ASCENT RESOURCES UTICA HOLDINGS, LLC

Consolidated Financial Statements

As of December 31, 2023 and 2022 and for the Years Ended December 31, 2023, 2022 and 2021

ASCENT RESOURCES UTICA HOLDINGS, LLC
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GLOSSARY OF COMMONLY USED TERMS

The following are abbreviations and definitions of certain terms used in this document:

"2025 Second Lien Term Loans" means our second lien term loans due November 2025.

"2026 Notes" means our 7.00% senior unsecured notes due November 2026.

"2027 Notes" means our 9.00% senior unsecured notes due November 2027.

"2028 Notes" means our 8.25% senior unsecured notes due December 2028.

"2029 Notes" means our 5.875% senior unsecured notes due June 2029.

"bbl(s)" means barrel(s) as used in reference to crude oil, condensate or NGL. One barrel equals 42 U.S. gallons liquid volume.

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

"bcf" means billion cubic feet of natural gas.

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

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

"Credit Facility" means our senior secured revolving credit facility entered into on April 5, 2017, and related agreements, due June 30, 2027, which will accelerate to August 2, 2026 if an amount greater than or equal to $150.0 million of the 2026 Notes is outstanding as of that date.

"DD&A" means depreciation, depletion and amortization.

"exploratory well" means 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.

"GAAP" means U.S. generally accepted accounting principles.

"gross" means:

- In relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalty and overriding royalty interests;
- In relation to our wells, the total number of wells in which we own 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 own an interest.

"LIBOR" means London Interbank Offered Rate.

"mbbls" means thousand barrels of crude oil, condensate or NGL.

"mbbls/d" means thousand barrels of crude oil, condensate or NGL per day.

"mcf" means thousand cubic feet of natural gas.

"mcfe" means 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" means million British thermal units.

"mmbtu/d" means million British thermal units per day.

"mmcf" means million cubic feet of natural gas.

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

"mmcfe" means 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" means 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) after the deduction of royalty and overriding royalty interests;
- In relation to our wells, the total number of wells obtained by aggregating our working interest after the deduction of royalty and overriding royalty interests in each of our gross wells;
- In relation to our interest in a property, the total area in acres in which we own 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 acres after the deduction of royalty and overriding royalty interests.

"NGL" means natural gas liquids.

"NYMEX" means the New York Mercantile Exchange.

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

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

"proved reserves" means, as defined by the Securities and Exchange Commission ("SEC"), 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 and under existing economic conditions, operating methods and government regulations.

"proved undeveloped" or *"PUD(s)"* means 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" means 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" means 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 natural gas or related substances to market, and all permits and financing required to implement the project.

"royalty interest" means an interest in a natural gas and oil 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.

"Senior Notes" means our 2026 Notes, 2027 Notes, 2028 Notes and 2029 Notes.

"SOFR" means Secured Overnight Financing Rate.

"standardized measure" means 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 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 rates 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" means trillion cubic feet equivalent, with one barrel of oil, condensate or NGL converted to six thousand cubic feet of natural gas.

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

"working interest" means 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" means West Texas Intermediate.

Business Overview

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

We are one of the largest private producers of natural gas in the United States and are focused on acquiring, developing and operating natural gas and oil properties located 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 365,000 net leasehold acres, including approximately 75,900 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 4,400 mineral acres that are being developed by third-party operators and provide enhanced value without additional capital costs or operating expenses.

We are focused on generating stakeholder value through the responsible development of our assets, while upholding our position as a prominent producer of affordable, reliable, cleaner-burning energy in the United States. We achieve this by continuously enhancing our drilling and completion techniques, minimizing our operating costs and maximizing recovery from our assets, with the goal of generating strong corporate-level returns and sustainable free cash flow in a capital efficient, financially disciplined, and environmentally conscious manner.

2023 Highlights

Prepayment of Second Lien Term Loans

In May 2023, we prepaid the outstanding aggregate principal amount of our 2025 Second Lien Term Loans at a price of 105.00% for $577.3 million, plus accrued and unpaid interest (the "2025 Prepayment") utilizing borrowings from our Credit Facility. Subsequently, we issued an additional $212.6 million in aggregate principal amount of our existing 2028 Notes (the "2028 Add-On Notes") to certain former holders of our 2025 Second Lien Term Loans and used the $210.0 million of proceeds to partially repay borrowings under our Credit Facility. These transactions reduce our associated interest expense, simplify our capital structure and extend our debt maturity profile, all of which help reinforce our balance sheet, enhance our future cash flows and improve our long-term financial profile. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of our debt transactions.

Operational Update

During the year ended December 31, 2023, we spud 74 new wells, successfully fractured 75 wells, turned 71 wells in line and incurred $1.02 billion of total capital expenditures, including $36.2 million of capitalized interest. This development activity is in line with our strategy of maintaining current levels of production, which allows us to remain focused on preserving financial flexibility.

Equity Distribution Program

In 2023, we funded $25.0 million of distributions that were declared and paid by our Parent to its unitholders. Additionally, in conjunction with the initial distribution, our Parent effected a reverse stock split of its outstanding units at a ratio of 1-for-100 (1:100).

Market Conditions, Trends and Uncertainties

Commodity Prices

Prices for natural gas, oil and NGL that we produce significantly impact our revenue and cash flows. In the current economic environment, we expect that commodity prices for some or all the commodities we produce will remain volatile due to rising macroeconomic uncertainties and geopolitical tensions, including Russia's invasion of Ukraine as well as hostilities in the Middle East. These factors and the resulting volatility are outside of our control and could adversely impact our business, financial condition, results of operations and future cash flows. We actively monitor commodity markets and use derivative instruments to reduce our exposure to fluctuations in future commodity prices and protect our anticipated operating cash flows against significant market movements or volatility. See Note 6 of the notes to our consolidated financial statements included in this report for further information regarding our derivative instruments.

Inflation

To address the heightened inflation rates triggered by supply and demand imbalances beginning in 2021, governmental monetary policies involving increased interest rates were initiated to moderate economic activity. While these measures appear to have reduced inflation, they have simultaneously raised the borrowing costs associated with our Credit Facility and could increase borrowing costs on potential new debt.

Despite the annual rate of inflation in the United States decreasing throughout 2023, it remains elevated relative to historical averages. Continued labor shortages and ongoing uncertainties in global supply chains, which have been affected by Russia's invasion of Ukraine and hostilities in the Middle East, continue to apply pressure on global economics. Heightened inflationary pressures, specifically on the services and raw materials that we use throughout our operations, have impacted our business and may continue to impact us moving forward. Additionally, certain of our long-term midstream contracts that have Consumer Price Index or Producer Price Index adjustments have also been impacted and may continue to be impacted in the future.

These economic variables are outside of our control and may adversely impact our business, financial condition, results of operations and future cash flows. However, we continue to monitor them and remain focused in our efforts to increase the efficiencies of our operations, which may, in part, offset certain costs that have risen due to inflation.

Properties

Well Data

As of December 31, 2023, we held an interest in 1,289 gross (813 net) productive wells, including 1,069 gross (813 net) properties in which we held a working interest and 220 gross properties in which we only held an overriding or royalty interest. Of the wells in which we had a working interest, 1,004 gross (774 net) were classified as productive natural gas wells and 65 gross (39 net) were classified as productive oil wells. We operated approximately 882 gross (795 net) of our productive wells in which we had a working interest. During 2023, we drilled 71 gross (63 net) wells as operator and participated in 23 gross (2 net) wells drilled by other operators. We also held an overriding or royalty interest in another two gross wells drilled by other operators. We operated approximately 99% of our net production volumes in 2023.

Drilling Activity

The following table describes the new productive wells we operated or participated in during the periods indicated:

	Productive Wells Drilled during the Year Ended December 31,					
	2023		2022		2021	
	Gross	Net	Gross	Net	Gross	Net
Development	94	65	85	76	74	69

As of December 31, 2023, we had 28 gross (23 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, 2023, 2022 or 2021.

Acreage

The following tables set forth information as of December 31, 2023 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, 2023:

Developed Acres		Undeveloped Acres		Total Acres	
Gross	Net	Gross	Net[(a)]	Gross	Net[(b)]
232,053	218,939	176,341	146,031	408,394	364,970

(a) Approximately 70% 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 80,300 mineral acres, including approximately 4,400 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, 2023 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
2024	9,508	8,965
2025	2,333	2,242
2026	6,390	6,362
2027	7,581	7,518
2028 and thereafter	18,851	18,764
Total	44,663	43,851

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 from third parties to satisfy shortfalls should they occur. The following table sets forth our natural gas firm sales commitments as of December 31, 2023:

	Natural Gas (mmbtu)
2024	63,272,620
2025	46,745,550
2026	46,745,550
2027	46,745,550
2028	46,873,620
2029	11,526,300
Total	261,909,190

We have certain ethane firm sales commitments that extend through 2042 which require a minimum volume, and allow for additional discretionary volume if elected by the purchaser, to be delivered. Both the minimum and additional discretionary volumes are redetermined annually, and are not anticipated to have a material impact on our financial statements.

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,		
	2023	2022	2021
Net Production Volumes:			
Natural gas (mmcf)	712,691	719,470	645,752
Oil (mbbls)	3,739	2,814	3,110
NGL (mbbls)	7,384	5,794	7,012
Natural Gas Equivalent (mmcfe)	779,429	771,119	706,484
Average Sales Prices:			
Natural gas ($/mcf)	$ 2.48	$ 6.53	$ 3.89
Oil ($/bbl)	$ 68.92	$ 87.73	$ 60.47
NGL ($/bbl)	$ 26.82	$ 41.26	$ 34.47
Natural Gas Equivalent ($/mcfe)	$ 2.86	$ 6.73	$ 4.16
Settlements of commodity derivatives ($/mcfe)[a]	0.29	(2.98)	(1.17)
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.15	$ 3.75	$ 2.99
Expenses ($/mcfe):			
Lease operating expenses	$ 0.16	$ 0.13	$ 0.12
Gathering, processing and transportation expenses	$ 1.25	$ 1.27	$ 1.34

(a) The year ended December 31, 2022 excludes a one-time payment of $300.0 million in April 2022 to restructure a portion of our May through December 2022 natural gas swaps, resulting in an increase to our weighted average strike prices for these periods.

Natural Gas, Oil and NGL Reserves

All of our estimated proved reserves are located within the Point Pleasant interval of the Utica Shale. The following table sets forth our proved reserves as of December 31, 2023:

	December 31, 2023			
	Natural Gas (mmcf)	Oil (mbbls)	NGL (mbbls)	Total (mmcfe)
Proved developed reserves[a]	5,471,996	19,079	75,155	6,037,398
Proved undeveloped reserves	2,203,640	26,686	80,869	2,848,971
Total	7,675,636	45,765	156,024	8,886,369

(a) Approximately 143.8 bcfe, or 2%, of our proved developed reserves were proved developed non-producing.

The table below sets forth information as of December 31, 2023, 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, 2023. 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, 2023. The average adjusted prices used in our reserve reports were $2.23 per mcf of natural gas, $70.40 per bbl of oil and $24.05 per bbl of NGL utilizing a benchmark of $2.64 per mmbtu of natural gas and $78.21

per bbl of oil and condensate. 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, 2023. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service costs, 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, 2023.

