural gas production is sold at various delivery points that at times may have material spreads or volatility relative to NYMEX. Therefore, we periodically use basis swaps to fix the differential between product prices at the following market locations relative to NYMEX: Chicago (Citygate), Dawn (Ontario), MichCon, Rex Zone 3, 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.

- *Interest Rate Swaps*. Interest rate swaps are used to fix interest rates on existing or anticipated floating rate indebtedness. The purpose of these instruments is to manage our existing or anticipated exposure to unfavorable interest rate changes. We pay a fixed interest rate and receive a floating interest rate from the counterparty subject to a floor of zero basis points.

All 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 derivative instruments are recorded in earnings as we have not elected hedge accounting for any of our derivative instruments. By using 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, 2020, 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:						$ (73,975)
2021	1,123,000	$ 2.54				
2022	1,018,000	$ 2.52				
2023	550,000	$ 2.45				
2024	165,000	$ 2.46				
Collars:						2,789
2021	180,000		$ 3.05	$ 2.50		
Three-way collars:						(975)
2022	160,000		$ 3.00	$ 2.50	$ 2.01	
Call options:						(106,929)
2021	335,000		$ 3.02			
2022	360,000		$ 2.99			
2023	370,000		$ 2.89			
2024	400,000		$ 2.84			
Basis swaps:						22,769
2021	534,000	$ (0.27)				
2022	348,000	$ (0.18)				
Total Estimated Fair Value						$ (156,321)

The following table sets forth the average volumes per day associated with our outstanding oil derivative instruments as of December 31, 2020, the contracted weighted average oil prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Swap Strike Price	Sold Call Strike Price	Fair Value ($ in thousands)
Oil:				
Swaps:				$ 1,629
2021	2,200	$ 50.44		
Call options:				(448)
2021	3,300		$ 70.00	
Total Estimated Fair Value				$ 1,181

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of December 31, 2020, the contracted weighted average NGL prices and the estimated fair values:

	Average Volume (bbl/d)	Weighted Average Prices ($/bbl) Swap Strike Price	Fair Value ($ in thousands)
NGL:			
Swaps - Propane:			$ (992)
2021	2,000	$ 24.78	
Total Estimated Fair Value			$ (992)

The following table sets forth the notional amounts associated with our outstanding interest rate derivative instruments as of December 31, 2020, the contracted fixed rate to be paid, the contracted floating rate to be received and the estimated fair value:

($ in thousands)	Notional Amount	Fixed Rate	Floating Rate[(a)]	Fair Value
Interest Rate Swaps:				$ (569)
2021	$ 550,000	0.2525 %	1-month LIBOR	
Total Estimated Fair Value				$ (569)

(a) The interest rate swaps include an embedded put option (floor) of zero basis points, limiting our exposure should 1-month LIBOR rates fall below this threshold.

The following tables summarize the fair value of our 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, 2020 and 2019:

($ in thousands)	December 31, 2020		
Consolidated Balance Sheet Classification	Fair Value, Gross	Amounts Netted on Balance Sheet	Fair Value, Net
Short-term derivative assets:			
Commodity derivatives	$ 44,802	$ (36,600)	$ 8,202
Total short-term derivative assets	$ 44,802	$ (36,600)	$ 8,202
Long-term derivative assets:			
Commodity derivatives	$ 64,755	$ (62,354)	$ 2,401
Total long-term derivative assets	$ 64,755	$ (62,354)	$ 2,401
Short-term derivative liabilities:			
Commodity derivatives	$ 90,175	$ (36,600)	$ 53,575
Interest rate derivatives	569	—	569
Total short-term derivative liabilities	$ 90,744	$ (36,600)	$ 54,144
Long-term derivative liabilities:			
Commodity derivatives	$ 175,514	$ (62,354)	$ 113,160
Total long-term derivative liabilities	$ 175,514	$ (62,354)	$ 113,160

($ in thousands)	December 31, 2019		
Consolidated Balance Sheet Classification	Fair Value, Gross	Amounts Netted on Balance Sheet	Fair Value, Net
Short-term derivative assets:			
Commodity derivatives	$ 298,113	$ (49,995)	$ 248,118
Total short-term derivative assets	$ 298,113	$ (49,995)	$ 248,118
Long-term derivative assets:			
Commodity derivatives	$ 148,721	$ (77,943)	$ 70,778
Total long-term derivative assets	$ 148,721	$ (77,943)	$ 70,778
Short-term derivative liabilities:			
Commodity derivatives	$ 49,995	$ (49,995)	$ —
Total short-term derivative liabilities	$ 49,995	$ (49,995)	$ —
Long-term derivative liabilities:			
Commodity derivatives	$ 77,943	$ (77,943)	$ —
Total long-term derivative liabilities	$ 77,943	$ (77,943)	$ —