	December 31, 2023		
($ in thousands)	Proved Developed	Proved Undeveloped	Total Proved
Estimated future net revenue	$ 4,906,954	$ 2,552,164	$ 7,459,118
PV-10	$ 2,654,980	$ 838,416	$ 3,493,396
Standardized measure[(a)]			$ 3,493,396

(a) See Note 13, *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, 2023, our estimated proved reserves included approximately 2.849 tcfe of reserves classified as proved undeveloped, compared to approximately 3.291 tcfe as of December 31, 2022. The table below is a summary of changes in our PUDs for 2023:

	Total (mmcfe)
Proved undeveloped reserves as of December 31, 2022	3,290,804
Extensions, discoveries and other additions	706,615
Revisions	(131,772)
Conversions into proved developed reserves	(1,016,676)
Proved undeveloped reserves as of December 31, 2023	2,848,971

Our proved undeveloped extensions and discoveries of approximately 706.6 bcfe of reserves resulted from the continued development of our Utica Shale acreage. Revisions of previous PUD estimates included downward revisions of 131.8 bcfe, including 28.7 bcfe due to change in price. The remaining downward revisions were primarily due to the removal of PUDs where it was determined development would occur beyond five-years from PUD booking, net of additions of previously proved locations that were added to our current five-year development plan, and development plan optimization. As of December 31, 2023, there were no PUDs that had remained undeveloped for five years or more, in accordance with the SEC five-year rule. A majority of the PUDs removed from the proved undeveloped category as of December 31, 2023 are expected to be developed in our current five-year development plan as we continue to optimize through active leasing and extending laterals. In 2023, we invested $535.6 million to convert 1.017 tcfe from proved undeveloped reserves to proved developed reserves.

The future net revenues attributable to our estimated PUDs of $2.55 billion as of December 31, 2023, and associated PV-10 of $838.4 million, have been calculated assuming that we will expend approximately $1.61 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 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

The estimation of our proved reserves is prepared internally by our staff of petroleum engineers and geoscience professionals. Our Senior Vice President of Exploration and Resource Development is the technical person primarily responsible for overseeing the preparation of all of our reserve estimates. He holds a Bachelor of Science degree in Chemical Engineering from the University of Oklahoma. Before joining Ascent, he held various technical and managerial positions with Chesapeake Energy Corporation, Atlantic Richfield Company, Phillips Petroleum and ConocoPhillips and has more than 25 years of reservoir estimation and operations experience.

The preparation of our historical proved reserve estimates is 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 our Senior Vice President of Exploration and Resource Development 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.

We engaged the services of Netherland, Sewell & Associates, Inc. (“NSAI”), an independent petroleum engineering firm, to audit the 2023 reserves estimated by our petroleum engineering staff. The purpose of this audit was to provide additional assurance on the reasonableness of internally prepared reserve estimates and represented 100% of our proved reserves and 100% of the present value of our proved reserves discounted at 10%. The technical persons at NSAI primarily responsible for auditing the estimates presented herein meet 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 (“SPE Standards”). Additionally, our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished during the reserve audit process. 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 for our properties, such as ownership interest, natural gas, oil and NGL production, well test data, commodity prices and operating and development costs. Any differences found in the analysis of the estimation of our proved reserves by our independent reserve engineers are reviewed with our Senior Vice President of Exploration and Resource Development. Our estimates of proved reserves and the present value of such reserves, discounted at 10%, did not differ from the estimates of our independent reserve engineers by more than the recommended threshold of 10% set forth in the SPE Standards.

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 reflect our future plans, estimates, beliefs and expected performance, all of which involve known and unknown risks, uncertainties and assumptions. These risks and uncertainties include, but are not limited to, volatility in commodity markets, uncertainties in estimating proved reserves and forecasting production results, the costs and results of our development program, the condition of capital markets and our ability to access them, rising inflation and interest rates and governmental policies aimed at transitioning towards lower carbon energy, and other factors that are outside of our control. While we cannot be certain as to the full magnitude these and other factors may have on our future financial condition, liquidity, results of operations or cash flows, we actively monitor them as they may cause actual results to differ from our historical results or current expectations. Considering these risks, uncertainties and assumptions, the forward-looking events discussed herein may not occur. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

The following discussion and analyses primarily focus on 2023 and 2022. Discussions of 2021 items and year-to-year comparisons between 2022 and 2021 are not included in this report but can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in our prior year financial statements, which are available on our website.

Results of Operations

Year Ended December 31, 2023 Compared to 2022

The following tables set forth certain information for the periods indicated regarding our revenues, average sales prices received and net production volumes:

	Year Ended December 31,		Variance	
	2023	2022	Amount	Percent
Revenues ($ in thousands):				
Natural gas	$ 1,770,416	$ 4,700,531	$ (2,930,115)	(62)%
Oil	257,708	246,866	10,842	4 %
NGL	198,018	239,071	(41,053)	(17)%
Total Revenues, before effects of commodity derivatives	$ 2,226,142	$ 5,186,468	$ (2,960,326)	(57)%
Average Sales Prices:				
Natural gas ($/mcf)	$ 2.48	$ 6.53	$ (4.05)	(62)%
Oil ($/bbl)	$ 68.92	$ 87.73	$ (18.81)	(21)%
NGL ($/bbl)	$ 26.82	$ 41.26	$ (14.44)	(35)%
Natural Gas Equivalent ($/mcfe)	$ 2.86	$ 6.73	$ (3.87)	(58)%
Settlements of commodity derivatives ($/mcfe)[(a)]	0.29	(2.98)	3.27	110 %
Average sales price, after effects of settled derivatives ($/mcfe)	$ 3.15	$ 3.75	$ (0.60)	(16)%

(a) The year ended December 31, 2022 excludes a one-time payment of $300.0 million in April 2022 to restructure a portion of our May through December 2022 natural gas swaps, resulting in an increase to our weighted average strike prices for these periods.

	Year Ended December 31,		Variance	
	2023	2022	Amount	Percent
Net Production Volumes:				
Natural gas (mmcf)	712,691	719,470	(6,779)	(1)%
Oil (mbbls)	3,739	2,814	925	33 %
NGL (mbbls)	7,384	5,794	1,590	27 %
Natural Gas Equivalent (mmcfe)	779,429	771,119	8,310	1 %
Average Daily Net Production Volumes:				
Natural gas (mmcf/d)	1,953	1,971	(18)	(1)%
Oil (mbbls/d)	10	8	2	25 %
NGL (mbbls/d)	20	16	4	25 %
Natural Gas Equivalent (mmcfe/d)	2,135	2,113	22	1 %

Revenues. Natural gas, oil and NGL revenues (excluding the effects of derivatives) decreased $2.96 billion during the year ended December 31, 2023 compared to the same period in 2022, of which $3.05 billion was attributable to a 58% decrease in our average sales prices that was partially offset by $90.1 million attributable to a 1% increase in our net production volumes.

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, 2023 remained constant:

($ in thousands)	Volumes	Price Fluctuation per Unit	Effect on Sales and Cash Flows
Commodity:			
Natural Gas (mmcf)	712,691	$ 0.10	$ 71,269
Oil (mbbls)	3,739	$ 1.00	$ 3,739
NGL (mbbls)	7,384	$ 1.00	$ 7,384

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 cash flows against significant market movements or volatility. For the years ended December 31, 2023 and 2022, we recorded gains related to our commodity derivatives of $2.10 billion and losses of $2.69 billion, respectively, including settlement gains on our derivative instruments of $222.5 million and settlement losses of $2.30 billion for the same periods. The following table sets forth the settlements of our derivative instruments by commodity for the periods indicated:

	Year Ended December 31,	
($ in thousands)	2023	2022
Net Settlements of Commodity Derivatives:		
Natural Gas	$ 223,529	$ (2,209,997)
Oil	(11,638)	(67,033)
NGL	10,658	(22,909)
Total Net Settlements of Commodity Derivatives	$ 222,549	$ (2,299,939)

In addition, we paid $300.0 million in April 2022 to restructure a portion of our May through December 2022 natural gas swaps, resulting in an increase to our weighted average strike prices for these periods.

Changes in the fair value of commodity derivatives vary based on future commodity prices and have no impact on our cash flows until derivative contracts are either settled or monetized prior to settlement. As commodity prices increase or decrease, such changes will have an opposite effect on the fair value and ultimate settlement of our derivatives. See Quantitative and Qualitative Disclosures About Market Risk, *Commodity Demand and Price Risk,* and Note 6 of the notes to our consolidated financial statements included in this report for further information regarding our derivative instruments.

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

	Year Ended December 31,		Variance	
	2023	2022	Amount	Percent
Operating Expenses ($ in thousands):				
Lease operating expenses	$ 123,212	$ 101,659	$ 21,553	21 %
Gathering, processing and transportation expenses	$ 975,245	$ 979,987	$ (4,742)	— %
Taxes other than income	$ 47,372	$ 45,724	$ 1,648	4 %
Exploration expenses	$ 12,625	$ 49,142	$ (36,517)	(74)%
General and administrative expenses	$ 90,930	$ 77,112	$ 13,818	18 %
Depreciation, depletion and amortization	$ 723,951	$ 676,053	$ 47,898	7 %
Operating Expenses ($/mcfe):				
Lease operating expenses	$ 0.16	$ 0.13	$ 0.03	23 %
Gathering, processing and transportation expenses	$ 1.25	$ 1.27	$ (0.02)	(2)%
Taxes other than income	$ 0.06	$ 0.06	$ —	— %
Exploration expenses	$ 0.02	$ 0.06	$ (0.04)	(67)%
General and administrative expenses	$ 0.12	$ 0.10	$ 0.02	20 %
Depreciation, depletion and amortization	$ 0.93	$ 0.88	$ 0.05	6 %

Lease Operating Expenses. Lease operating expenses increased $21.6 million for the year ended December 31, 2023 compared to 2022 due to an increased number of producing wells provided by our drilling program and inflationary pressure on salt water disposal costs, labor and materials.

Gathering, Processing and Transportation Expenses. Gathering, processing and transportation expenses decreased $4.7 million for the year ended December 31, 2023 compared to 2022 primarily due to the following:

- Gathering expenses increased $19.9 million or $0.02 per mcfe, primarily due to increased fees on certain gathering systems as well as increases in compression costs.
- Processing expenses increased $16.0 million or $0.02 per mcfe, primarily due to increased wet gas production during the year ended December 31, 2023.
- Transportation expenses decreased $40.6 million or $0.06 per mcfe, primarily due to a refund received in 2023 for a favorable rate adjustment associated with one of our firm transportation contracts.

Taxes Other Than Income. Taxes other than income primarily consists of production taxes and ad valorem taxes. The increase for the year ended December 31, 2023 compared to 2022 was primarily due to increased ad valorem tax rates.

Exploration Expenses. Exploration expenses were primarily driven by impairments of $9.6 million and $46.9 million for the years ended December 31, 2023 and 2022, 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 in future periods.

General and Administrative Expenses. General and administrative expenses increased $13.8 million for the year ended December 31, 2023 compared to 2022 due to the following:

- The year ended December 31, 2022 included $17.9 million of long-term incentive compensation related to the 2022 Cash Awards. See Note 8 of the notes to our consolidated financial statements included in this report for additional information regarding the Cash Awards.
- The year ended December 31, 2022 included a benefit related to a legal settlement of $8.8 million.
- The year ended December 31, 2023 included increases in litigation and estimated legal settlements of $25.1 million. See Note 11 of the notes to our consolidated financial statements included in this report for additional information regarding litigation matters.
- The remaining decrease in general and administrative expenses of $2.2 million was due to a decrease in other general corporate matters.

Depreciation, Depletion and Amortization. DD&A increased $47.9 million primarily due to a $0.05 increase in our per mcfe rate during the year ended December 31, 2023 compared to 2022. The increase in our per mcfe rate was primarily the result of increased drilling and completion costs due to inflationary pressure on labor and materials and increased development of our liquids-rich and volatile oil positions in 2023.