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

($ in thousands)	Consolidated Statements of Operations Presentation	Year Ended December 31, 2020	2019	2018
Commodity derivatives	Commodity derivative (loss) gain	$ (19,167)	$ 441,139	$ (90,881)
Interest rate derivatives	Interest expense, net	$ (790)	$ —	$ —

6. 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 on a Recurring Basis

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, 2020 and 2019. The fair values of the commodity derivatives and interest rate derivatives are based primarily on inputs that are derived from observable data at commonly quoted intervals and are therefore classified as Level 2. The fair value of the contingent payment right is based on unobservable inputs and is therefore classified as Level 3. See Note 5 for further information regarding our derivative instruments.

	Fair value measurements at December 31, 2020 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Commodity derivatives	$ —	$ 10,603	$ —	$ 10,603
Total	$ —	$ 10,603	$ —	$ 10,603
Derivative liabilities:				
Commodity derivatives	$ —	$ 166,735	$ —	$ 166,735
Interest rate derivatives	—	569	—	569
Contingent payment right[a]	—	—	65,302	65,302
Total	$ —	$ 167,304	$ 65,302	$ 232,606

[a] The contingent payment right is presented as other long-term liabilities on the consolidated balance sheet.

	Fair value measurements at December 31, 2019 using:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Derivative assets:				
Commodity derivatives	$ —	$ 318,896	$ —	$ 318,896
Total	$ —	$ 318,896	$ —	$ 318,896
Derivative liabilities:				
Commodity derivatives	$ —	$ —	$ —	$ —
Total	$ —	$ —	$ —	$ —

Contingent Payment Right. The 2027 Notes contain a contingent payment right that is required to be bifurcated and accounted for as a liability at fair value. Upon initial issuance of the 2027 Notes, the estimated fair value of the contingent payment right was $58.8 million, and as of December 31, 2020 the estimated fair value was $65.3 million. The contingent payment right is presented as other long-term liabilities on the consolidated balance sheet and as a Level 3 measurement. The most significant unobservable inputs used to estimate the fair value of the contingent payment right are the probability of a triggering event prior to maturity and the discount rate, which as of December 31, 2020 were 70.0% and 12.4%, respectively. Changes in its fair value are presented as a change in fair value of the contingent payment right on the consolidated statement of operations. There were no transfers in or out of our Level 3 fair value measurements.

Fair Value of Debt

The carrying amounts and estimated fair values of our debt instruments as of December 31, 2020 and 2019 are shown in the table below. The fair values were estimated using Level 2 market data inputs. See Note 4 for further information regarding our debt.

	December 31,			
	2020		2019	
($ in thousands)	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$ 953,000	$ 953,000	$ 1,188,000	$ 1,188,000
2025 Second Lien Term Loans	527,108	606,179	—	—
2022 Notes	67,486	70,477	962,594	969,764
2026 Notes	587,925	576,655	586,330	478,500
2027 Notes	277,006	387,863	—	—
2028 Notes	294,857	299,683	—	—
Convertible Notes	12,498	12,665	101,752	105,950
Total	$ 2,719,880	$ 2,906,522	$ 2,838,676	$ 2,742,214

7. Stock-Based Compensation

In July 2020, our Parent established a long-term incentive plan (the “Plan”) in order to further our growth and success. Under this Plan, the board of managers of our Parent may, among other things, grant time-vested restricted stock units (“Time-Vested RSUs”) and performance-vested restricted stock units (“Performance-Vested RSUs,” and together with the Time-Vested RSUs, the “RSUs”) to certain of our employees and managers of the board of our Parent. Under the Plan, 360.2 million Series B units (“Units”) of the Parent were reserved for issuance. As of December 31, 2020, the Parent had granted approximately 159.8 million Time-Vested RSUs and 159.8 million Performance-Vested RSUs which are currently outstanding.

The Time-Vested RSUs are accounted for as equity awards. Stock-based compensation related to the Time-Vested RSUs is measured based on the fair value on the date of grant using appropriate valuation techniques and is recognized on a straight-line basis over the requisite service period. Performance-Vested RSUs are accounted for as liability awards, whose ultimate settlement may be partially or fully offset by certain cash awards received prior to vesting. Such cash awards allow Plan participants to receive cash payments associated with us achieving certain financial metrics during a calendar year and, therefore, such payments are accrued when they become probable and determinable. Stock-based compensation related to the Performance-Vested RSUs is recognized once it becomes probable that the performance condition will be achieved. We account for forfeitures during the period in which they occur by reversing the expense previously recognized for such awards. Stock-based compensation cost for the year ended December 31, 2020 was $1.8 million.

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 $67.0 million, $104.8 million and $79.9 million during the years ended December 31, 2020, 2019 and 2018, respectively. As of December 31, 2020 and 2019, we had accounts receivable – natural gas, oil and NGL sales of $9.5 million and $21.2 million, respectively, due from these purchasers. We also incurred gathering, processing and transportation expenses associated with these agreements of $623.7 million, $607.8 million and $463.9 million during the years ended December 31, 2020, 2019 and 2018, respectively. As of December 31, 2020 and 2019, we had $96.6 million and $96.1 million of payables, 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*.

Long-Term Debt

In connection with the Exchange, we issued $12.0 million in aggregate principal amount of 2025 Second Lien Term Loans and $8.6 million in aggregate principal amount of 2027 Notes to certain existing equity holders and their designated affiliates. As of December 31, 2020, $8.6 million in aggregate principal amount of 2025 Second Lien Term Loans and $0.3 million in aggregate principal amount of 2027 Notes were held by certain related parties.

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. We may also periodically be involved in disputes with our midstream counterparties, some of which are related parties as discussed in Note 8, including disputes arising due to the overlapping nature of dedication provisions, ownership and contractual interests in the Utica Shale. A liability is recognized for any contingency that is probable 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.

For all such claims, disputes and threatened or pending litigation, as of December 31, 2020, we have accrued $15.0 million, which is presented as other current liabilities on the consolidated balance sheet. The final resolution of such matters could differ materially from management's estimates.

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, 2020:

($ in thousands)	Pipeline Commitments	Operating Leases	Other Purchase Obligations	Total
2021	$ 659,358	$ 10,730	$ 2,358	$ 672,446
2022	661,360	4,764	2,202	668,326
2023	662,143	2,205	110	664,458
2024	654,034	51	—	654,085
2025	642,187	—	—	642,187
2026 and Thereafter	5,476,955	—	—	5,476,955
Total	$ 8,756,037	$ 17,750	$ 4,670	$ 8,778,457

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 likelihood 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, $148.7 million in letters of credit and $311.7 million in surety bonds were issued by us or on our behalf to certain transportation providers as of December 31, 2020. Our credit support includes support provided to certain related parties, which, as of December 31, 2020, included $121.3 million in letters of credit and $184.0 million in surety bonds. For information regarding certain other transactions with related parties, see Note 8.

Operating Leases

We lease certain equipment and office space as part of our operations. Lease expense related to operating leases totaled $6.5 million, $4.6 million and $3.5 million during the years ended December 31, 2020, 2019 and 2018, respectively. 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 the dates indicated:

($ in thousands)	December 31, 2020	December 31, 2019
Gathering, processing and transportation expense accrual	$ 130,058	$ 131,524
Drilling and completion cost accrual	48,922	69,762
Production and ad valorem taxes accrual	28,593	26,494
Other	49,922	53,061
Total Other Current Liabilities	$ 257,495	$ 280,841

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:

	December 31,	
($ in thousands)	2020	2019
Proved	$ 7,752,763	$ 7,155,998
Unproved	1,038,298	1,077,966
Total	8,791,061	8,233,964
Accumulated depreciation, depletion and amortization	(2,610,024)	(1,876,770)
Net Capitalized Costs	$ 6,181,037	$ 6,357,194

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

	Year Ended December 31,		
($ in thousands)	2020	2019	2018
Acquisition costs of properties:			
Proved properties	$ 4,811	$ 18,075	$ 675,242
Unproved properties	121,211	218,337	1,146,056
Total property acquisition costs	126,022	236,412	1,821,298
Exploration costs	3,926	8,098	3,404
Development costs	531,283	1,058,883	953,393
Total	$ 661,231	$ 1,303,393	$ 2,778,095

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 results do not include the effects of commodity derivatives or 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.