Interest Expense. Interest expense was $205.9 million and $209.7 million for the years ended December 31, 2023 and 2022, respectively, detailed as follows along with our weighted average debt outstanding:

	Year Ended December 31,		Variance	
($ in thousands)	**2023**	**2022**	**Amount**	**Percent**
Credit Facility	$ 61,738	$ 49,561	$ 12,177	25 %
2025 Second Lien Term Loans[(a)]	25,744	61,506	(35,762)	(58)%
Senior Notes	132,750	121,688	11,062	9 %
Gain on interest rate derivatives	(2,872)	(5,489)	2,617	(48)%
Amortization of debt discounts, premium and issuance costs	20,848	21,710	(862)	(4)%
Other	3,853	4,648	(795)	(17)%
Interest Expense, before capitalized interest	242,061	253,624	(11,563)	(5)%
Capitalized interest	(36,151)	(43,893)	7,742	(18)%
Total Interest Expense, net	$ 205,910	$ 209,731	$ (3,821)	(2)%
Weighted Average Debt Outstanding:				
Credit Facility	$ 711,466	$ 955,932	$ (244,466)	(26)%
2025 Second Lien Term Loans[(a)]	183,776	549,822	(366,046)	(67)%
Senior Notes	1,783,362	1,648,187	135,175	8 %
Weighted Average Debt Outstanding	$ 2,678,604	$ 3,153,941	$ (475,337)	(15)%

(a) We prepaid the outstanding principal amount in May 2023. See Note 5 of the notes to our consolidated financial statements included in this report for information regarding the 2025 Prepayment.

The decrease in interest expense before capitalized interest for the year ended December 31, 2023 compared to 2022 was primarily due to the 2025 Prepayment and an overall reduction in our weighted average debt outstanding. This was partially offset by increased interest expense on our Senior Notes as a result of the issuance of the 2028 Add-On Notes and increased variable interest rates on funds drawn on our Credit Facility. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of our floating interest rates on debt.

Losses on Purchases or Exchanges of Debt. In May 2023, we recognized a loss of $26.9 million related to the 2025 Prepayment. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of the 2025 Prepayment.

Liquidity and Capital Resources

Overview

Our primary sources of funds are internally generated cash flows from operations, borrowings under our Credit Facility and historically have included proceeds from the issuance of debt and equity contributions from our Parent. Our future success in maintaining our proved reserves and current levels of production will be highly dependent upon net cash provided by our operating activities and the capital resources available to us, and there can be no assurance that such resources will be available to us on favorable terms, or at all. 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 to repay or redeem portions of our indebtedness and fund equity distribution payments made by our Parent to its unitholders. Additionally, we may use availability under our Credit Facility, securities offerings or other debt issuances 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 or privately negotiated transactions. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of our debt.

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. We establish a capital budget at the beginning of each calendar year and periodically review and may adjust our allocation for capital expenditures as business conditions warrant. Actual capital expenditures may vary due to many factors, including drilling results, commodity prices, industry conditions, the prices and availability of goods and services, inflationary pressure and the extent to which properties are acquired or assets are sold.

As of December 31, 2023, we had a cash balance of $6.7 million and availability under our Credit Facility of $1.07 billion. In November 2023, we reaffirmed the current borrowing base under our Credit Facility of $3.0 billion and the elected commitments of $2.0 billion. We currently plan to fund our capital program through cash on hand, expected cash flows from our operations and borrowings under our Credit Facility. Based on current expectations, we anticipate being able to satisfy all of our financial obligations and liquidity needs for the next twelve months.

Long-term cash flows are subject to a number of variables including our level of production and prices as well as various economic conditions that have historically affected the natural gas and oil industry. Based on the significant borrowing capacity under our Credit Facility with a maturity date in 2027, commodity derivatives we have in place which cover a portion of our expected annual production through 2026 and having no significant maturities of senior notes until 2026 and beyond, we believe we will have adequate capital resources and liquidity for the foreseeable future.

Sources of Cash and Cash Equivalents

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

	Year Ended December 31,	
($ in thousands)	2023	2022
Cash provided by operating activities	$ 1,147,059	$ 2,042,012
Proceeds from Credit Facility borrowings, net of repayments[(a)]	395,000	—
Proceeds from issuance of long-term debt	210,000	—
Financing commodity derivative settlements	(53,530)	(378,270)
Payment to restructure commodity derivatives	—	(300,000)
Total Sources of Cash and Cash Equivalents	$ 1,698,529	$ 1,363,742

(a) Net borrowings under our Credit Facility were primarily related to the prepayment of our 2025 Second Lien Term Loans, partially offset by proceeds received from the issuance of our 2028 Add-On Notes. See discussion below for further details of these transactions.

Our primary source of funds is net cash flow provided by operating activities, which is highly dependent upon our natural gas, oil and NGL production, the sales prices that we receive and our commodity hedging activities. Commodity prices are subject to wide fluctuations and are driven by market supply and demand, which is impacted by many factors. To mitigate these fluctuations, we enter into various derivative contracts, which ensures a certain level of cash flow to fund our operations. Any payments made to our derivative counterparties are ultimately funded by proceeds received from the sale of our production. However, production receipts can lag hedging settlements, creating timing differences between the associated cash flows. Although we are continually securing additional derivative positions for portions of our expected future production, there can be no assurance that we will be able to add additional derivative positions at favorable prices. See Quantitative and Qualitative Disclosures About Market Risk and Note 6 of the notes to our consolidated financial statements included in this report for further details.

Cash provided by operating activities. We generated $1.15 billion and $2.04 billion in cash flows from our operations for the years ended December 31, 2023 and 2022, respectively. Including the impacts of our financing commodity derivative settlements, which consist of certain commodity derivative contracts that contain an other than insignificant financing element, whereby the associated settlement payments are classified as financing activities rather than cash flows from our operations, we generated $1.09 billion and $1.66 billion for the years ended December 31, 2023 and 2022, respectively. The decrease 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.

Proceeds from issuance of long-term debt. In May 2023, we issued an additional $212.6 million in aggregate principal amount of 2028 Add-On Notes to certain former holders of our 2025 Second Lien Term Loans and used the $210.0 million of proceeds to partially repay borrowings under our Credit Facility. See Note 5 of the notes to our consolidated financial statements included in this report for further details of the 2028 Add-On Notes.

Payment to restructure commodity derivatives. In April 2022, we paid $300.0 million to restructure a portion of our May through December 2022 natural gas swaps, resulting in an increase to our weighted average strike prices for those periods.

Uses of Cash and Cash Equivalents

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

	Year Ended December 31,	
($ in thousands)	**2023**	**2022**
Natural Gas and Oil Capital Expenditures:		
Drilling and completion costs	$ 893,338	$ 820,614
Land and leasehold costs	126,859	97,828
Interest capitalized[(a)]	36,151	43,893
Total Natural Gas and Oil Capital Expenditures	1,056,348	962,335
Other Uses of Cash and Cash Equivalents:		
Repayment of Credit Facility, net of borrowings	—	125,000
Repayment of long-term debt	549,822	2,970
Cash paid for debt issuance and amendment costs	11,219	16,855
Cash paid for debt prepayment costs	27,491	—
Cash paid to Member for equity distributions	25,003	—
Cash paid to Member for long-term incentive Cash Awards	17,856	—
Cash paid for acquisition	—	250,882
Additions to other property and equipment	2,769	2,096
Other	5,197	5,384
Total Other	639,357	403,187
Total Uses of Cash and Cash Equivalents	$ 1,695,705	$ 1,365,522

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

Drilling and completion costs. Our cash drilling and completion costs were $893.3 million and $820.6 million in 2023 and 2022, respectively. The increase in drilling and completion costs in 2023 was primarily the result of increased lateral lengths drilled per well and inflationary pressure on labor and materials.

Land and leasehold costs. We spent cash of $126.9 million and $97.8 million in 2023 and 2022, respectively, primarily related to the acquisition of leases arising in the ordinary course of business.

Repayment of long-term debt and debt prepayment costs. We spent cash of $549.8 million during the year ended December 31, 2023 to prepay the outstanding aggregate principal amount of our 2025 Second Lien Term Loans and incurred a 5.0% cash premium of $27.5 million, utilizing borrowings from our Credit Facility. See Note 5 of the notes to our consolidated financial statements included in this report for further details of the 2025 Prepayment.

Cash paid to Member for equity distributions. In 2023, we funded $25.0 million of distributions that were declared and paid by our Parent to its unitholders, of which $0.3 million was recognized as long-term incentive compensation expense.

Cash paid to Member for long-term incentive Cash Awards. We paid $17.9 million of cash to our Member during the year ended December 31, 2023. The cash was used by our Parent to fund the 2022 calendar year cash payments made under its long-term incentive plan. See Note 8 of the notes to our consolidated financial statements included in this report for further discussion of our Parent's long-term incentive plan.

Cash paid for acquisition. In 2022, we acquired assets in Ohio for a total purchase price of $270.0 million, or $250.9 million after closing purchase price adjustments. The transaction was financed with a combination of cash on hand and borrowings under the Credit Facility. See Note 3 of the notes to our consolidated financial statements included in this report for further discussion of the acquisition.

Certain Indebtedness

Credit Facility. Our Credit Facility matures on June 30, 2027, and as of December 31, 2023, it had an elected commitment of $2.0 billion, of which $250.0 million was authorized for letters of credit. The maturity date will accelerate to August 2, 2026 if an amount greater than or equal to $150.0 million of our 2026 Notes is outstanding as of that date. The amount available to be borrowed under our Credit Facility is subject to a borrowing base that is required to be redetermined semiannually on or about April 1 and October 1 of each year, primarily based on the estimated value and future net cash flows of our proved reserves and the value of our commodity derivative positions, as determined by lenders under our 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. In November 2023, we reaffirmed the current borrowing base of $3.0 billion and the elected commitments of $2.0 billion under our Credit Facility. As of December 31, 2023, we had $765.0 million of borrowings outstanding and $169.1 million of letters of credit issued under our Credit Facility. See Note 5, *Credit Facility*, of the notes to our consolidated financial statements included in this report for further discussion of the terms of our Credit Facility.

Senior Notes. The following table summarizes certain material terms of our outstanding Senior Notes as of December 31, 2023:

($ in thousands)	2026 Notes	2027 Notes[(a)]	2028 Notes[(b)]	2029 Notes
Outstanding principal	$597,000	$348,294	$512,637	$400,000
Interest rate	7.00%	9.00%	8.25%	5.875%
Maturity date	November 1, 2026	November 1, 2027	December 31, 2028	June 30, 2029
Interest payment dates	May 1, Nov. 1	May 1, Nov. 1	Feb. 1, Aug. 1	Mar. 1, Sept. 1
Make-whole redemption date	Expired[(c)]	November 1, 2026	Expired[(d)]	September 1, 2024

(a) The 2027 Notes also contain a contingent payment right. See Note 5, *Senior Notes*, and Note 7, *Contingent Payment Right*, of the notes to our consolidated financial statements included in this report for further discussion.

(b) The outstanding principal amount includes the 2028 Add-On Issuance. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion.

(c) The 2026 Notes are currently callable at 101.167% until November 1, 2024.

(d) The 2028 Notes are currently callable at 104.125% until February 1, 2025.

Upon the occurrence of a change of control (as defined in the respective indenture), we are required to offer to repurchase all or any part of our outstanding Senior Notes at a price of 101.00%, plus accrued and unpaid interest. We are also required to offer to repurchase the outstanding Senior Notes at a price of 100.00%, plus accrued and unpaid interest, in the event of certain asset sales if we do not otherwise apply the net proceeds of such asset sales as permitted under the applicable indenture. The Senior Notes may be redeemed, at our option, prior to their maturity. Prior to the make-whole redemption date specified in the table above, each applicable series of Senior Notes may be redeemed at a make-whole premium based on the present value of the remaining principal and interest payments to the make-whole redemption date. After the applicable make-whole redemption date, the Senior Notes may be redeemed at a declining premium set forth in the applicable indenture. See Note 5, *Senior Notes*, of the notes to our consolidated financial statements included in this report for further discussion of the terms and early redemption dates and prices for the outstanding Senior Notes.