	Year Ended December 31,		
($ in thousands)	2020	2019	2018
Revenues, excluding the effects of commodity derivatives	$ 1,515,541	$ 1,979,259	$ 1,687,375
Lease operating expenses	(78,430)	(72,606)	(50,163)
Gathering, processing and transportation expenses	(919,986)	(856,126)	(658,117)
Production and ad valorem taxes	(37,495)	(34,167)	(23,362)
Exploration expenses	(104,230)	(124,477)	(156,450)
Natural gas and oil depreciation, depletion and amortization	(733,450)	(702,414)	(500,773)
Results of Operations	$ (358,050)	$ 189,469	$ 298,510

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. Our net quantities of proved reserves include our royalty interests and exclude any interests owned by others.

Our proved natural gas, oil and NGL reserves for the years ended December 31, 2020, 2019 and 2018 were prepared by our independent reservoir engineers utilizing analogy to offset production, volumetrics, conventional decline curve analysis and rate transient analysis. Proved reserves estimates for the year ended December 31, 2020 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"). NSAI's type curves were used as the basis for their reserves projections. Proved reserves estimates for the years ended December 31, 2019 and 2018 were prepared by Software Integrated Solutions (formerly known as PetroTechnical Services), a Division of Schlumberger Technology Corporation.

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 SEC.

Subsequent to December 31, 2020, 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, 2020. 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, 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
Extensions, discoveries and other additions	822,859	4,644	9,445	907,393
Revisions	(248,908)	(5,999)	(25,796)	(439,680)
Production	(646,982)	(4,291)	(9,304)	(728,553)
Proved Reserves at December 31, 2020	8,073,034	42,613	110,361	8,990,875
Proved developed reserves:				
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
December 31, 2020	3,830,924	16,273	57,831	4,275,548
Proved undeveloped reserves:				
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
December 31, 2020	4,242,110	26,340	52,530	4,715,327

(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, 2020, we added approximately 907.4 bcfe in proved reserves through the continued development of our Utica Shale acreage. Downward revisions of previous estimates of approximately 439.7 bcfe included revisions of 258.6 bcfe resulting from removing PUDs where it was determined development would occur outside of our five-year development plan and other revisions to proved reserves estimates of 181.1 bcfe primarily due to type curve revisions. As of December 31, 2020, all proved undeveloped locations were in accordance with the SEC five year rule. The unadjusted 12-month average prices used to calculate reserves at December 31, 2020 were $1.99 per mmbtu for natural gas and $39.54 per barrel for oil and condensate.

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. We added proved reserves through acquisitions of 12.4 bcfe. As of December 31, 2019, all proved undeveloped locations were in accordance with the SEC five year rule. The unadjusted 12-month average prices used to calculate reserves at December 31, 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. We added proved reserves through acquisitions of 1.073 tcfe. As of December 31, 2018, all proved undeveloped locations were in accordance with the SEC five year rule. The unadjusted 12-month average prices used to calculate reserves at December 31, 2018 were $3.10 per mmbtu for natural gas and $65.56 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, 2020, 2019 and 2018 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)	**2020**	**2019**	**2018**
Future cash inflows	$ 18,007,344	$ 25,534,390	$ 26,284,676
Future production costs	(13,243,886)	(14,026,060)	(11,763,838)
Future development costs	(1,975,980)	(2,887,918)	(2,207,600)
Future net cash flows	2,787,478	8,620,412	12,313,238
Discount to present value at 10% annual rate	(1,522,378)	(4,662,760)	(6,362,658)
Standardized Measure of Discounted Future Net Cash Flows	$ 1,265,100	$ 3,957,652	$ 5,950,580

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:

($ in thousands)	Year Ended December 31, 2020	2019	2018
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Period	$ 3,957,652	$ 5,950,580	$ 2,296,579
Sales of natural gas, oil and NGL produced, net of production costs	(479,630)	(1,016,360)	(955,733)
Net changes in prices and production costs	(3,519,899)	(2,589,311)	938,280
Extensions and discoveries, net of production and development costs	87,268	1,240,076	2,002,124
Changes in future development costs	455,834	(74,440)	(129,486)
Previously estimated development costs incurred during the year	545,553	387,391	375,879
Revisions of previous quantity estimates	(133,195)	(473,097)	196,707
Purchase of reserves	—	19,718	816,944
Sales of reserves	—	(2,262)	—
Accretion of discount	395,765	595,058	229,658
Changes in production rates and other	(44,248)	(79,701)	179,628
Standardized Measure of Discounted Future Net Cash Flows, End of Period	$ 1,265,100	$ 3,957,652	$ 5,950,580