Debt Covenants. The agreements governing our debt contain certain restrictive and financial covenants. See Note 5 of the notes to our consolidated financial statements included in this report for further discussion of the terms of our debt covenants. 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. As of December 31, 2023, we were in compliance with all applicable debt covenants.

Contractual Obligations and Off-Balance Sheet Arrangements

As of December 31, 2023, our material contractual obligations included repayments of our outstanding borrowings and associated interest payment obligations, derivative obligations, asset retirement obligations, lease obligations, letters of credit, surety bonds and various other commitments we enter into in the ordinary course of business that could result in future cash obligations. In addition, we have entered into certain pipeline capacity commitments with various counterparties, some of which extend beyond 20 years, 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. The estimated gross undiscounted future commitments under these pipeline agreements were approximately $7.13 billion as of December 31, 2023; however, third parties that own a working interest in the wells we operate, and royalty and overriding royalty interest owners, where applicable, will be responsible for their proportionate share of these costs. As discussed above, we believe our existing sources of liquidity will be sufficient to fund our near and long-term contractual obligations. See Notes 5, 6, 10 and 11 of the notes to our consolidated financial statements included in this report for further discussion. We do not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities.

Critical Accounting 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. However, because future events and their effects cannot be determined with certainty, actual results could differ materially from our assumptions and estimates.

On a regular basis, management reviews our accounting policies, assumptions, estimates and judgments to ensure that our consolidated financial statements are presented fairly and in accordance with GAAP. Our significant accounting policies are discussed in Note 1, *Summary of 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. 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 our internal reserve engineers.

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 our proved natural gas and oil properties exceeds the fair value and could result in an impairment charge, which would reduce net income.

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, 2023, 2022 or 2021. 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, 2023, 2022 or 2021. 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, 2023, 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 factors including, but not limited to, our 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, 2023, 2022 and 2021, we recorded impairments of $9.6 million, $46.9 million and $79.0 million, respectively, to exploration expense for unproved natural gas and oil properties for which the leases are expected to expire.

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 of the transaction. 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 values 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.

Commodity 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. 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 counterparties' 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.

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 Quantitative and Qualitative Disclosures About Market Risk below and Note 6 of the notes to our consolidated financial statements included in this report for further discussion of our derivative instruments.

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

New Accounting Pronouncements

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

Quantitative and Qualitative Disclosures 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, counterparty credit, 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. In 2023, 2022 and 2021, the average daily Henry Hub spot market price of natural gas was $2.53 per mmbtu, $6.38 per mmbtu and $3.82 per mmbtu, respectively, and the average daily WTI oil price was $77.59 per bbl, $94.33 per bbl and $68.11 per bbl, respectively. Approximately 86% of our December 31, 2023 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 our Credit Facility, 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, 2023, approximately 1,410,000 mmbtu/d of our projected natural gas production for 2024 was hedged at a weighted average floor price of $3.55 per mmbtu, and approximately 1,350,000 mmbtu/d of our projected natural gas production for 2025 was hedged at a weighted average floor price of $3.82 per mmbtu, excluding the sold puts on our three-way collars and sold calls. Additionally, as of December 31, 2023, approximately 10,000 bbls/d of our projected oil production for 2024 was hedged at a weighted average floor price of $75.39 per bbl, and approximately 2,000 bbls/d of our projected oil production for 2025 was hedged at a weighted average floor price of $71.80 per bbl. Our open hedge positions as of December 31, 2023 had maturities extending through December 2026. We also use basis swaps to mitigate portions of our natural gas basis exposure. Our market risk associated with commodity prices did not materially change from December 31, 2022 to December 31, 2023. See Note 6 of the notes to our consolidated financial statements included in this report for a summary of our commodity hedge position as of December 31, 2023.

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, 2023. 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	$ (358,555)	$ 361,730
Oil	$ (29,960)	$ 30,106
NGL	$ (2,026)	$ 2,038

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 gain (loss).

We expect continued volatility in the fair value of our derivative instruments, and 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. As of December 31, 2023, the estimated fair value of our commodity derivative positions was a net asset of $711.3 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. See Note 6, *Credit Risk*, of the notes to our consolidated financial statements included in this report for further discussion of our credit risk.

Customer Credit Risk

We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables; however, we do not believe the loss of any single customer would materially impact our operating results. We also have joint interest receivables, which arise from billings to entities that own working interests in the wells we operate, but historically we have not incurred any material losses.

Interest Rate Risk

Our Credit Facility bears interest at floating rates which exposes us to interest rate risk. As of December 31, 2023, borrowings under our Credit Facility bore interest at the 1-month SOFR plus 0.10%, plus an applicable margin ranging from 1.75% to 2.75% per annum based on Credit Facility utilization. For the year ended December 31, 2023, our Credit Facility had a weighted average interest rate of 7.44%. A 1.00% increase in the interest rate on our Credit Facility during the year ended December 31, 2023 would have resulted in an estimated total increase of $7.2 million in interest expense on associated borrowings. We have entered into interest rate swaps through the end of 2024 to mitigate a portion of our exposure to interest rate volatility. See Note 6 of the notes to our consolidated financial statements included in this report for further discussion of our interest rate derivatives.

Report of Independent Auditors

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

Opinion

We have audited the accompanying consolidated financial statements of Ascent Resources Utica Holdings, LLC and its subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2023 and 2022, 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, 2023, including the related notes (collectively referred to as the "consolidated financial statements").

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2023 in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audit in accordance with auditing standards generally accepted in the United States of America (US GAAS). Our responsibilities under those standards are further described in the Auditors' Responsibilities for the Audit of the Consolidated Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audit. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management 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, and for 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.

In preparing the consolidated financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date the consolidated financial statements are available to be issued.

Auditors' Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with US GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the consolidated financial statements.

In performing an audit in accordance with US GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the consolidated financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements.
- Obtain an understanding of internal control relevant to the audit 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, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the consolidated financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company’s ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

Other Information

Management is responsible for the other information included in the annual report. The other information comprises Business Overview, Properties, Management’s Discussion and Analysis of Financial Condition and Results of Operations, and Quantitative and Qualitative Disclosures About Market Risk, but does not include the consolidated financial statements and our auditors' report thereon. Our opinion on the consolidated financial statements does not cover the other information, and we do not express an opinion or any form of assurance thereon.

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information and consider whether a material inconsistency exists between the other information and the consolidated financial statements or the other information otherwise appears to be materially misstated. If, based on the work performed, we conclude that an uncorrected material misstatement of the other information exists, we are required to describe it in our report.

PricewaterhouseCoopers LLP

Oklahoma City, Oklahoma
March 7, 2024

ASCENT RESOURCES UTICA HOLDINGS, LLC
CONSOLIDATED BALANCE SHEETS

($ in thousands)	December 31, 2023	December 31, 2022
Current Assets:		
Cash and cash equivalents	$ 6,718	$ 3,894
Accounts receivable – natural gas, oil and NGL sales[(a)]	266,906	530,385
Accounts receivable – joint interest and other	38,540	35,340
Short-term derivative assets	438,041	14,061
Other current assets	10,620	12,597
Total Current Assets	760,825	596,277
Property and Equipment:		
Natural gas and oil properties, based on successful efforts accounting	11,565,453	10,558,533
Other property and equipment	42,542	39,641
Less: accumulated depreciation, depletion and amortization	(4,619,852)	(3,900,730)
Property and Equipment, net	6,988,143	6,697,444
Other Assets:		
Long-term derivative assets	288,396	6,081
Other long-term assets	68,486	44,117
Total Assets	$ 8,105,850	$ 7,343,919
Current Liabilities:		
Accounts payable	$ 76,333	$ 77,753
Accrued interest	44,665	50,375
Short-term derivative liabilities	13,157	684,204
Other current liabilities[(b)]	551,894	771,062
Total Current Liabilities	686,049	1,583,394
Long-Term Liabilities:		
Long-term debt, net	2,533,873	2,475,222
Long-term derivative liabilities	—	495,464
Other long-term liabilities	124,565	113,061
Total Long-Term Liabilities	2,658,438	3,083,747
Commitments and contingencies (Note 11)		
Member's Equity	4,761,363	2,676,778
Total Liabilities and Member's Equity	$ 8,105,850	$ 7,343,919

(a) Including related party amounts of $10.2 million and $12.4 million as of December 31, 2023 and 2022, respectively.
(b) Including related party amounts of $106.5 million and $98.0 million as of December 31, 2023 and 2022, respectively.

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, 2023	2022	2021
Revenues:			
Natural gas	$ 1,770,416	$ 4,700,531	$ 2,510,150
Oil	257,708	246,866	188,076
NGL[(a)]	198,018	239,071	241,731
Commodity derivative gain (loss)	2,098,185	(2,687,817)	(1,743,892)
Total Revenues	4,324,327	2,498,651	1,196,065
Operating Expenses:			
Lease operating expenses	123,212	101,659	81,822
Gathering, processing and transportation expenses[(b)]	975,245	979,987	945,031
Taxes other than income	47,372	45,724	38,988
Exploration expenses	12,625	49,142	83,367
General and administrative expenses	90,930	77,112	58,334
Depreciation, depletion and amortization	723,951	676,053	598,407
Total Operating Expenses	1,973,335	1,929,677	1,805,949
Income (Loss) from Operations	2,350,992	568,974	(609,884)
Other Income (Expense):			
Interest expense, net	(205,910)	(209,731)	(174,840)
Change in fair value of contingent payment right	(2,570)	(3,302)	(19,921)
Losses on purchases or exchanges of debt	(26,900)	—	(3,822)
Other income	12,727	5,438	2,182
Total Other Expense	(222,653)	(207,595)	(196,401)
Net Income (Loss)	$ 2,128,339	$ 361,379	$ (806,285)

(a) Including related party amounts of $46.4 million, $91.6 million and $109.7 million during the years ended December 31, 2023, 2022 and 2021, respectively.

(b) Including related party amounts of $665.7 million, $643.8 million and $620.3 million during the years ended December 31, 2023, 2022 and 2021, respectively.

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

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

	Year Ended December 31,		
($ in thousands)	2023	2022	2021
Balance, Beginning of Period	$ 2,676,778	$ 2,296,808	$ 3,102,590
Contributions from Member	3,695	22,745	3,737
Distributions to Member	(47,449)	(4,154)	(3,234)
Net income (loss)	2,128,339	361,379	(806,285)
Balance, End of Period	$ 4,761,363	$ 2,676,778	$ 2,296,808

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, 2023	2022	2021
Cash Flows from Operating Activities:			
Net income (loss)	$ 2,128,339	$ 361,379	$ (806,285)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	723,951	676,053	598,407
(Gain) loss on commodity derivatives	(2,098,185)	2,687,817	1,743,892
Settlements of commodity derivatives	222,549	(1,868,139)	(812,328)
Impairment of unproved natural gas and oil properties	9,640	46,902	78,993
Non-cash interest expense	23,677	16,851	18,301
Long-term incentive compensation	3,695	22,745	3,616
Change in fair value of contingent payment right	2,570	3,302	19,921
Losses on purchases or exchanges of debt	26,038	—	3,810
Other	(1,249)	42	160
Changes in operating assets and liabilities			
(Increase) decrease in accounts receivable and other assets	240,713	(96,350)	(249,315)
Increase (decrease) in accounts payable, liabilities and other	(134,679)	191,410	161,465
Net Cash Provided by Operating Activities	1,147,059	2,042,012	760,637
Cash Flows from Investing Activities:			
Natural gas and oil capital expenditures	(1,056,348)	(962,335)	(597,671)
Cash paid for acquisition	—	(250,882)	—
Additions to other property and equipment	(2,769)	(2,096)	(1,444)
Net Cash Used in Investing Activities	(1,059,117)	(1,215,313)	(599,115)
Cash Flows from Financing Activities:			
Proceeds from Credit Facility borrowings	2,240,000	4,245,000	2,100,000
Repayment of Credit Facility borrowings	(1,845,000)	(4,370,000)	(2,558,000)
Proceeds from issuance of long-term debt	210,000	—	400,000
Repayment of long-term debt	(549,822)	(2,970)	(84,173)
Cash paid for debt issuance and amendment costs	(11,219)	(16,855)	(7,229)
Cash paid for debt prepayment costs	(27,491)	—	—
Cash paid for settlements of commodity derivatives	(53,530)	(378,270)	(11,188)
Cash paid to restructure commodity derivatives	—	(300,000)	—
Cash paid to Member for Member's equity distributions	(25,003)	—	—
Cash paid to Member for Member's long-term incentive Cash Awards	(17,856)	—	—
Other	(5,197)	(5,384)	(4,101)
Net Cash Used in Financing Activities	(85,118)	(828,479)	(164,691)
Net Increase (Decrease) in Cash and Cash Equivalents	2,824	(1,780)	(3,169)
Cash and Cash Equivalents, Beginning of Period	3,894	5,674	8,843
Cash and Cash Equivalents, End of Period	$ 6,718	$ 3,894	$ 5,674
Supplemental disclosures of cash flow information:			
Interest paid, net of capitalized interest	$ 191,541	$ 187,988	$ 142,576
Supplemental disclosures of significant non-cash investing and financing activities:			
Increase (decrease) in accrued capital expenditures	$ (32,502)	$ 2,436	$ 72,025
Financing commodity derivative settlements	$ —	$ 53,530	$ —
Contributions from Member	$ 3,695	$ 22,745	$ 3,737

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

ASCENT RESOURCES UTICA HOLDINGS, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of Presentation and Summary of Significant Accounting Policies

Description of Company

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.

Basis of Presentation and Principles of Consolidation

Our accompanying consolidated financial statements and notes were prepared in accordance with United States GAAP. All material intercompany balances and transactions have been eliminated.

Business Segment Information

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 assess performance. Based on an evaluation of how we are organized and managed, we have identified only one operating segment, which is the exploration, development and production of natural gas, oil and NGL in the United States. We have a single, company-wide management team that manages all properties as a whole rather than by various 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 amounts reported herein. Actual amounts could differ significantly from these estimates, and changes in these estimates are recorded when known. Estimates of natural gas, oil and NGL reserves 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. Other items in our consolidated financial statements that involve the use of significant estimates include asset acquisitions, derivative assets and liabilities, accrued revenue, litigation, commitments and other contingencies.

Summary of 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 as of December 31, 2023 and 2022 were $305.4 million and $565.7 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, and all attempts to collect the balance are exhausted, they would generally be written off against the allowance for doubtful accounts. All accounts receivable are considered to be fully collectible; therefore, no allowance for doubtful accounts has been recorded in the consolidated balance sheets as of December 31, 2023 or 2022.

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 this method, the costs of undeveloped leases and the costs incurred to acquire, drill and complete development and productive 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. 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. We did not incur any exploratory drilling costs in the years ended December 31, 2023, 2022 or 2021.

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, which is based on discounted future cash flows utilizing assumptions typical of third-party market participants. No impairment of proved natural gas and oil properties was recorded for the years ended December 31, 2023, 2022 or 2021. 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, 2023, 2022 and 2021, we recorded impairments of $9.6 million, $46.9 million and $79.0 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. DD&A expense for natural gas and oil properties was $720.1 million, $673.0 million and $595.5 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Other Property and Equipment. Other property and equipment is recorded at cost. 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 $3.8 million, $3.1 million and $2.9 million for the years ended December 31, 2023, 2022 and 2021, respectively. 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, recorded to other income on the consolidated statements 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.

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 liability for a retirement obligation in the period in which a natural gas or oil well is acquired or spud and accrete it to its expected settlement value over time, 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 $16.7 million and $12.4 million as of December 31, 2023 and 2022, 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 and Amendment 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 associated with term debt is recorded in interest expense on the consolidated statements of operations.

Debt issuance and amendment costs associated with our 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 and amendment costs associated with our 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.

Credit and Concentration Risk. We are subject to credit risk resulting from the concentration of our natural gas, oil and NGL receivables. If our largest customers stopped purchasing our natural gas, oil or NGL, our revenues could decline and our operating results and financial condition could be adversely affected. We did not have any concentration of sales to any individual customers that constituted 10% or more of our revenues, before the effect of derivatives, for the year ended December 31, 2022. The following table provides the concentration of sales to individual customers that constituted 10% or more of our revenues, before the effects of derivatives, for the years ended December 31, 2023 and 2021:

	% of Sales
Year Ended December 31, 2023	
Company A	11 %
Year Ended December 31, 2021	
Company A	11 %
Company B	14 %

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 we transact with numerous customers in our operating region. We historically have not incurred any material 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 any material losses on our joint interest receivables.

By using derivative instruments, we are also exposed to credit risk associated with our hedge counterparties. To minimize such risk, we enter into derivative contracts with multiple counterparties, reducing our exposure to any individual counterparty. In addition, we only enter into derivative contracts with counterparties that we determine are creditworthy, and such creditworthiness is subject to periodic review. Any non-performance risk is considered in the valuation of our derivative instruments, but to date it has not had a material impact on the values of our derivatives. See Note 6 for further discussion of our derivative instruments.

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. See Note 7 for further discussion of our fair value measurements.

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 counterparties' 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. See Note 6 for further discussion of our derivative instruments.

Long-Term Incentive Compensation. We recognize compensation cost for equity-classified restricted stock units 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 restricted stock units is recognized once it becomes probable that such awards will be settled. 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 until the settlement date. Long-term incentive compensation associated with restricted stock units is presented as general and administrative expenses on the consolidated statements of operations. See Note 8 for further discussion of our long-term incentive compensation.

Leases. We capitalize our leases to our consolidated balance sheet through a right-of-use ("ROU") asset and a corresponding lease liability. ROU assets associated with our operating leases are presented net within other long-term assets and consist of drilling rigs, real estate, compressors and other equipment, with corresponding lease liabilities reflected as other current liabilities and other long-term liabilities on the consolidated balance sheets. ROU assets associated with our financing leases are reflected as other property and equipment and consist of commercial vehicles, with corresponding lease liabilities reflected as other current liabilities and other long-term liabilities on the consolidated balance sheets. Short-term leases that have an initial term of one year or less are not capitalized to the consolidated balance sheet, and instead are recognized as lease costs in accordance with the lease terms. As of December 31, 2023 and 2022, we were not a lessor.

Our leases are recognized at the commencement date of an arrangement and the associated ROU assets and lease liabilities are based on the present value of the minimum lease payments over the lease term. Most leases do not provide an implicit interest rate; therefore, we use our incremental borrowing rate, based on information available at the inception date, to determine the present value of the lease payments. Certain leases may also contain variable payments. Variable payments that do not depend on an index or rate are excluded from lease payments at lease commencement for initial measurement. Subsequent to initial measurement, these variable payments are recognized in the period in which the obligation for the payment is incurred.

Certain leases include options to renew on a month-to-month basis; however, they are not recognized as part of the ROU assets or lease liabilities as they are not reasonably certain to be exercised.

We have made an accounting policy election to combine lease and non-lease components on an asset class basis, which allows us to account for them as a single lease component. See Note 10 for further information on our leases.

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 immaterial reclassifications have been made to our 2022 and 2021 consolidated financial statements to conform to the presentation used for the 2023 consolidated financial statements.

Adopted and Recently Issued Accounting Pronouncements

In November 2023, the Financial Accounting Standards Board ("FASB") issued ASU 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*. This ASU requires enhanced segment disclosures for public entities, including on an annual and interim basis, significant segment expenses that are regularly provided to the chief operating decision maker and included within each reported measure of segment profit or loss, and that public entities that have only a single reportable segment provide all the disclosures required under this ASU and Topic 280, among other things. The amendments are effective for annual reporting periods beginning after December 15, 2023, and interim periods within annual periods beginning after December 15, 2024. The amendments in this guidance should be applied retrospectively to all prior periods presented in the financial statements. The adoption of this guidance is not expected to have a material impact on our financial statements and related disclosures.

Subsequent Events

As of March 7, 2024, the date the consolidated financial statements were issued, we completed our evaluation of material subsequent events for disclosure, and such items are disclosed herein. See Note 6 for a discussion of our recent hedging transactions.

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. We typically receive payment for natural gas, oil and NGL sales within 30 days of the month of delivery. Under our natural gas, oil and NGL sales contracts, we generally consider the delivery of each mmbtu or bbl to be a separate performance obligation that is satisfied upon 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 accounting guidance for revenue recognition.

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, we have no contract assets or contract liabilities associated with our revenues from contracts with customers. As of December 31, 2023 and 2022, receivables from contracts with customers were $266.9 million and $530.4 million, respectively, and were reported in accounts receivable – natural gas, oil and NGL sales on the consolidated balance sheets.

3. Acquisition

On August 5, 2022, we acquired assets in Ohio for a total purchase price of $270.0 million, or $250.9 million after closing purchase price adjustments. The transaction was financed with a combination of cash on hand and borrowings under our Credit Facility. The assets acquired were primarily producing properties which included approximately 57 net producing wells and 22,300 net acres. The transaction was accounted for as an asset acquisition.

4. Property and Equipment

Net property and equipment included the following as of the dates indicated:

($ in thousands)	December 31, 2023	December 31, 2022
Proved natural gas and oil properties	$ 10,975,699	$ 9,884,342
Unproved natural gas and oil properties	589,754	674,191
Other property and equipment	42,542	39,641
Total Property and Equipment	11,607,995	10,598,174
Accumulated depreciation, depletion and amortization	(4,619,852)	(3,900,730)
Property and Equipment, net	$ 6,988,143	$ 6,697,444

As of December 31, 2023 and 2022, we did not have any capitalized well costs associated with exploratory wells that were pending determination of proved reserves.

5. Debt

Our long-term debt consisted of the following as of the dates indicated:

($ in thousands)	December 31, 2023	December 31, 2022
Credit Facility[(a)]	$ 765,000	$ 370,000
Second lien term loans due November 2025[(b)]	—	549,822
7.00% senior notes due November 2026	597,000	597,000
9.00% senior notes due November 2027	348,294	348,294
8.25% senior notes due December 2028	512,637	300,000
5.875% senior notes due June 2029	400,000	400,000
Unamortized debt discounts and issuance costs	(89,058)	(89,894)
Total Long-Term Debt, net	$ 2,533,873	$ 2,475,222

(a) The interest rate was 7.45% and 6.47% as of December 31, 2023 and 2022, respectively.

(b) We prepaid the outstanding principal amount in May 2023. See below for discussion regarding the transaction. The interest rate was 12.94% as of December 31, 2022.

Credit Facility

Our $3.0 billion Credit Facility matures on June 30, 2027, and as of December 31, 2023, it had an elected commitment of $2.0 billion, of which $250.0 million was authorized for letters of credit. The maturity date will accelerate to August 2, 2026 if an amount greater than or equal to $150.0 million of our 2026 Notes is outstanding as of that date. Our Credit Facility is secured by liens on substantially all of our assets, including our natural gas and oil properties. The borrowing base under our Credit Facility is subject to a semiannual redetermination on or about April 1 and October 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 our 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 2023, we reaffirmed the current borrowing base under our Credit Facility of $3.0 billion and the elected commitments of $2.0 billion. As of December 31, 2023, we had $765.0 million of borrowings outstanding and $169.1 million of letters of credit issued under our Credit Facility.

Under our Credit Facility, we may borrow either term benchmark loans or alternate base rate loans, and as of December 31, 2023, all of the borrowings under our Credit Facility were term benchmark loans. Term benchmark loans bear interest at a rate per annum equal to SOFR plus 0.10%, plus an applicable margin ranging from 1.75% to 2.75% per annum based on Credit Facility utilization. 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. We were subject to an interest rate of 7.45% per annum as of December 31, 2023.

Under our Credit Facility, we are subject to commitment fees payable to the administrative agent for the unutilized portion of our available elected commitment, the rate of which ranges from 0.375% to 0.50% based on Credit Facility utilization. Additionally, we are subject to letter of credit participation fees payable to the administrative agent which escalate based on applicable margins, ranging from 1.75% to 2.75% per annum, in accordance with our 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.

We had $16.5 million and $21.2 million in unamortized debt issuance and amendment costs associated with our Credit Facility as of December 31, 2023 and 2022, respectively, which are presented as part of other long-term assets on the consolidated balance sheets.

Second Lien Term Loans

Our 2025 Second Lien Term Loans had a maturity date of November 1, 2025, and interest was payable quarterly at an annual rate of 9.00% plus 3-month LIBOR, with a 1.00% LIBOR floor. In May 2023, we prepaid the outstanding aggregate principal amount of our 2025 Second Lien Term Loans at a price of 105.00% for $577.3 million, plus accrued and unpaid interest (the “2025 Prepayment”) utilizing borrowings from our Credit Facility. Subsequently, we issued an additional $212.6 million in aggregate principal amount of our existing 2028 Notes (the “2028 Add-On Notes”) to certain former holders of our 2025 Second Lien Term Loans and used the $210.0 million of proceeds to partially repay borrowings under our Credit Facility. This resulted in $210.0 million of the 2025 Prepayment being accounted for as a debt modification with no gain or loss recognized. The remaining portion of the 2025 Prepayment was treated as an extinguishment of debt, resulting in a loss on purchase of debt of $26.9 million which included a proportionate amount of the prepayment premium, unamortized discounts and debt issuance costs.

Senior Notes

2026 Notes. Our 2026 Notes mature on November 1, 2026, and interest is payable on May 1 and November 1 of each year. We may redeem at any point some or all of the 2026 Notes at redemption prices ranging from 101.167% to 100.00%, plus accrued and unpaid interest up to, but excluding, the redemption date. Upon the occurrence of a change of control (as defined in the indenture that governs the 2026 Notes), 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. Our 2027 Notes mature on November 1, 2027, and interest is payable on May 1 and November 1 of each year. 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 that governs the 2027 Notes) and (ii) on or after November 1, 2026, at a redemption price equal to 100.00% of the principal amount of 2027 Notes to be redeemed, in each case plus accrued and unpaid interest up to, but excluding, the redemption date and subject to the issuance of a CVR (defined below). 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 at redemption prices ranging from 104.50% to 100.00%, in each case plus accrued and unpaid interest up to, but excluding, the redemption date. Upon the occurrence of a change of control (as defined in the indenture that governs the 2027 Notes), 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 equal to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if certain triggering events as defined in the agreement (each a “Triggering Event”) occur. Triggering Event is defined to include a qualified public offering, a qualified merger or consolidation that results in our Parent’s equity holders receiving an equity interest that is listed or quoted on any national securities exchange, or a change of control. The contingent payment right is required to be bifurcated and accounted for at fair value, and the estimated fair value was $91.1 million and $88.5 million as of December 31, 2023 and 2022, respectively, and is presented as part of other long-term liabilities on the consolidated balance sheets. See Note 7, *Contingent Payment Right*, 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 a Triggering Event despite no longer holding the associated 2027 Notes. However, if any of the 2027 Notes are voluntarily sold to us prior to a Triggering Event through means of open market transactions or other negotiated transactions, the associated contingent payment right will expire.

2028 Notes. Our 2028 Notes mature on December 31, 2028, and interest is payable on February 1 and August 1 of each year. We may redeem at any point some or all of the 2028 Notes at redemption prices ranging from 104.125% to 100.00% plus accrued and unpaid interest up to, but excluding, the redemption date. Upon the occurrence of a change of control (as defined in the indenture that governs the 2028 Notes), 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. In May 2023, we issued the 2028 Add-On Notes, discussed above. These notes have the same terms and form a single series with our existing 2028 Notes.

2029 Notes. Our 2029 Notes mature on June 30, 2029, and interest is payable on March 1 and September 1 of each year. We may redeem some or all of the 2029 Notes at redemption prices ranging from 102.938% to 100.00% at any time on or after September 1, 2024, plus accrued and unpaid interest up to, but excluding, the redemption date. At any time prior to September 1, 2024, we may redeem some or all of the 2029 Notes at a price of 100.00% plus a make-whole premium (as defined in the indenture that governs the 2029 Notes), and we may redeem up to 40% of the aggregate principal amount of 2029 Notes at a price of 105.875% 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 change of control (as defined in the indenture that governs the 2029 Notes), we are required to offer to repurchase all or any part of the 2029 Notes at a price of 101.00%, plus accrued and unpaid interest.

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

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. Our 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 by the Credit Facility) of not more than 3.50 to 1.00 for each fiscal quarter and (ii) a modified current ratio (as defined by the Credit Facility), 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, 2023.

Debt Maturities

The principal amount of debt maturities for the five years ended after December 31, 2023 and thereafter are as follows:

($ in thousands)	Principal Amount of Debt Securities
2024	$ —
2025	—
2026	597,000
2027	1,113,294
2028	512,637
2029 and Thereafter	400,000
Total	$ 2,622,931

6. 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. We utilize the following types of derivative 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 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, Eastern Gas South, TCO, Tetco M-2, Trunkline Zone 1A and Tenn Z4-200. 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.

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 are recorded in earnings as we have not elected hedge accounting for any of our derivative instruments.

The following table sets forth the average volumes per day associated with our outstanding natural gas derivative instruments as of December 31, 2023, 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:						$ 588,248
2024	1,280,000	$ 3.54				
2025	880,000	$ 3.94				
2026	705,000	$ 4.07				
Collars:						108,931
2024	100,000		$ 4.57	$ 3.43		
2025	400,000		$ 5.88	$ 3.52		
2026	190,000		$ 5.22	$ 3.86		
Three-way collars:						27,675
2024	30,000		$ 6.39	$ 4.25	$ 3.00	
2025	70,000		$ 5.42	$ 4.04	$ 2.79	
2026	70,000		$ 5.65	$ 4.04	$ 2.79	
Call options:						(43,265)
2024	375,000		$ 2.89			
2025	40,000		$ 4.08			
Basis swaps:						9,239
2024	1,117,000	$ (0.40)				
2025	629,000	$ (0.37)				
2026	10,000	$ (0.18)				
Total Estimated Fair Value						$ 690,828

The following table sets forth the average volumes per day associated with our outstanding oil derivative instruments as of December 31, 2023, the contracted weighted average oil prices and the estimated fair values:

	Average Volume (bbls/d)	Weighted Average Prices ($/bbl) Swap Strike Price	Fair Value ($ in thousands)
Oil:			
Swaps:			$ 16,972
2024	10,000	$ 75.39	
2025	2,000	$ 71.80	
Total Estimated Fair Value			$ 16,972

In January 2024, we restructured a portion of our 2025 oil swaps and our 2026 natural gas swaps and collars in exchange for $81.2 million in cash, which was used to repay a portion of the borrowings outstanding under our Credit Facility. The restructuring resulted in a reduction to the weighted average strike prices of our 2025 oil swaps and 2026 natural gas swaps to approximately $70.00 per bbl and $3.75 per mmbtu, respectively. Additionally, the spread on our 2026 natural gas collars was adjusted, resulting in an average ceiling price of $5.32 per mmbtu and an average floor price of $3.53 per mmbtu.

The following table sets forth the average volumes per day associated with our outstanding NGL derivative instruments as of December 31, 2023, the contracted weighted average NGL prices and the estimated fair values:

		Weighted Average Prices ($/bbl)	
	Average Volume (bbls/d)	Swap Strike Price	Fair Value ($ in thousands)
NGL:			
Swaps - Propane:			$ 3,451
2024	2,000	$ 33.39	
Total Estimated Fair Value			$ 3,451

The following table sets forth the notional amounts associated with our outstanding interest rate derivative instruments as of December 31, 2023, 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	Fair Value
Interest Rate:				
Swaps:				$ 2,029
2024	$ 200,000	3.7695 %	1-month SOFR	
Total Estimated Fair Value				$ 2,029

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, 2023 and 2022:

	December 31, 2023		
($ in thousands) **Consolidated Balance Sheet Presentation**	Fair Value, Gross	Amounts Netted on Balance Sheet	Fair Value, Net
Short-term derivative assets:			
Commodity derivatives	$ 519,938	$ (83,926)	$ 436,012
Interest rate derivatives	9,441	(7,412)	2,029
Total short-term derivative assets	$ 529,379	$ (91,338)	$ 438,041
Long-term derivative assets:			
Commodity derivatives	$ 423,767	$ (135,371)	$ 288,396
Total long-term derivative assets	$ 423,767	$ (135,371)	$ 288,396
Short-term derivative liabilities:			
Commodity derivatives	$ 97,083	$ (83,926)	$ 13,157
Interest rate derivatives	7,412	(7,412)	—
Total short-term derivative liabilities	$ 104,495	$ (91,338)	$ 13,157
Long-term derivative liabilities:			
Commodity derivatives	$ 135,371	$ (135,371)	$ —
Total long-term derivative liabilities	$ 135,371	$ (135,371)	$ —

	December 31, 2022		
($ in thousands) **Consolidated Balance Sheet Presentation**	**Fair Value, Gross**	**Amounts Netted on Balance Sheet**	**Fair Value, Net**
Short-term derivative assets:			
Commodity derivatives	$ 112,161	$ (102,959)	$ 9,202
Interest rate derivatives	4,859	—	4,859
Total short-term derivative assets	$ 117,020	$ (102,959)	$ 14,061
Long-term derivative assets:			
Commodity derivatives	$ 234,322	$ (228,241)	$ 6,081
Total long-term derivative assets	$ 234,322	$ (228,241)	$ 6,081
Short-term derivative liabilities:			
Commodity derivatives	$ 787,163	$ (102,959)	$ 684,204
Total short-term derivative liabilities	$ 787,163	$ (102,959)	$ 684,204
Long-term derivative liabilities:			
Commodity derivatives	$ 723,705	$ (228,241)	$ 495,464
Total long-term derivative liabilities	$ 723,705	$ (228,241)	$ 495,464

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

	Consolidated Statements	**Year Ended December 31,**		
($ in thousands)	**of Operations Presentation**	**2023**	**2022**	**2021**
Commodity derivatives	Commodity derivative gain (loss)	$ 2,098,185	$ (2,687,817)	$ (1,743,892)
Interest rate derivatives	Interest (expense) income	$ 2,872	$ 5,489	$ (267)

Credit Risk

By using derivative instruments, we are also exposed to credit risk associated with our hedge counterparties. To minimize such risk, we enter into derivative contracts with multiple counterparties, reducing our exposure to any individual counterparty. In addition, 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.

7. Fair Value Measurements

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

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

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

Level 3 – Unobservable inputs that reflect our own assumptions.

Fair Value 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, 2023 and 2022. There were no transfers in or out of our Level 3 fair value measurements.

	Fair Value Measurements as of December 31, 2023:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ —	$ 724,408	$ —	$ 724,408
Interest rate derivatives	—	2,029	—	2,029
Total	$ —	$ 726,437	$ —	$ 726,437
Liabilities:				
Commodity derivatives	$ —	$ 13,157	$ —	$ 13,157
Contingent payment right	—	—	91,095	91,095
Total	$ —	$ 13,157	$ 91,095	$ 104,252

	Fair Value Measurements as of December 31, 2022:			
($ in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ —	$ 15,283	$ —	$ 15,283
Interest rate derivatives	—	4,859	—	4,859
Total	$ —	$ 20,142	$ —	$ 20,142
Liabilities:				
Commodity derivatives	$ —	$ 1,179,668	$ —	$ 1,179,668
Contingent payment right	—	—	88,525	88,525
Total	$ —	$ 1,179,668	$ 88,525	$ 1,268,193

Derivatives. We estimate the fair value of our commodity and interest rate derivatives using models that utilize market-based parameters and are therefore classified as Level 2 fair value measurements. The fair value of our commodity swaps, collars and options are based on standard industry income approach models that use significant observable inputs including, but not limited to, forward curves, discount rates, nonperformance risk and volatilities. We estimate the fair value of our interest rate swaps using a discounted cash flow model utilizing the contracted notional amounts, active market-quoted SOFR yield curves and the applicable credit-adjusted risk-free rate yield curve. See Note 6 for further information regarding our derivative instruments.

Contingent Payment Right. The 2027 Notes contain a contingent payment right which entitles the holders to receive a fixed amount of cash or equity equal to 45% of the then-outstanding aggregate principal amount of 2027 Notes, if a Triggering Event occurs. See Note 5, *2027 Notes*, for further information regarding the contingent payment right. The contingent payment right is required to be bifurcated and accounted for as a liability at fair value. The fair value of the contingent payment right is based on unobservable inputs and is therefore classified as Level 3.

The fair value of the contingent payment right was determined using a “with” and “without” analysis, which compares the value of the 2027 Notes including the contingent payment right to the value of an otherwise identical bond that omits the contingent payment right feature by comparing the discounted cash flows. The significant unobservable inputs used to estimate the fair value of the contingent payment right include the probability of a Triggering Event occurring prior to maturity and the discount rate used in the discounted cash flow analysis. Changes in these inputs impact the fair value measurement of the contingent payment right. For example, an increase or decrease in the probability of a Triggering Event occurring would increase or decrease, respectively, the fair value of the contingent payment right. Additionally, an increase or decrease in the discount rate would decrease or increase, respectively, the fair value of the contingent payment right.

The following table presents quantitative information about Level 3 inputs used in the fair value measurement of the contingent payment right:

	December 31,	
	2023	2022
Probability of a Triggering Event prior to maturity	70%	75%
Discount rate	9.9%	11.1%

The contingent payment right is presented as part of other long-term liabilities on the consolidated balance sheets. Changes in its fair value are presented as a change in fair value of the contingent payment right on the consolidated statements of operations. The following table presents a reconciliation of changes in the fair value of the contingent payment right:

	December 31,	
($ in thousands)	2023	2022
Balance, beginning of period	$ 88,525	$ 85,223
Change in fair value	2,570	3,302
Balance, end of period	$ 91,095	$ 88,525

Fair Value of Debt

The carrying amounts and estimated fair values of our debt instruments as of December 31, 2023 and 2022 are shown in the table below. The fair values were estimated using Level 2 market data inputs. See Note 5 for further information regarding our debt.

	December 31,			
	2023		2022	
($ in thousands)	Carrying Value[(a)]	Fair Value	Carrying Value[(a)]	Fair Value
Credit Facility[(b)]	$ 765,000	$ 765,000	$ 370,000	$ 370,000
2025 Second Lien Term Loans[(c)]	—	—	534,945	586,248
2026 Notes	590,522	598,493	588,542	584,010
2027 Notes	300,470	436,378	291,569	424,296
2028 Notes	482,856	518,737	295,879	297,160
2029 Notes	395,025	372,920	394,287	357,958
Total	$ 2,533,873	$ 2,691,528	$ 2,475,222	$ 2,619,672

(a) Carrying values for our 2025 Second Lien Term Loans and Senior Notes are presented net of unamortized debt issuance costs and debt discounts or premiums.
(b) The carrying value of borrowings under our Credit Facility approximates fair value as the interest rate is based on prevailing market rates.
(c) We prepaid the outstanding principal amount in May 2023. See Note 5 for information regarding the 2025 Prepayment.

8. Long-Term Incentive Compensation

In 2020, our Parent established a long-term incentive plan (the “Plan”) in order to further our growth and success. Under the Plan, the board of managers of our Parent may grant restricted stock units (“RSUs”) and rights to receive cash award payments (“Cash Awards”) to certain of our employees and certain managers of the board of our Parent. The RSUs contain distribution equivalent rights, which entitle participants to cash distributions on unvested RSUs if and to the extent holders of common units receive cash distributions from our Parent. In 2023, our Parent distributed $25.0 million to its unitholders, a portion of which was distributed to holders of unvested RSUs. In conjunction with the initial distribution, our Parent also effected a reverse stock split of its outstanding units at a ratio of 1-for-100 (1:100) (the "Reverse Stock Split").

Under the Plan, as adjusted for the Reverse Stock Split, 3.6 million common units of our Parent were reserved for issuance, and as of December 31, 2023, approximately 770,000 remained available for future grants. Our long-term incentive compensation was $3.7 million, $22.7 million and $3.6 million for the years ended December 31, 2023, 2022 and 2021, respectively. We account for forfeitures during the period in which they occur by reversing the expense previously recognized for such awards.

Time-Vested Awards

Time-Vested Restricted Stock Units. Time-Vested RSUs are accounted for as equity awards, and vesting is subject to a service condition which is generally satisfied over five years in one-year tranches. Long-term incentive 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. Time-Vested RSUs are subject to an accelerated vesting schedule upon certain events which are generally outside of the control of the participant.

A summary of Time-Vested RSU activity for the year ended December 31, 2023 is as follows:

(in thousands, except weighted average fair value)	Time-Vested RSUs[a]	Weighted Average Grant Date Fair Value[a]
Unvested as of December 31, 2022	985	$ 10.91
Granted	35	$ 22.00
Forfeited	(15)	$ 13.71
Vested	(316)	$ 10.62
Unvested as of December 31, 2023	689	$ 11.55

(a) All unit and per unit information has been retroactively adjusted to reflect the Reverse Stock Split.

During the years ended December 31, 2023, 2022 and 2021, respectively, we recognized $3.4 million, $3.4 million and $3.6 million of long-term incentive compensation associated with our Time-Vested RSUs. As of December 31, 2023, there was $5.6 million of unrecognized compensation costs related to unvested Time-Vested RSUs. The unamortized compensation costs are expected to be recognized over a weighted average period of approximately 2.0 years.

Performance-Vested Awards

Performance-Vested Restricted Stock Units. Performance-Vested RSUs are accounted for as liability awards, and vesting is subject to a performance condition which is generally satisfied upon the occurrence of a qualifying liquidity event ("QLE") as defined in the Plan. Upon each QLE, participants are generally entitled to cash payments from our Parent, or upon a QLE by which our Parent becomes a publicly held corporation, common stock in such public entity. We recognize long-term incentive compensation related to the Performance-Vested RSUs at fair value using appropriate valuation techniques on such date it becomes probable that a performance condition will be achieved and remeasure each period at fair value through the date of settlement. Performance-Vested RSUs are subject to an accelerated vesting schedule dependent upon certain events which are generally outside the control of the participant and are also subject to expiration. As of December 31, 2023, it was not probable that a performance condition had, or would be achieved. The ultimate settlement of Performance-Vested RSUs will be partially or fully offset to the extent Cash Awards were previously paid by our Parent as part of the Plan (the "Cash Award Offset Payments") and any corresponding Performance-Vested RSUs will be forfeited to the extent of any such previous Cash Award Offset Payments.

A summary of Performance-Vested RSU activity for the year ended December 31, 2023 is as follows:

(in thousands, except weighted average fair value)	Performance-Vested RSUs[a]	Weighted Average Grant Date Fair Value[a]
Unvested as of December 31, 2022	1,594	$ 10.65
Granted	35	$ 22.00
Forfeited	(27)	$ 12.09
Vested	—	$ —
Unvested as of December 31, 2023	1,602	$ 10.88

(a) All unit and per unit information has been retroactively adjusted to reflect the Reverse Stock Split.

During the year ended December 31, 2023, we recognized $0.3 million of compensation expense associated with the equity distributions made by our Parent to the holders of the Performance-Vested RSUs. No distributions were made during the same periods in 2022 or 2021 and therefore no associated compensation expense was recorded.

Cash Awards. Under the Plan, Cash Awards are triggered and paid by our Parent upon achieving certain leverage ratios, as defined in the Plan, and are determined based on annual free cash flows, also defined in the Plan. If the leverage ratio for a calendar year is between 2.0 times to 1.75 times, or below 1.75 times, the result would be a cash payment from our Parent to participants based on 2.5% or 5.0%, respectively, of annual free cash flow. The Cash Awards will be funded by our Parent following distributions from us in future periods. Cash Awards are limited to a total of five annual payments, after which the opportunity for future Cash Awards is terminated. We account for Cash Awards in accordance with ASC 710, *Compensation*, and long-term incentive compensation is accrued once determined probable and reasonably estimable. During the year ended December 31, 2022, we recognized $17.9 million of long-term incentive compensation associated with the Cash Awards. We did not recognize any long-term incentive compensation associated with the Cash Awards in 2023 or 2021.

9. Related Party Transactions

Natural 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. These amounts are disclosed as footnotes on the face of our consolidated balance sheets and statements of operations.

For information regarding the credit support requirements due to certain related parties, see Note 11, *Pipeline Commitments*.

Long-Term Debt

Long-term debt held by certain related parties included the following as of the dates indicated:

($ in thousands)	December 31, 2023	December 31, 2022
2028 Notes[a]	$ 9,143	$ —
2027 Notes	258	258
2025 Second Lien Term Loans[a]	—	8,600
Total Related Party Long-Term Debt	$ 9,401	$ 8,858

(a) As of December 31, 2023, $9.1 million in aggregate principal amount of our 2028 Notes were held by certain related parties who had held $8.6 million of aggregate principal amount of our 2025 Second Lien Term Loans prior to the 2025 Prepayment in May 2023. See Note 5 for information regarding the 2025 Prepayment and the 2028 Add-On Notes.

10. Leases

We enter into certain agreements for tangible assets, real estate and easements to support our operations. To the extent that we determine an arrangement represents a lease in accordance with ASC 842, *Leases*, we classify that lease as an operating or financing lease. The following table summarizes our ROU assets and lease liabilities on the consolidated balance sheets as of December 31, 2023 and 2022:

($ in thousands)	Consolidated Balance Sheet Presentation	December 31, 2023	December 31, 2022
Operating leases:			
ROU assets, net	Other long-term assets	$ 51,604	$ 22,598
Short-term lease liabilities	Other current liabilities	$ 38,215	$ 14,230
Long-term lease liabilities	Other long-term liabilities	13,203	8,316
Total operating lease liabilities		$ 51,418	$ 22,546
Financing leases:			
ROU assets, net	Property and equipment, net	$ 4,579	$ 1,958
Short-term lease liabilities	Other current liabilities	$ 1,532	$ 720
Long-term lease liabilities	Other long-term liabilities	1,909	725
Total financing lease liabilities		$ 3,441	$ 1,445

The following table summarizes our total lease costs before amounts are recovered from our joint interest partners, where applicable, for the periods presented:

($ in thousands)	Consolidated Financial Statement Presentation	Year Ended December 31, 2023	2022	2021
Operating lease cost:				
Operating lease cost	General and administrative expense	$ 1,868	$ 1,792	$ 1,881
Operating lease cost	Gathering, processing and transportation[(a)]	22,415	12,472	10,142
Operating lease cost	Lease operating expense	96	96	338
Operating lease cost	Natural gas and oil properties[(b)]	42,834	30,084	28,673
Total operating lease cost		$ 67,213	$ 44,444	$ 41,034
Financing lease cost:				
Amortization of ROU assets	DD&A	$ 1,458	$ 1,123	$ 1,024
Interest on lease liabilities	Interest expense	120	42	43
Total financing lease cost		$ 1,578	$ 1,165	$ 1,067

(a) Includes short-term lease costs of $7.4 million, $5.0 million and $4.8 million for the years ended December 31, 2023, 2022 and 2021, respectively.

(b) Includes short-term and variable lease costs of $35.8 million, $7.0 million and $17.4 million for the years ended December 31, 2023, 2022 and 2021, respectively.

Additional information for our operating and financing leases is summarized below:

	Year Ended December 31,					
	2023		2022		2021	
($ in thousands)	Operating	Financing	Operating	Financing	Operating	Financing
Cash outflows for lease liabilities:						
Operating cash flows	$ 16,356	$ 119	$ 9,388	$ 42	$ 7,605	$ 43
Investing cash flows	$ 7,325	$ —	$ 22,943	$ —	$ 11,095	$ —
Financing cash flows	$ —	$ 2,084	$ —	$ 1,256	$ —	$ 998
Non-cash activities:						
ROU assets obtained in exchange for lease liabilities	$ 50,710	$ 4,084	$ 19,121	$ 1,589	$ 35,100	$ 1,031

	December 31, 2023		December 31, 2022	
	Operating	Financing	Operating	Financing
Weighted average remaining lease term (in years)	1.5	2.4	1.7	2.2
Weighted average discount rate	6.8 %	6.7 %	3.6 %	3.9 %

The following table presents our maturity analysis as of December 31, 2023 for future lease expirations. We do not have any lease maturities after 2026.

	December 31, 2023	
($ in thousands)	Operating	Financing
2024	$ 40,556	$ 1,714
2025	11,341	1,304
2026	2,452	724
Total lease payments	54,349	3,742
Less: imputed interest	(2,931)	(301)
Present value of lease liabilities	$ 51,418	$ 3,441

11. 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 9, 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, we have accrued $22.2 million and $2.3 million, respectively, as of December 31, 2023 and 2022, which is presented as part of other current liabilities on the consolidated balance sheets. 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.

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 volumes at negotiated rates or pay for any deficiencies. The table below presents our undiscounted pipeline commitments that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2023 and represents 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.

($ in thousands)	Pipeline Commitments
2024	$ 683,781
2025	675,594
2026	671,768
2027	656,553
2028	624,492
2029 and Thereafter	3,816,314
Total	$ 7,128,502

To satisfy credit support requirements for these commitments, $169.1 million in letters of credit and $260.4 million in surety bonds were issued by us or on our behalf to certain transportation providers as of December 31, 2023. Our credit support includes support provided to certain related parties, which, as of December 31, 2023, included $120.5 million in letters of credit and $196.8 million in surety bonds. For information regarding certain other transactions with related parties, see Note 9.

12. Other Current Liabilities

Our other current liabilities consisted of the following as of the dates indicated:

	December 31,	
($ in thousands)	2023	2022
Revenues and royalties due others	$ 185,885	$ 272,000
Gathering, processing and transportation expense accrual	146,416	135,421
Drilling and completion cost accrual	63,402	102,871
Operating and financing leases	39,747	14,950
Taxes other than income accrual	35,014	31,556
General and administrative expenses	23,776	20,020
Lease operating expense accrual	9,297	11,826
Derivative liability	1,438	170,178
Other	46,919	12,240
Total Other Current Liabilities	$ 551,894	$ 771,062

13. 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)	**2023**	**2022**
Proved	$ 10,975,699	$ 9,884,342
Unproved	589,754	674,191
Total	11,565,453	10,558,533
Accumulated depreciation, depletion and amortization	(4,596,294)	(3,877,227)
Net Capitalized Costs	$ 6,969,159	$ 6,681,306

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)	**2023**	**2022**	**2021**
Acquisition costs of properties:			
Proved properties	$ 881	$ 240,032	$ 2,624
Unproved properties	152,760	132,437	91,801
Total property acquisition costs	153,641	372,469	94,425
Exploration costs	2,905	2,187	3,049
Development costs	862,919	849,087	577,805
Total	$ 1,019,465	$ 1,223,743	$ 675,279

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)	**2023**	**2022**	**2021**
Revenues, excluding the effects of commodity derivatives	$ 2,226,142	$ 5,186,468	$ 2,939,957
Lease operating expenses	(123,212)	(101,659)	(81,822)
Gathering, processing and transportation expenses	(975,245)	(979,987)	(945,031)
Taxes other than income	(47,372)	(45,724)	(38,988)
Exploration expenses	(12,625)	(49,142)	(83,367)
Natural gas and oil depreciation, depletion and amortization	(720,103)	(673,003)	(595,481)
Results of Operations	$ 347,585	$ 3,336,953	$ 1,195,268

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.

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 estimates are revised, as warranted by additional performance data. Our proved natural gas, oil and NGL reserves for the years ended December 31, 2023, 2022 and 2021 were prepared by our internal reserve engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI") utilizing data we compiled. The information provided below related to our natural gas, oil and NGL reserves is presented in accordance with regulations prescribed by the SEC.

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)
Proved Reserves as of December 31, 2020	8,073,034	42,613	110,361	8,990,875
Extensions, discoveries and other additions	735,688	6,707	15,384	868,234
Revisions	46,756	1,502	5,349	87,862
Production	(645,752)	(3,110)	(7,012)	(706,484)
Proved Reserves as of December 31, 2021	8,209,726	47,712	124,082	9,240,487
Extensions, discoveries and other additions	614,095	1,766	5,234	656,094
Revisions	(607,465)	(7,368)	29,481	(474,785)
Purchases of reserves	218,662	42	215	220,206
Production	(719,470)	(2,814)	(5,794)	(771,119)
Proved Reserves as of December 31, 2022	7,715,548	39,338	153,218	8,870,883
Extensions, discoveries and other additions	705,497	8,577	33,652	958,868
Revisions	(32,718)	1,589	(23,462)	(163,953)
Production	(712,691)	(3,739)	(7,384)	(779,429)
Proved Reserves as of December 31, 2023	7,675,636	45,765	156,024	8,886,369
Proved developed reserves:				
December 31, 2021	4,493,267	14,587	51,594	4,890,355
December 31, 2022	5,101,803	16,687	63,026	5,580,079
December 31, 2023	5,471,996	19,079	75,155	6,037,398
Proved undeveloped reserves:				
December 31, 2021	3,716,459	33,124	72,488	4,350,132
December 31, 2022	2,613,745	22,651	90,192	3,290,804
December 31, 2023	2,203,640	26,686	80,869	2,848,971

During the year ended December 31, 2023, we added approximately 958.9 bcfe in proved reserves through the continued development of our Utica Shale acreage. Downward revisions of previous estimates of approximately 164.0 bcfe included (i) a decrease of 79.3 bcfe due to change in price, and (ii) a decrease of 84.7 bcfe primarily due to the removal of PUDs where it was determined development would occur beyond five-years from the PUD booking, net of additions of previously proved locations that were added to our current five-year development plan, and development plan optimization. As of December 31, 2023, all proved undeveloped locations were in accordance with the SEC five-year rule. A majority of the PUDs removed from the proved undeveloped category as of December 31, 2023 are expected to be developed in our current five-year development plan as we continue to optimize through active leasing and extending laterals. The average adjusted prices used to calculate reserves as of December 31, 2023 were $2.23 per mcf for natural gas, $70.40 per bbl for oil and $24.05 per bbl of NGL utilizing a benchmark of $2.64 per mmbtu of natural gas and $78.21 per bbl of oil and condensate.

During the year ended December 31, 2022, we added approximately 656.1 bcfe in proved reserves through the continued development of our Utica Shale acreage. Downward revisions of previous estimates of approximately 474.8 bcfe included a decrease of 251.9 bcfe primarily due to negative performance revisions and a decrease of 222.9 bcfe in PUD revisions primarily due to the removal of PUDs that were not going to be developed within the SEC's five-year rule, although the majority remain in our current five-year development plan. As of December 31, 2022, all proved undeveloped locations were in accordance with the SEC five-year rule. We also added approximately 220.2 bcfe of proved reserves through our Ohio asset acquisition. The average adjusted prices used to calculate reserves as of December 31, 2022 were $6.26 per mcf for natural gas, $87.39 per bbl for oil and $39.13 per bbl of NGL utilizing a benchmark of $6.36 per mmbtu of natural gas and $94.14 per bbl of oil and condensate.

During the year ended December 31, 2021, we added approximately 868.2 bcfe in proved reserves through the continued development of our Utica Shale acreage. Upward revisions of previous estimates of approximately 87.9 bcfe were primarily driven by SEC price improvements which resulted in an increase of 176.8 bcfe, partially offset by a decrease of 88.9 bcfe due to the removal of PUDs where it was determined development would occur outside of our five-year development plan, net of positive performance revisions and development plan optimization. As of December 31, 2021, all proved undeveloped locations were in accordance with the SEC five-year rule. The average adjusted prices used to calculate reserves as of December 31, 2021 were $3.56 per mcf for natural gas, $59.39 per bbl for oil and $31.89 per bbl of NGL utilizing a benchmark of $3.60 per mmbtu of natural gas and $66.55 per bbl of 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, 2023, 2022 and 2021 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 a 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)	2023	2022	2021
Future cash inflows	$ 24,087,843	$ 57,745,828	$ 36,002,574
Future production costs	(14,815,731)	(15,387,792)	(15,079,666)
Future development costs	(1,812,994)	(2,206,486)	(1,850,383)
Future net cash flows	7,459,118	40,151,550	19,072,525
Discount to present value at 10% annual rate	(3,965,722)	(21,111,851)	(9,936,965)
Standardized Measure of Discounted Future Net Cash Flows	$ 3,493,396	$ 19,039,699	$ 9,135,560

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:

	Year Ended December 31,		
($ in thousands)	2023	2022	2021
Standardized Measure of Discounted Future Net Cash Flows, Beginning of Period	$ 19,039,699	$ 9,135,560	$ 1,265,100
Sales of natural gas, oil and NGL produced, net of production costs	(1,080,313)	(4,059,098)	(1,874,116)
Net changes in prices and production costs	(17,949,035)	12,204,960	9,049,798
Extensions and discoveries, net of production and development costs	483,294	1,698,834	962,303
Changes in future development costs	198,241	(781,366)	(68,401)
Development costs incurred	542,027	595,026	310,194
Revisions of previous quantity estimates	(102,270)	(1,468,592)	58,031
Purchase of reserves	—	350,314	—
Accretion of discount	1,903,970	913,556	126,510
Changes in production rates and other	457,783	450,505	(693,859)
Standardized Measure of Discounted Future Net Cash Flows, End of Period	$ 3,493,396	$ 19,039,699	$ 9,135,560